Alberta
Freedom To Create. Spirit To Achieve.

Energy

Annual Report
2010-2011

Government of Alberta

Energy

2010-2011

CONTENTS

Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Government Accountability Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 24 Ministries.

The annual report of the Government of Alberta released June 29, 2011 contains Ministers' accountability statements, the consolidated financial statements of the Province and *The Measuring Up* report, which compares actual performance results to desired results set out in the government's business 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 (DOE), the Energy Resources Conservation Board (ERCB), the Alberta Utilities Commission (AUC), the Alberta Petroleum Marketing Commission (APMC) and the Post-Closure Stewardship Fund;**
- **other financial information as required by the *Financial Administration Act* and *Government Accountability 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, 2011, was prepared under my direction in accordance with the *Government Accountability Act* and the government's accounting policies. All of the government's policy decisions as at June 22, 2011 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

Original signed by Ron Liepert

Honourable Ron Liepert
Minister of Energy

Message from Minister

The 2010-2011 fiscal year was a turning point for the Department of Energy and the Government of Alberta. With the world still feeling the lingering effects of a global recession, Alberta positioned itself to come out of the recession confident and poised for unprecedented economic growth and activity.

We took steps to ensure our fiscal framework for royalties was generating as much investment in Alberta as possible during this time. Our framework was updated to encourage greater use of new technology when it came to oil and gas development. Judging by our land sales results, a key indicator for industry confidence, it appears our efforts to leave the recession behind us were successful.

The final numbers for petroleum and natural gas land sales for the 2010-2011 fiscal year show that industry paid a record $2.5 billion to the province. This surpassed the previous record set in 2005-2006 by nearly half a billion dollars.

Oil sands activity also showed resurgence this past year. Capital spending was estimated to be $16 billion, up from just under $13.5 billion in 2009.

Government also continued to strengthen Alberta's investment competitiveness and demonstrate that Alberta is a secure environmentally responsible supplier of energy. A cross-ministry task force, mandated to envision a more efficient and effective regulatory system, delivered its report to government. The task force made several recommendations to ensure Alberta has a modern regulatory system that maintains our commitment to the environment, safety and conservation.

Extracting additional wealth from our resources and creating new jobs, income and opportunities for Albertans was another key goal of the Department. Excellent progress was made this past year with our Bitumen Royalty in Kind (BRIK) initiative. This initiative proposes to advance upgrading and refining of bitumen in Alberta by providing access to physical bitumen to support its strategic objectives. We were also successful in completing an agreement for the construction of a new 50,000 bpd upgrader in Alberta's Industrial Heartland to process BRIK volumes once construction is completed.

As part of this initiative, we also agreed to terms and conditions to build the first major carbon capture and storage (CCS) project in the province. The Alberta Carbon Trunk pipeline will deliver carbon dioxide from this refinery for use in Enhanced Oil Recovery projects. This will increase recoveries from Alberta's conventional oil reserves.

Advancements were also made relative to the province's CCS initiatives. We passed legislation that will guide how large-scale CCS projects will proceed in Alberta. This makes Alberta the first province in Canada to introduce comprehensive legislation for this greenhouse gas reduction technology. The captured CO_2 can also be used for Enhanced Oil Recovery to increase production from depleting conventional reservoirs. The Alberta Carbon Capture and Storage Development Council estimates that carbon captured and used in enhanced oil recovery could produce an additional 1.4 billion barrels of oil from conventional reservoirs generating up to $25 billion dollars in provincial royalties and taxes.

We have also enlisted the assistance of international expertise to guide a carbon capture and storage regulatory review. This review will focus on environmental, safety and assurance processes for carbon capture and storage. Alberta is committed to the safe and responsible development of CCS – a key method of greening our energy production. Before anything is injected from these projects, be assured, we will have a world-class regulatory framework in place to ensure extensive measuring, monitoring and verification of these projects.

We also continued to support the advancement of technology through the Innovative Energy Technologies Program. The program was expanded this past year to increase extraction of ethane and support continued growth of Alberta's petrochemical sector.

Alberta is building on its reputation as a major player in the bioenergy sector with the implementation of a Renewable Fuels Standard. To ensure the success of the Renewable Fuels Standard and to support bioenergy production in the province, government expanded and extended the Bioenergy Producer Credit Program until 2016. The program includes a wide variety of bioenergy products, including commercial wood pellets and cogeneration for electricity and heat production. These projects are creating new value-added products, spurring investment and contributing to important clean energy research.

In terms of renewable energy, Alberta is leading Canada in wind development with more than double the installed wind capacity of the national average. In 2010, Alberta had more than 800 megawatts (MW) of wind generation capacity. When all units are generating at maximum output, they produce enough energy to serve over 900,000 homes.

We know demand will continue to increase and Alberta will be a major energy supplier to the world. We will continue to adhere to some of the highest standards for environmental performance in the world. Now more than ever the world needs secure, reliable sources of energy from regions with stable government, transparent democracies and attractive fiscal regimes. Alberta's continued growth and prosperity rests on our ability to integrate energy production with environmental sustainability. We are meeting this challenge head on.

Original signed by the Honourable Ron Liepert

Honourable Ron Liepert
Minister of Energy

Management's Responsibility for Reporting

The Ministry of Energy includes:

- Alberta Department of Energy (DoE/Department)
- Energy Resources Conservation Board (ERCB)
- Alberta Utilities Commission (AUC)
- Alberta Petroleum Marketing Commission (APMC)
- 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, we oversee the preparation of the Ministry's Annual Report, including consolidated financial statements and the 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 the 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 results.
- Completeness – Performance measures and targets match those included in Budget 2010.

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 Enterprise and the Minister of Energy of information needed to fulfill their responsibilities; and
- facilitate preparation of Ministry business plans and annual reports required under the *Government Accountability Act*.

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

Peter Watson
Deputy Minister,
Department of Energy

Dan McFadyen,
Chairman, Energy Resources
Conservation Board

Willie Grieve,
Chairman, Alberta
Utilities Commission

Ministry Overview

The Alberta Crown owns approximately 81 per cent of Alberta's minerals – including oil, natural gas, oil sands and coal and other mineral resources. The remaining 19 per cent are freehold mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies.

The Ministry of Energy manages Alberta's energy resources for the benefit of Albertans, helping ensure they are developed in environmentally responsible ways that bring benefits to Albertans.

The Ministry consists of the Department of Energy (DoE), the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC). The Minister of Energy is also accountable for the Alberta Petroleum Marketing Commission, which is fully integrated operationally within the DOE. Each plays important roles in overseeing the orderly development of Alberta's energy resources.

DoE	• Is the steward of Alberta's energy system on behalf of all Albertans. • Develops policy for and manages development of Alberta's non-renewable resources (including natural gas, conventional oil, oil sands, coal, and petrochemicals) and renewable energy. • Grants industry the right to explore for and develop Alberta's energy and mineral resources. • Establishes, administers and monitors the effectiveness of Alberta's fiscal and 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.

ERCB	• Regulates the safe, responsible and efficient development of Alberta's energy resources: oil, natural gas, oil sands and coal. • Independently makes decisions regarding resource development in accordance with applicable legislation and within the framework of Alberta's overall energy policy. • Establishes and applies technical standards for the safe and reliable operation of energy facilities in the province. • Ensures that the discovery, development and delivery of Alberta's energy resources take place in a manner that is fair, responsible and in the public interest.

AUC	
AUC	• Regulates investor-owned, and some municipality-owned, electric, natural gas and water utilities to ensure Albertans receive safe and reliable utility service at reasonable rates. • Independently makes decisions on the siting of electric power plants, electric transmission facilities and natural gas transmission pipelines. • Makes rules relating to the operation of the retail natural gas and electricity markets and adjudicates on market and operational rule contraventions brought to it by the Market Surveillance Administrator. • Ensures the delivery of Alberta's utility services takes place in a manner that is fair, responsible and in the public interest.

The Energy Story 2010-2011

Alberta's foundations are built on energy. Energy development has shaped Alberta's history, communities and growth, and it stands to play an important role in Alberta's future.

Energy is Alberta's future. Global demand needs a secure and reliable source and the province is in a unique position to address market and environmental challenges, securing our future success.

Events of 2010-2011 have challenged energy development and the operation of markets. Continued worry about local and global economies, slow or stagnant economic growth and continuing political clashes in Northern Africa and the Middle East threatened global energy stability and supply. Climate change policies and the continuing ascent of China as a powerful driver of the global economy are changing the dynamics and positions of the world's energy players.

These events and changes highlight the important role Alberta occupies as a stable, responsible energy supplier.

2010-2011 was an opportunity. The Government of Alberta worked to foster greater understanding of the province's role as a secure and reliable energy supplier and a source of economic activity. This meant sharing our goal of clean energy production, our respect for the environment and our protection of public safety.

Renewed activity in the oil and gas sector led Alberta's continued recovery from the downturn of 2008-2009.

Industry confidence was evident in the record year for petroleum and natural gas land sales. In 2010-2011 over $2.5 billion was raised for Albertans, surpassing the previous record set in 2006 by over $400 million. Oil sands investment also increased by $3 billion from the previous year to an estimated $16 billion. For approximately one dollar investment, there is roughly nine dollars in economic stimulus. In-situ projects will also contribute to oil sands spending this year.

Strong growth in developing economies has supported robust demand for petroleum products. Strong oil prices are also expected in response to increased demand from strong economic growth in countries like China and India. Every one dollar increase in the price of oil is worth $141 million to Alberta.

Diverse mineral exploration activity also contributes to innovation with mineral researchers developing technologies to mine industry waste products (e.g. titanium from oil sands tailings).

Alberta's workforce has more options as the active rig count is up over fifty per cent compared to the previous year. For each rig drilled, an estimated that 135 jobs are created, directly and indirectly.

The DoE led several key initiatives for responsible and sustainable development. Highlights are included below.

Competitiveness

To advance Alberta's competitiveness in the upstream oil and gas sector, a Competitiveness Review assessed how the province could improve its ability to attract conventional oil and natural gas investment, in light of market changes and realities. This included an extensive consultation process with stakeholders.

Energizing Investment, the assessment report, included modifications to conventional oil and natural gas royalty rates, action to promote innovation and use of new technologies and recommendations to conduct a complete overhaul of the province's regulatory system resulting in a single regulatory body.

Royalty adjustments included:

- A permanent incentive program rate of five per cent on new natural gas and conventional oil wells;
- A new maximum royalty rate of 40 per cent for conventional oil; and
- A new maximum royalty rate of 36 per cent for conventional and unconventional natural gas.

These rates were effective on a permanent basis for the January 2011 production month.

As conventional natural gas plays in Alberta mature, industry is looking at other potential sources. As result of these royalty adjustments, there is considerable attention on using new technologies to extract unconventional sources, such as shale gas. While it is not known how much of the shale gas can be economically produced, current unconventional natural gas experience suggests recoverable reserves are about five to ten per cent of the resource potential.

For the Government of Alberta, promoting innovation means making sure enhanced oil and gas recovery technologies remain a priority in research strategies with industry and academic partners.

On the front end of industry resource development, a Regulatory Enhancement Task Force led a comprehensive upstream oil and gas regulatory review. Recommendations from the Task Force are focused on a modern, efficient, outcomes-based and competitive regulatory system that maintains the province's strong commitment to environmental management, public safety and resource conservation.

Regulatory Enhancement Task Force and Report

The Regulatory Enhancement Task Force's review included analyses of all processes to develop and ensure compliance with provincial policies around upstream oil and gas development. First Nations, the oil and gas industry, landowners, municipal representatives and environmental groups were engaged through briefings, meetings, workshops and a forum.

Enhancing Assurance, the Task Force's January 2011 report, included six recommendations, which were accepted:

- establish a new Policy Management Office and ensuring integration of natural resource policies;
- create a single oil and gas regulatory body;
- provide clear public engagement processes;
- use a common approach to risk assessment and management;
- adopt performance measures to enable continuous system improvement; and
- create a mechanism to help resolve disputes between landowners and companies, and enforce agreements where required.

Bitumen Royalty-In-Kind

In pursuing our goal to add value to our resources, this past year saw the Government of Alberta successfully negotiate contracts for two projects to advance upgrading and refining of bitumen in Alberta, increase supplies of diesel fuel and enhance Alberta's position as a secure supplier of clean energy.

As the steward of energy resources for Albertans, the Government of Alberta is entitled to take its royalty share of bitumen production in the form of bitumen, rather than cash royalties. Bitumen royalty-in-kind adds value to the bitumen resource, diversifies Alberta's economy, increases resource revenues and create jobs in the province.

The first project will lead to construction of a new bitumen refinery in Alberta's Industrial Heartland. This project allows for the processing of the Crown's bitumen for a fee, which will result in the Crown receiving higher revenues created by the higher-priced refined bitumen products.

The second project will see the first major carbon capture and storage (CCS) project in the province and consists of the construction of a pipeline to deliver carbon dioxide captured from the bitumen refinery. The carbon dioxide will be transported to conventional oil recovery projects throughout central Alberta for enhanced oil recovery.

The refinery is expected to produce more than 5.5 million litres/day of ultra-low sulphur diesel while capturing over three thousand tonnes of carbon dioxide daily.

These projects represent a major step forward in producing value-added products while at the same time reducing greenhouse gas emissions. The potential of CCS and enhanced conventional oil recovery ensures on-going jobs, investment and economic activity in surrounding communities.

Value Added

Alberta's petrochemical industry is the largest in Canada. The sector employs 7,500 Albertans, contributes to a diversified labour market and adds value to Alberta's economy.

Changes to the Incremental Ethane Extraction Program were made to increase extraction of ethane and to support the continued growth of Alberta's petrochemical sector. The program was initially designed to encourage extraction of ethane from natural gas. The revisions will help encourage more ethane extraction from bitumen refining or upgrading off-gases. Capturing these off-gases will reduce greenhouse gas emissions.

The Incremental Ethane Extraction Program is designed to:

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

Carbon Capture and Storage

The Government of Alberta made key advancements to further the CCS potential in the province.

The province introduced and passed legislation in 2010 that guides how large-scale CCS projects will proceed in Alberta. This step made Alberta the first province in Canada to introduce comprehensive legislation for this greenhouse gas reduction technology.

The *Carbon Capture and Storage Statutes Amendment Act*, 2010, clarified ownership of pore space, which are gaps in porous rock where carbon would be stored. Under the legislation, the Government of Alberta accepted long-term liability for injected carbon dioxide. The legislation also establishes a fund financed by CCS operators for ongoing monitoring costs and any required remediation.

In addition, an expert panel was created to guide Alberta's CCS Regulatory Framework Assessment. This process will examine in detail the environmental, safety and assurance processes for CCS that exist and determine what, if any, new processes need to be put in place for commercial scale deployment of this technology.

This review is an important step in creating a world-class regulatory framework for CCS activities.

Renewable Fuels

Building on our reputation as a major player in the bioenergy sector, Alberta has officially implemented a Renewable Fuels Standard.

The standard requires an annual average of two per cent renewable diesel in diesel fuel and five per cent renewable alcohol in gasoline sold in Alberta. The greenhouse gas emissions of renewable diesel or alcohol must be at least 25 per cent lower than the equivalent petroleum fuel. Alberta was the first Canadian jurisdiction to commit to a greenhouse gas emission threshold for renewable fuel supporting a Renewable Fuels Standard.

The expanded and extended Bioenergy Producer Credit Program will help ensure the success of the Renewable Fuels Standard. The Program supports production of a wide variety of bioenergy products, including renewable fuels, encouraging Alberta biofuel production.

New West Partnership - Energy Memorandum of Understanding

Energy ministers from Alberta, British Columbia and Saskatchewan signed an Energy Memorandum of Understanding (MOU) to combine and build on the existing strength of the provinces to expand Western Canada's energy sector.

This includes attracting new investment, stimulating job creation and strengthening the region's economy. Actions include developing a joint strategy to target opportunities in Asia and improving consultation with industry.

Longer-term projects under the MOU are expected to include regulatory streamlining, continued promotion of the region's energy goods and investment opportunities and acceleration of the development and use of green energy sources.

Coalbed Methane Legislation

The Mines and Minerals (Coalbed Methane) Amendment Act, 2010 proposed that coalbed methane is, and always has been, natural gas for both Crown and freehold minerals. Under the Act, coalbed methane is owned by the holder of the natural gas rights. These changes clarify coalbed methane ownership and remove potential barriers to coalbed methane development on freehold land in Alberta.

Telling the Alberta Story

The DoE has led local, national and international energy-related engagement and advocacy efforts. Our focus has evolved from sharing accurate information on our energy development to an expanded dialogue highlighting Alberta's clean energy story. We continue to address misinformation on how the province develops its energy resources. Potential misunderstandings risk continued access to markets and our ability to develop new international markets.

To further engage with industry, we have increased our presence in Calgary, home to many energy corporate offices. Outside of our borders, national and international missions to share our story have included trips to Ontario, Alaska, New Mexico, New York, Washington, Mississippi and Louisiana. Overseas trips include the United Kingdom and Belgium. Looking forward, ongoing relationships with industry, local, national or international, will strengthen our growth and prosperity.

Energy is Alberta's and the country's economic driver. We are the secure and reliable source of energy. Increasing global demand is our opportunity to showcase leadership and environmentally responsible development.

Energy Highlights

Resource		2010-11	2009-10
Natural Gas and By-Product Royalty	Revenue	$1.42 billion	$1.53 billion
	Percentage of non-renewable resource revenue	14 per cent	19 per cent
	Average Alberta Gas Reference Price (ARP)	$3.28/GJ	$3.58/GJ
	Number of conventional natural gas wells drilled	3,663 (2010)	3,208 (2009)
	Total marketable natural gas production including Coalbed Methane (CBM)	4.1 trillion cubic feet (Tcf) (2010)	4.4 trillion cubic feet (Tcf) (2009)
	CBM production (excluding comingled gas)	261 billion cubic feet (Bcf) (2010)	229 billion cubic feet (Bcf) (2009)
	Total natural gas deliveries	3.9 Tcf (2010)	4.3 Tcf (2009)
	• To the United States	45 per cent	43 per cent
	• Within Alberta	29 per cent	27 per cent
	• To rest of Canada	26 per cent	30 per cent
Conventional Crude Oil	Revenue	$2.24 billion	$1.85 billion
	Percentage of non-renewable resource revenue	22 per cent	23 per cent
	Average price for West Texas Intermediate (WTI)	US$83.46/barrel (bbl)	US$70.77/barrel (bbl)
	Crude oil production	459,000 barrels per day (2010)	461,000 barrels per day (2009)
	Pentanes and condensate production	123,000 barrels per day (2010)	128,000 barrels per day (2009)
	Crude oil wells drilled	2,259 (2010)	911 (2009)
Oil Sands	Revenue	$3.72 billion	$3.16 billion
	Percentage of non-renewable resource revenue	36 per cent	40 per cent
	Bitumen wells drilled	2,697 (2010)	2,211 (2009)
	Oil sands production		
	• Total bitumen	1.61 million barrels per day (2010)	1.49 million barrels per day (2009)
	• Marketable bitumen and SCO	1.47 million barrels per day (2010)	1.35 million barrels per day (2009)
Combined Conventional and Synthetic Crude Oil	Revenue	$5.96 billion	$5.01 billion
	Production	2.05 million barrels per day (2010)	1.94 million barrels per day (2009)
	Total crude oil deliveries	2.26 million barrels per day (2010)	2.31 million barrels per day (2009)
	• To the United States	60 per cent	60 per cent
	• Within Alberta	20 per cent	21 per cent
	• To rest of Canada	16 per cent	16 per cent
	• Offshore	4 per cent	3 per cent

Resource		2010-11	2009-10
Bonuses From the Sale of Crown Leases	Revenue (bonus, plus application fees, plus first year's rent)	$2.64 billion	$1.16 billion
	Average price per hectare paid at petroleum and natural gas rights sales	$668.08	$512.12
	Petroleum and natural gas hectares sold at auction	3,840,957 hectares	2,210,393 hectares
	Average price per hectare paid for oil sands mineral rights	$150.09	$133.42
	Oil sands hectares sold at auction	365,970 hectares	61,257 hectares
	Bonus (total amounts bid on parcels of land) received from public offering of Crown petroleum and natural gas and oil sands rights	$2.62 billion	$1.14 billion
Freehold Mineral Tax	Revenue	$127 million	$124 million
Wells and Licences	Well licences issued	11,236 (2010)	8,161 (2009)
	Industry drilling	9,233 (2010)	6,980 (2009)
Coal	Revenue	$31 million	$31 million
	Established coal reserves (estimate)	33.3 billion tonnes (36.8 billion tons) (2010)	33.4 billion tonnes (36.8 billion tons) (2009)
	Raw coal production	38.5 million tonnes	38.5 million tonnes
	Total marketable coal deliveries	31.8 million tonnes (2010)	30.9 million tonnes (2009)
	Percentage of total coal deliveries exported out of the province	22.6 per cent (2010)	20 per cent (2009)
Electricity	Total generation capacity	13,071 MW (2010)	12,997 MW (2009)
	Total generation capacity from renewable sources	2,045 MW (2010)	1,814 MW (2009)
	Total generation capacity from coal	5,735 MW (2010)	5,971 MW (2009)
	Total generation of electricity	70,586 MWh (2010)	69,262 MWh (2009)
	Amount of Alberta's electricity supplied by renewable resources	5 per cent (2010)	5 per cent (2009)
	Amount of Alberta's electricity supplied by coal	58 per cent (2010)	60 per cent (2009)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	$835,823	$658,732
	Hectares of mineral permits issued to exploration companies (LAMAS, MIM Permits and New Applications Issued)	1,837,740 hectares	2,559,856 hectares

Data Sources: all information is from ERCB's ST98-2011: Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2010-2011 report; except those otherwise indicated. All financial numbers are from Alberta Energy.

RESULTS ANALYSIS

Review Engagement Report

To the Members of the Legislative Assembly

I have reviewed the performance measures identified as “Reviewed by Auditor General” in the *Ministry of Energy’s 2010-11 Annual Report*. These performance measures are the responsibility of the Ministry and are prepared based on the following criteria:

- Reliability - Information agrees with the underlying data and with sources used to prepare it.
- Understandability and Comparability - Current results are presented clearly in accordance with the stated methodology and are comparable with previous results.
- Completeness - Performance measures and targets match those included in Budget 2010.

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 my Office by the Ministry. My review was not designed to provide assurance on the relevance of these performance measures.

A review does not constitute an audit and, consequently, I do not express an audit opinion on the performance measures.

Based on my review, nothing has come to my attention that causes me to believe that the “Reviewed by Auditor General” performance measures in the Ministry’s 20 10-1 1 Annual Report are not, in all material respects, presented in accordance with the criteria of reliability, understandability, comparability, and completeness as described above. However, my review was not designed to provide assurance on the relevance of these performance measures.

Original signed by Merwan N. Saher, CA

Auditor General

June 7, 2011
Edmonton, Alberta

Performance Measures Summary Table

Goal/Performance Measure	Target	Last Actual	Previous Actuals Year	Previous Actuals Year
Goal 1:				
Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions	Alberta will have a combined royalty and tax rate that is in the top quartile of investment opportunities compared to similar jurisdictions	**Alberta within First Quartile** (2009) **39.73% (Natural Gas)** **43.02% (Conventional Oil)**	n/a (2008)	n/a (2007)
Goal 2:				
Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are accurately calculated Demonstration of checks, internal audits, process for correcting errors, and that any errors have been corrected				
• Oil	100%	**100%**	100%	n/a
• Oil Sands (Royalty)	100%	**100%**	100%	n/a
• Oil Sands (Tenure)	100%	**100%**	100%	n/a
• Gas	100%	**100%**	100%	n/a
• Land Sale Bonuses	100%	**100%**	100%	n/a
		(2009)	(2008)	(2007)
Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are fully collected: * Percentage of amounts collected compared to amounts owed				
• Oil	100%	**100%**	100%	n/a
• Oil Sands (Royalty)	100%	**100%**	100%	n/a
• Oil Sands (Tenure)	100%	**100%**	100%	n/a
• Gas	100%	**100%**	100%	n/a
• Land Sale Bonuses	100%	**100%**	100%	n/a
		(2009)	(2008)	(2007)
Goal 3:				
Carbon Capture and Storage: Report annual storage of carbon dioxide in Alberta	5 Megatonnes by 2015	**n/a (2010)**	n/a (2009)	n/a (2008)
Upstream Oil and Gas Industry Investment: Annual capital expenditure in Alberta on exploration and development of oil, oil sands and gas resources ($ billions)	23 to 30	**21.6 (2009)**	40.1 (2008)	37.7 (2007)
Goal 4:				
Ethane Demand in Alberta In barrels per day	60,000 – 85,000 additional barrels per day	**216,600 (2010)**	222,000 (2009)	223,000 (2008)
Ethanol Production in Alberta Millions of litres	150 million to 300 million	**40 (2010)**	40 (2009)	40 (2008)
Biodiesel Production in Alberta Millions of litres	55 million to 110 million	**19 (2010)**	19 (2009)	19 (2008)

Goal/Performance Measure	Target	Last Actual	Previous Actuals Year	Previous Actuals Year
Goal 5:				
Albertans' Assessment of their Energy Knowledge	71%	**63% (2011)**	n/a (2010)	70% (2009)
Goal 6:				
Increased Fuel Gas Efficiency Reporting: Percentage of total fuel gas used by industry participants who voluntarily reported fuel gas efficiency information	72%	**68% (2009)**	n/a (2008)	70% (2007)
Goal 7:				
Magnitude of Transmission Must Run (TMR) Congestion (GWh)	Continuous Improvement	**792 (2009)**	1,005 (2008)	n/a (2007)
Magnitude of Constrained Down Generation (GWh)	Continuous Improvement	**55 (2009)**	295 (2008)	n/a (2007)
Transmission Losses (%)	Continuous Improvement	**3.6% (2009)**	3.8% (2008)	n/a (2007)
Number of Microgeneration Sites	Continuous Improvement	**216 (2010)**	122 (2009)	41 (2008)
Goal 8:				
Data Accessibility: Percentage of Department facilitated research documents filed in a research repository, with public access wherever possible	90%	**n/a (2009)**	n/a (2008)	n/a (2007)
Goal 9:				
Power Generation * Margin (MW) between Firm Generating Capacity and Peak Demand	Maintain a minimum 7% margin over peak load	**17% (2010)**	18% (2009)	20% (2008)
Goal 10:				
Regulatory Noncompliance * Percentage of field inspections finding High Risk regulatory noncompliance (ERCB)	Less than or equal to 3.0%	**1.7% (2010)**	1.7% (2009)	2.1% (2008)
Timeliness of the Needs and Facility Applications Percentage of needs and facility applications determined within 180 days of the application being deemed complete (AUC)	100%	**100% (2010)**	92% (2009)	100% (2008)

Goal/Performance Measure	Target	Last Actual	Previous Actuals Year	Previous Actuals Year
Goal 11:				
Industry satisfaction				
• with Department services	80% or higher	**82% (2009)**	83% (2007)	84% (2005)
• with Department electronic information management	80% or higher	**90% (2009)**	90% (2007)	90% (2005)
Work Environment				
Department				
• Employee Engagement	80% or higher	**68% (2010)**	75% (2009)	76% (2008)
• Quality Work Environment	80% or higher	**71% (2010)**	75% (2009)	77% (2008)
ERCB				
• Employee Engagement	75%	**73% (2010)**	80% (2009)	81% (2008)
• Quality Work Environment	78%	**75% (2010)**	79% (2009)	80% (2008)
AUC				
• Employee Engagement	80%	**75% (2010)**	81% (2009)	88% (2008)
• Quality Work Environment	80%	**78% (2010)**	81% (2009)	86% (2008)

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

1. **Enduring measures that best represent the goal and mandated initiatives,**
2. **Measures for which new data is available,**
3. **Measures that have well established methodology.**

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

Discussion and Analysis of Results

Expenses

Expense by Core Business

Financial Resources (thousands of dollars)	
Planned Spending (Estimates)	$456,527
Actual Spending in 2010-11	$352,453
Actual Spending in 2009-10	$387,961

Alberta Energy received $456.5 million in approved Planned Spending (Estimates) in 2010-2011.

Total expenditures in 2010-2011 were lower than Estimates by $104.1 million, primarily due to a reduction for carbon capture and storage support.

Overall in 2010-2011, the Ministry realized a net $35.5 million decrease in actual spending compared to 2009-2010. This was largely attributable to the end of the one-year Well Abandonment and Reclamation program.

Expense by Core Business (Operating Expense)

Core Business	Spending (thousands)	% of Total
Core Business 1: Assuring energy supply and benefits from energy and mineral resource development for Albertans	$ 132,360	37.6%
Core Business 2: Leading and engaging citizens, communities, industry and governments to achieve effective stewardship of Alberta's energy resources	$ 8,085	2.3%
Core Business 3: Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems	$ 212,008	60.1%
TOTALS	**$ 352,453**	**100%**

In accordance with the Government of Alberta accounting principles, Alberta Energy classifies its expenses into four functions. Each of these functions identifies the principal purpose for which Ministry expenditures are incurred.

Expense by Function

Expense by Function by Dollars (in thousands)	2010-11 Budget (Estimates)	2010-11 Actual	Comparable 2009-10 Actual
Agriculture, Resource Mgmt and Economic Development	$ 352,983	$ 252,153	$ 261,171
Transportation, Communications and Utilities	$ 36,228	$ 31,601	$ 30,675
Environment	$ 13,000	$ 13,094	$ 43,000
General Government	$ 54,316	$ 55,605	$ 53,115
TOTAL MINISTRY	**$ 456,527**	**$ 352,453**	**$ 387,961**

In relation to the Environment function, the decrease in actual spending in 2010-2011 compared to 2009-2010 is the result of the end of the one-year Well Abandonment and Reclamation program in the amount of $30.0 million.

Overall, approximately 72 per cent of the Ministry's expenditures support the function of Agriculture, Resource Management and Economic Development. A significant amount of actual expenses for 2010-2011 relate to energy regulation expenses ($167 million, or 47 per cent).

Financial Highlights

(Cdn $ millions)	2010-11	2009-10	2008-09	2007-08	2006-07
Natural gas and by-products	1,416	1,525	5,834	5,199	5,988
Conventional crude oil royalties	2,236	1,848	1,800	1,655	1,400
Bonuses from the sale of Crown leases	2,635	1,165	1,112	1,128	2,463
Bitumen	3,723	3,160	2,973	2,913	2,411
Rentals and fees	161	158	160	159	159
Coal	31	31	36	14	13
Drilling Stimulus initiatives	-1,774	-1,119			
Alberta Royalty Tax Credit	-	-	-	-44	-174
Total Non-Renewable Resource Revenue	8,428	6,768	11,915	11,024	12,260
Freehold Mineral Tax	127	124	261	247	317
Other revenue*	157	188	183	142	136
Total Revenue	8,712	7,080	12,359	11,412	12,713
Expenses*	352	388	395	296	223
Net Ministry of Energy Revenue	8,360	6,692	11,964	11,116	12,490

* Revenues and expenses are for the DOE, ERCB and AUC

GOAL 1 **Linked to Core Business 1 – Assuring energy supply and benefits from energy and mineral resource development for Albertans**

Alberta has a competitive and effective royalty system, incenting development and maximizing benefits to Albertans

Alberta will sustain a royalty regime which attracts industry investment, creating economic activity and jobs. It also enables that government, as the resource owner, receives an appropriate share of revenues from the development of these resources. A strong energy sector provides royalties for Albertans, jobs, business opportunities, tax revenue, and numerous other benefits to the provincial economy. Success is measured by sustaining vibrant industry activity, and a competitive fiscal regime that attracts investment.

Key Achievements

The Department of Energy regularly monitors and reports on the competitiveness of Alberta's natural gas and conventional oil fiscal regimes. The competitiveness monitoring and reporting is comprehensive and incorporates information reflected in the performance measure as well as the supplemental information stated within the 2010-2013 Energy Business Plan.

Balancing the Fiscal Regime

On March 11, 2010, the Alberta Government announced the results of the Alberta Natural Gas and Conventional Oil Investment Competitiveness Study which contains an extensive technical analysis of Alberta's competitive position. The study resulted in a number of recommendations for improvement in specific areas, including modification of conventional oil and natural gas royalty rates; steps to ensure improvements to the effectiveness and efficiency of Alberta's regulatory processes while protecting the environment; greater flexibility and support for the use of newer technologies in upstream development; and strengthening the productive partnership between Albertans and the resource industry.

In conjunction with this announcement, the Alberta Government released their response document, *Energizing Investment,* a framework to improve Alberta's natural gas and conventional oil competitiveness. These adjustments are designed to improve the provincial regulatory regime and drive innovation – positive changes for Alberta's investment climate and a strong economic recovery.

Significant changes to the *Alberta Royalty Framework* were finalized and applied. The goal is to continue positioning Alberta as an attractive destination, and include:

- Updated the gas and oil royalty curves to improve investment economics and provide a better risk-reward balance, making Alberta a more attractive location for energy investment.
- Adjusted the *Natural Gas Deep Drilling Program* (NGDDP) vertical depth requirement, improving economics for a number of wells in the Alberta Deep Basin. These changes encourage additional deep basin drilling, adding to provincial energy reserves and royalty receipts.
- Made the *New Well Royalty Rate* a permanent feature of the royalty system which provides an initial five per cent royalty rate for new wells, for the lesser of 12 producing months or 50,000 barrels of oil production or 500,000 cubic feet of natural gas production. This improves investment returns within a timeframe that improves overall economics and provides cash flows for reinvestment. New wells were no longer allowed to select transitional royalty rates as of January 1, 2011. The program will continue as implemented until December 31, 2013 for wells that have already selected transition rates, with an option for companies to move to *Alberta Royalty Framework* royalty rates effective January 1, 2011.

Driving Innovation

An extended five per cent initial royalty rate was implemented to encourage the use of newer, higher risk technologies for horizontal oil and gas well drilling, and drilling for emerging resources. The rate applies to a specified volume of oil or gas and a production time period dependent on the technology used or reserve being developed. Implementation of this rate structure allows for risk reduction and an investment climate that fosters exploration and development in new energy prospects in Alberta.

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 royalty and tax rate that is in the top quartile of investment opportunities compared to similar jurisdictions.

Results:

	Actual 2007	Actual 2008	Year Ending December 31 Last Actual 2009
Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions	n/a	n/a	Alberta within First Quartile[1] 39.73% (Natural Gas) 43.02% (Conventional Oil)

Source: Alberta Department of Energy

Note:

[1] First quartile threshold: natural gas, up to 49.05 per cent; conventional oil, up to 49.10 per cent.

Discussion of Results

To realize the goal that Alberta has a competitive and effective royalty system that incents development and maximizes benefits to Albertans, it is not enough to focus solely on the royalty regime. While the performance measure indicated that Alberta had a competitive combined tax and royalty rate amongst competing jurisdictions, other indicators signaled that Alberta's lagging energy sector was not only the result of a world-wide recession, but that it was also losing its competitive edge; land sales, investment, drilling activity, and production all declined more than other jurisdictions. Based on these supplementary indicators, Alberta Energy led an initiative to ensure Alberta can compete for and successfully attract high levels of capital investment in its energy sector over the long term. This initiative (the Investment Competiveness Study) was future focused and accounted for the many factors that influence investment decisions (in addition to fiscal regime parameters). The results of this work culminated in *Energizing Investment: A Framework to Improve Alberta's Natural Gas and Conventional Oil Competitiveness*.

Energy Industry Indicators	2010-11	2009-10
Conventional Oil Production (barrels per day)	456,000	464,000
Oil Sands Production (barrels per day)	1,493,000	1,638,000
Total Crude Oil Production (barrels per day)	1,949,000	2,102,000
Natural Gas Production (trillion cubic feet)	4,761,000	4,529,000
Oil Price (WTI US$/b)	$83.38	$70.71
Oil Price (WCS@Hardisty C$/b)	$66.70	$66.08
Alberta Natural Gas Reference Price (C$/GJ)	$3.28	$3.58
Land Sales (hectares)	4,356,344	2,275,333
Price per Hectare	$604.87	$511.57
Land Sale Revenue ($ millions)	$2,635	$1,164
Total Metres Drilled	13,018,839	9,261,544
Average # of Active Drilling Rigs	233	148

Energy and mineral resource revenues are accurately calculated, collected and reported

Energy's business processes, systems and controls result in accurate calculation, assessment and collection of all amounts that should be collected.

Key Achievements

Maintaining effective working relationships with industry are fundamental to successfully implement recommendations from the *Competiveness Review* regarding the completeness and accuracy of filings. A series of meetings and information sessions were held with industry, and the Department continues to respond to industry's questions and concerns on all related matters.

In addition, Energy's information technology infrastructure, business systems, security, and processes continue to ensure accurate, timely, and effective resource revenue assessment and collection for Albertans. New business solutions were successful in meeting the emerging business priorities and technology drivers in support of these essential business operations.

Performance Measure:

2.a Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are accurately calculated

Target:

100 per cent of revenues are accurately calculated.

Results:

Year Ending December 31

	Actual 2007	Actual 2008	Last Actual 2009
Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are accurately calculated: Demonstration of checks, internal audits, process for correcting errors, and that any errors have been corrected			
• Oil	n/a	100%	100%
• Oil Sands (Royalty)	n/a	100%	100%
• Oil Sands (Tenure)	n/a	100%	100%
• Gas	n/a	100%	100%
• Land Sale Bonuses	n/a	100%	100%

Sources: Oil and Oil Sands Royalty (Petroleum Registry of Alberta); Oil Sands Tenure and Land Sale Bonuses (Land Automated Mineral Agreement System – LAMAS); Gas (Mineral Revenues Information System – MRIS)

Discussion of Results

The Department of Energy's mandate is to collect the Crown's share of the resource on behalf of Albertans. This measure demonstrates the Department's system of checks, internal audits and processes in ensuring compliance and accuracy in calculating revenues owed.

Albertans benefit by knowing that a high level of assurance is maintained, Crown resource ownership is being well managed, and appropriate controls exist and are being executed. Through these systems and processes, the Department maintained 100% accuracy in the calculation of revenues owed in 2009.

Performance Measure:

2.b Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are fully collected

Target:

100 per cent of amounts owed are collected.

Results:

			Year Ending December 31
	Actual 2007	**Actual 2008**	**Last Actual 2009**
Revenues from Oil, Oil Sands, Gas, and Land Sale Bonuses are fully collected: Percentage of amounts collected compared to amounts owed			
• Oil	n/a	100%	100%
• Oil Sands (Royalty)	n/a	100%	100%
• Oil Sands (Tenure)	n/a	100%	100%
• Gas	n/a	100%	100%
• Land Sale Bonuses	n/a	100%	100%

Sources: Oil (Alberta Petroleum and Marketing Commission); Oil Sands Royalty and Gas (Corporate Accounting Revenue System – CARS); Oil Sands Tenure and Land Sale Bonuses (Land Automated Mineral Agreement System – LAMAS)

Discussion of Results

The Department of Energy's mandate is to collect the Crown's share of the resource on behalf of Albertans. This measure gauges the ability of the Department to collect payments owed through the development of Alberta's resources.

The Department issues invoices with the amount of royalty due and payable by a due date. Data reports are extracted to identify accounts past due. For accounts that are past due, a tiered level collection process is in place to collect unpaid royalty by the due date. Through the effective processes the Department has in place, 100 per cent of revenues owed in 2009 were successfully collected.

GOAL 3 **Linked to Core Business 1 – Assuring energy supply and benefits from energy and mineral resource development for Albertans**

Energy and mineral resource development occurs in a responsible, environmentally sustainable manner and supports the Government of Alberta outcomes

The *Provincial Energy Strategy* provides direction for addressing emerging energy and mineral trends. The Ministry is encouraging clean energy production and investment in future energy development in a manner that protects the environment and public safety while integrating broader considerations of social, economic, resource, environmental and cumulative effects.

Key Achievements

The New West Partnership Energy Memorandum of Understanding (MOU) was signed by Alberta, Saskatchewan and British Columbia on December 16, 2010. This collaborative framework builds upon existing New West Partnership activities by establishing a vehicle to collaboratively strengthen and expand the region's energy sector. The provinces' Energy Ministers agreed upon three actions including; a collaboration and information sharing initiative; development of a joint strategy on market diversification and development; and joint consultations with major petroleum and natural gas associations. Ongoing work will continue in 2011-2012.

Alberta Energy also initiated development of an Oil Market Diversification Strategy, which will focus on accessing and growing new markets for bitumen, synthetic crude oil and refined petroleum products. The Strategy will identify actions for the Government of Alberta to help achieve intermediate and long-term market diversification and development outcomes.

The Ministry participated in the first Heavy Oil Working Group, an initiative organized by Natural Resources Canada to bring together regional partners from various countries to share experiences with heavy oil, updates on the current state of technology, and to discuss environmental and policy issues involved with heavy oil development. Alberta Energy also participated in the 2010 Pacific NorthWest Economic Region Annual Summit and working groups – a forum for public and private sector leaders to address issues impacting our regional economy, including energy development and transmission.

Regulatory Enhancement Project (REP)

An MLA Task Force established in March 2010 led a comprehensive upstream oil and gas regulatory review to foster a modern, efficient, outcomes-based and competitive regulatory system that maintains the province's strong commitment to environmental management, public safety and resource conservation. Several meetings with representatives from industry, municipal government, First Nations, landowners and environmental non-governmental organizations wrapped up with a final multi-stakeholder meeting on October 1, 2010. Two rounds of an on-line survey were completed through the Regulatory Enhancement Project stakeholder website, and feedback reports were posted to the stakeholder website throughout the engagement process.

Released in December 2010, the *Enhancing Assurance, Report and Recommendations of the Regulatory Enhancement Task Force to the Minister of Energy* delivered six key recommendations for improving Alberta's regulatory system. Government accepted the report and recommendations are being implemented. The Department of Energy is leading the implementation efforts and established the REP Implementation Office. The accepted REP recommendations are being addressed and advanced by representatives from the departments of Energy, Environment and Sustainable Resource Development, and the Energy Resources Conservation Board.

Carbon Capture and Storage

In November 2010, Alberta became the first province in Canada to introduce comprehensive legislation for a greenhouse gas reduction strategy. This strategy will guide how large scale carbon capture and storage (CCS) projects proceed in Alberta. By using some of the captured CO_2 for enhanced oil recovery, Alberta is expected to double its conventional oil recovery, generating tens of billions of dollars in provincial royalties and taxes.

The *Carbon Capture and Storage Statutes Amendment Act, 2010* (Act) was passed in the fall 2010 session of the Alberta Legislature. This Act declares the Crown as the owner of pore space and authorizes the Crown to accept long-term liability associated with CCS. Additionally, the Act established a new *Post-Closure Stewardship Fund* to ensure resources are available to cover any costs related to the sequestration sites when the liability is transferred to the province, and a fund for ongoing monitoring costs and any required remediation.

Approval of four CCS projects which represent a diverse portfolio of capture technologies, industry sectors, project proponents and storage types and locations will situate Alberta as a global leader in this clean energy technology. When fully operational, these projects are expected to prevent the release of five million tonnes of carbon dioxide from entering the atmosphere each year starting in 2015, and clearly demonstrate Alberta's commitment to the responsible development of our energy industry and the reduction of our greenhouse gas emissions. By achieving significant reductions in greenhouse gas emissions, these projects also support Alberta's *Climate Change Strategy*. In addition, fostering clean energy production and the production of additional conventional light oil through enhanced oil recovery techniques aligns with government's *Provincial Energy Strategy*.

In March 2011, a review of the regulatory framework applied to the CCS *Regulatory Framework Assessment* (RFA) was launched. Participation in the regulatory framework assessment includes over 100 national and international CCS stakeholders and experts from industry, government, academia, research institutions and non-governmental organizations. A steering committee will oversee the assessment process, and an expert panel will advise on the scope and content of work. Issue-specific working groups will develop recommendations for a world-class regulatory framework for CCS in Alberta. This framework will provide clarity for operators on requirements and assurance to the public that CCS projects in Alberta will be operated in an efficient, safe and responsible manner. Consultation with stakeholders and Albertans to obtain input on the work undertaken is planned for fall 2011.

Other developments include establishment of a cross-ministry team to develop guidelines for allowing the development of wind power on public lands. There have also been amendments to the Transmission Regulation which require the Alberta Electric System Operator to construct transmission to areas of renewable or low emission electricity. As well, a Southern Alberta Transmission Reinforcement project, currently under development, will allow for the connection of up to 2,700 megawatts of additional wind generation in the region.

Land-use Framework

Government's *Land-use Framework* sets out an approach to manage public and private land and natural resources to achieve Alberta's long-term economic, environmental, and social goals. Providing a 'blueprint' for land-use management and decision-making, this Framework played a crucial role in development of the Lower Athabasca and South Saskatchewan Regional Plans.

Energy contributed policy and technical analysis and research on issues relating to energy and mineral development, conservation and biodiversity, and air and water management frameworks. The Ministry also led a review of the type and way information is provided on surface and environmental access restrictions prior to the public offering of Crown mineral rights. Ensuring information continues to be readily and easily accessible to industry and the public will support implementation of the *Regulatory Enhancement Project* as well as the outcomes and objectives defined in regional plans.

Through extensive dialogue with industry and other Alberta Government ministries during the *Mature Oilfield Review*, Alberta Energy articulated a policy foundation recognizing conventional oil development as a multi-decade opportunity for Alberta. Incremental oil production through enhanced oil recovery can lead to increased recoverable reserves and incremental royalties for the Crown. Working with industry, a review of the *Enhanced Oil Recovery Royalty Relief Program* was undertaken to ensure the program is appropriately positioned in this policy context. Program recommendations have been developed as a result of the review.

The Department also continued to participate in various initiatives such as Water for Life, species at risk policy, and cumulative effects management. Support to these integrated approaches and innovative solutions will help ensure reasonable levels of access, and promote environmentally responsible energy and minerals development. Energy continued to engage other departments through the Shale Gas Committee to ensure coordination and collaboration among related policy and regulatory initiatives. Continued engagement in policy and regulatory activities, along with other ministries, will have the potential to impact the development of unconventional gas resources.

Performance Measure:

3.a Carbon Capture and Storage

Target:

Storage of five million tonnes of CO_2 annually by 2015.

Results:

			Year Ending December 31
	Actual 2008	**Actual 2009**	**Last Actual 2010**
Carbon Capture and Storage: Report annual capture and injection of carbon in Alberta[1]	N/A	N/A	N/A

Source: Following the execution of the funding agreements of the projects selected, the data sources available will be investigated for accuracy and applicability for this business goal.

Note:

[1] This data is currently being collected by the ERCB and Alberta Environment.

Discussion of Results

Currently the projects selected for funding are expected to be operating by 2015, therefore no carbon dioxide has yet been stored by these projects.

Performance Measure:

3.b Upstream Oil and Gas Industry Investment

Target:

Annual industry investment in the upstream oil and gas industry will be in the $23 to $30 billion range.

Results:

			Year Ending December 31
	Actual 2007	**Actual 2008**	**Last Actual 2009**
Upstream Oil and Gas Industry Investment: Upstream industry investment in Alberta – Annual capital expenditure in Alberta on exploration and development of oil, oil sands and gas resources[1] ($ billions)	37.7	40.1	21.6

Source: Statistics Canada's Private and Public Investment (PPI) publication

Note:

[1] The Private and Public Investment publication is reported two years behind. The results of this measure do not include bonuses from the sale of mineral rights.

Discussion of Results

Continued investment in Alberta's energy sector demonstrates the competitiveness and attractiveness of resource development in Alberta. During the 2009 calendar year, Alberta faced a drastic reduction in upstream oil and gas investment, primarily influenced by the global economic recession and subsequent collapse in oil prices. As a result, total upstream oil and gas industry investment in Alberta fell to $21.6 billion in 2009, which represented a 46% drop in investment from 2008 levels. While conventional oil and gas investment declined by 43 per cent in 2009 to $11.0 billion from $19.4 billion in 2008, this result was coupled with investment in the oil sands falling to $10.6 billion in 2009, a 49 per cent decrease from the 2008 level of $20.7 billion.

While industry investment is driven largely by commodity prices over which the Department has no control, the government has the ability to influence industry's decisions to invest in Alberta through the royalty and tax regime, approval processes, land and market access, and the regulatory environment. The government fosters an investment environment through a competitive tax and royalty regime, which over the long term, encourages continued development of Alberta's energy resources.

Albertans benefit from industry investment through jobs, business opportunities, taxes paid to all levels of government and resource revenues, which are used to fund a variety of projects and programs including health and education.

Bonuses from Crown Leases are amounts collected by the government, but do not represent an infusion of investment into the private sector or industry. The intent of the measure is to gauge Investment in Alberta's energy sector, and not revenue amounts collected by government, so these amounts are excluded from calculations.

GOAL 4 **Linked to Core Business 1 – Assuring energy supply and benefits from energy and mineral resource development for Albertans**

The Ministry and its partners have the required policies and programs to encourage value-added development in Alberta

Alberta currently has a world-class petrochemical industry, and can achieve additional benefits by upgrading energy resources into higher value commodities and products. The oil sands, when combined with Alberta's ethane-based petrochemical industry, create significant potential for more value-added development in Alberta. The ministry, partner departments, and interested parties will collaborate to shape a value-added strategy for Alberta, one of the key directions in the *Provincial Energy Strategy.*

Key Achievements

Successful negotiation of a Memorandum of Understanding with North West Upgrading (NWU) will advance upgrading and refining of bitumen in Alberta, increase supplies of diesel fuel and enhance Alberta's position as a secure supplier of clean energy. The first project with the North West Redwater Partnership (which includes NWU and Canadian Natural Resources Limited) will lead to construction of a new bitumen refinery in Alberta's Industrial Heartland, northeast of Edmonton. The refinery will process 50,000 barrels per day of bitumen in 2014, of which 37,500 barrels per day will be Crown bitumen.

Through Bill 1, the *Alberta Competitiveness Act*, the province worked with industry, business leaders and Albertans in progressing the shared goal of making our province one of the most competitive jurisdictions in the world. By coordinating efforts, Energy, Finance and Enterprise and Alberta Innovates will develop strategies to enhance Alberta's competitiveness for the long-term benefit of Alberta.

A five-year extension and expansion to the *Bioenergy Producer Credit Program* was approved in March 2010. The expansion incorporates additional bioenergy production from a variety of agricultural, forestry and municipal waste streams to the March 2016 extension period. Examples of waste-to-bioenergy products supported under this program include biogas from manure, landfill gas, ethanol from municipal and wood waste, combustion of pulp mill and sawmill waste for electricity and heat, and waste heat recovery from bioenergy operations. Three of the six facilities which received producer credits under the program ending March 31, 2011 produced bioenergy from waste; one using manure and two using wood waste. This was the final year of the five-year bioenergy grant programs supporting development of bioenergy capacity, infrastructure and markets. During this fiscal reporting period, $4.5 million was awarded in grants to support seven bioenergy projects including four waste to energy projects.

The *Incremental Ethane Extraction Program* was extended and amended to help address feedstock supply issues. Initially designed to encourage extraction of ethane from natural gas, the amendments will help encourage more ethane extraction from off-gases that result from bitumen upgrading or refining. In addition to creating a new source of feedstocks, capture of off-gases provides diverse feedstocks for new petrochemicals and environmental benefits during oil sands processing. The Program changes encourage industry to make the large capital investments in Alberta required to increase the supply of feedstock for our petrochemical industry.

Performance Measure:

4.a Ethane Demand in Alberta

Target:

60,000 – 85,000 additional barrels of ethane extracted per day over the next five years[1].

Results:

	Year Ending December 31		
	Actual 2008	**Actual 2009**	**Last Actual 2010**
Ethane Demand in Alberta – in barrels per day[2]	223,000	222,000	216,600

Source: ERCB ST-98, 2011

Notes:

[1] Additional production above forecasted Ethane Consumption Baseline data by the end of the Incremental Ethane Extraction Program. For more detailed information, see the "Performance Measure Methodologies" section in Appendix A.

[2] Includes small volumes used for enhanced oil recovery.

Discussion of Results

Ethane is recovered mainly from the processing of natural gas. Gas processing plants in the field extract ethane along with propane, butanes, and pentanes plus as products or recover a Natural Gas Liquids (NGL) mix from raw gas production. NGL mixes are sent from these field plants to fractionation plants for the recovery of individual NGL specification products. Straddle plants recover NGL products from gas processed in the field.

All of the specification ethane extracted in 2010 was used in Alberta as feedstock to the extent that supply equalled demand. About 63 per cent of total ethane in the gas stream was extracted, while the remainder was left in the gas stream and sold for its heating value. This is compared to 56 per cent of the available ethane being extracted in 2009.

The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline allows for a range of feedstocks to be transported from Fort Saskatchewan to Joffre. These feedstocks supplement the ethane supplies now used at the petrochemical plants at Joffre, where three of the four ethylene plants are located. The fourth is located in Fort Saskatchewan.

Some of the issues that have kept ethane production low throughout 2009 and 2010 were:

- Pipeline tolls for transporting natural gas
- Continuing surplus of low cost gas (including the emergence of low cost shale gas plays)
- New demand in Alberta is intra-provincial

Nonetheless, the Alberta ethylene industry has maintained its historical cost advantage for ethylene production compared to a typical ethane/propane cracker in the U.S. Gulf Coast.

Performance Measure:

4.b Ethanol Production in Alberta

Target:

150 to 300 million litres.

Results:

	Year Ending December 31		
	Actual 2008	Actual 2009	Last Actual 2010
Ethanol Production in Alberta – millions of litres	40	40	40

Source: Alberta Department of Energy.

Discussion of Results

Ethanol is usually derived from corn and grain, and can be blended with gasoline to be used as a fuel. Ethanol is clean burning and may improve fuel economy. As emerging technologies (“second generation technologies”) come into commercial use, ethanol will be produced from woody materials, agricultural waste, municipal solid waste and non food crops. These technologies will help create value from Alberta’s 20 million tonnes of annual waste production. Waste forest biomass such as forest slash, forest mill waste, and trees destroyed by the mountain pine beetle are of particular interest to future ethanol producers.

Three grant programs were introduced under the Nine-Point Bioenergy Plan in support of government’s commitment to the advancement of renewable fuels and bioenergy in Alberta. To monitor the outcomes of these programs, the Department of Energy tracks ethanol and biodiesel production in Alberta. Two programs, the Biorefining, Commercialization and Market Development Program (BCMDP) and the Bioenergy Infrastructure Development Program (BIDP) concluded in March 2011. Over $150 million in grants were awarded to bioenergy projects over the past five years. The Bioenergy Producer Credit Program (BPCP) was expanded and extended to 2016 to provide continued support for bioenergy production.

The Alberta government passed the Renewable Fuels Standard (RFS) Regulation in March 2010. This includes a requirement for an average annual blend of five per cent renewable alcohol (mainly ethanol) in gasoline sold in Alberta, starting in April 2011. To ensure the RFS environmental objectives are met, biofuels used to meet Alberta’s RFS must, on a life cycle basis, demonstrate 25 per cent fewer greenhouse gas emissions than equivalent fossil fuel.

Increasing Alberta’s bioenergy (ethanol and biodiesel) production capacity supports the Provincial Energy Strategy outcomes of Clean Energy Production and Sustained Economic Prosperity. Bioenergy production helps to reduce our reliance on fossil fuels by increasing the use of renewable energy sources, while supporting the economic sustainability of regions that are rich in biomass. Increasing bioenergy production also contributes to Greening Energy Production, as outlined in the Climate Change Emissions Strategy.

Annual results reported for ethanol and biodiesel (performance measure 4.c) are for current plant capacity, not actual production. Annual production statistics from the two existing biofuel plants (one ethanol and one biodiesel) are confidential. When the number of plants in Alberta is sufficient to protect commercial information, total production numbers may be reported. Permolex Limited currently has a capacity of 40 million litres per year.

Based on ethanol facilities proposed in Alberta under the bioenergy grant programs, Alberta has the potential to achieve over 800 million litres of production capacity by 2015. Uncertainties around achieving this level of capacity include industry decisions to proceed with proposed projects and timing of advancement of second generation technologies.

Performance Measure:

4.c Biodiesel Production in Alberta

Target:

55 to 110 million litres.

Results:

			Year Ending December 31
	Actual 2008	**Actual 2009**	**Last Actual 2010**
Biodiesel Production in Alberta – millions of litres	19	19	19

Source: Alberta Department of Energy

Discussion of Results

Biodiesel is a renewable fuel derived from organic substances, such as vegetable oil or animal fats. It can be blended with petroleum-based diesels and has been shown to significantly reduce emissions.

The three programs under the Nine-Point Bioenergy Plan also support biodiesel production.

The Renewable Fuels Standard (RFS) includes a requirement for an average annual blend of two per cent biodiesel from renewable sources in diesel fuel sold in Alberta, starting in April 2011. Up to 132 million litres of biodiesel may be required to meet Alberta's RFS, based on estimates of Alberta consuming 6.6 billion litres of diesel fuel per year.

At the end of the fiscal year, Western Biodiesel was the only commercial biodiesel production plant in Alberta, with a capacity of 19 million litres.

Based on the abundance of biodiesel feedstock that can be utilized with existing biodiesel production technology, Alberta could produce 700 million litres of biodiesel per year by 2015 if all known proposed projects were to be implemented.

GOAL 5 **Linked to Core Business 2 – Leading and engaging citizens, communities, industry and governments to achieve effective stewardship of Alberta's energy resources**

Albertans are aware of and understand existing and emerging trends and opportunities relating to energy development and use in Alberta

The focus of this goal is to enhance understanding of changing energy trends, new energy sources and issues related to the development of energy, as well as improving awareness around how the province develops and uses energy, its economic benefits, and environmental protection measures.

Key Achievements

Alberta Energy is at the forefront of the Government of Alberta's international energy-related engagement and advocacy efforts. Our focus evolved from sharing accurate information on our energy development to an expanded dialogue highlighting Alberta's clean energy story. This dialogue has showcased Alberta's front and centre effort to improve the manner in which fossil fuels are developed and used. In this endeavour, the Department of Energy worked closely with other ministries to promote increased national and international awareness. In addition, Alberta Energy has developed a stronger relationship its federal counterparts.

The Department fostered an international understanding of Alberta's secure and reliable energy supply and the critical role the province's energy sector has played in North American economic recovery and growth. This includes identifying and highlighting the extensive supply-chain manufacturing that feeds into Alberta's oil sands industry, and as a result provides economic benefits throughout North America. We are also advancing diversification of future energy markets to include Asia as well as our traditional energy customer, the United States.

A concerted effort has been made by government and the Department to address misinformation on how the province develops its energy resources. We have been involved in over 25 incoming international missions, over 25 outgoing national and international missions involving elected officials and/or senior public service representatives, and over 10 energy events/conferences/meetings involving international audiences. As a result of Alberta Energy's international engagement and advocacy initiatives, a better informed debate exists outside our boundaries.

Adjustments to Alberta's fiscal framework and a series of stakeholder engagements around making regulation of Alberta's energy sector more efficient and effective were often highlighted. However, there were many more issues that impacted energy development in Alberta during this reporting period, including value-added development and continued lessening of the environmental footprint of resource development.

The last year also saw two major agreements finalized to forward two of Alberta Energy's ongoing priorities: to see more value-added development of the province's resources and to advance industrial-scale carbon capture and storage. The agreement to pursue a bitumen refinery in the Industrial Heartland that will be fully CCS operational will enhance Alberta's position as a world leader in clean energy development. A second agreement to construct a backbone carbon dioxide trunk line from the Industrial Heartland to mature conventional oilfields in central Alberta will decrease industrial carbon dioxide emissions while increasing recoveries and therefore royalty revenues from the oilfields.

Alberta Energy hosted an investor webinar to help those who invest in Alberta's energy sector understand new royalty information, and to aid them in making go-forward investment decisions. Each year, Energy also updates an online document titled Energy Economics, which reviews Alberta's resource and royalty information with comparable information from other jurisdictions. An Energy Update document is posted monthly to provide a summary of various oil, natural gas and gasoline wholesale and retail prices in Alberta and in comparative jurisdictions.

The Alberta Energy website is regularly updated with new information and data to help Albertans have convenient access to data and to better understand a wide range of energy-related topics. Additionally, the website was updated to include unique online mouse-over glossary, a feature allowing users to highlight technical terms then press *Ctrl-Y* to view an explanation of the term.

Performance Measure:

5.a Albertans' Assessment of their Energy Knowledge

Target:

To increase Albertans' assessment of their knowledge of the energy industry in Alberta from 70 per cent to 71 per cent by 2011-2012.

Results:

			Year Ending December 31
	Actual 2009	**Actual 2010**	**Last Actual 2011**
Albertans' Assessment of their Energy Knowledge	70%	n/a[1]	63%

Source: 2011 Omni Alberta Survey

Notes:

[1] This survey is conducted every second year (biennially).

Discussion of Results

This performance measure was developed to support the implementation of the *Provincial Energy Strategy* and to bolster knowledge, awareness and education on energy issues.

Results indicate that 63 per cent of Albertans rate themselves from knowledgeable to very knowledgeable about the energy industry in Alberta (survey categories 4, 5, 6, and 7). The 2011 actual results were eight per cent below the 2011-12 Business Plan target of 71 per cent.

Although there are several complex factors that influence how Albertans rate their knowledge of the energy industry, possible variables affecting the 2011 results may include: vulnerabilities in a distortion of results due to conflicting energy news media stories; energy issues may be perceived by Albertans as very technical or complex information; and Albertans may be developing an awareness that there is much to know about Alberta's energy industry and consequently may becoming more realistic about "what they really know."

GOAL 6 Linked to Core Business 2 – Leading and engaging citizens, communities, industry and governments to achieve effective stewardship of Alberta's energy resources

Industry, citizens, and communities conserve and use energy wisely

Managing energy efficiency and conservation helps mitigate rising energy costs and environmental impact; while investments in energy efficiency and conservation reduce the energy intensity per dollar of GDP. The ministry works with other ministries, municipalities and industry to achieve the significant benefits of a lessened impact on the environment, reduced costs to residents, improved industry competitiveness, and new innovation.

Key Achievements

The Ministry continued to lead a government-industry committee identifying fuel gas efficiencies in upstream oil and gas processing. Industry committee members undertook workshops related to Best Management Practices developed by the Fuel Gas Efficiency Committee, and Energy supported an oil sands energy efficiency assessment of an operating Steam Assisted Gravity Drainage facility. The final report, completed in December 2010, identified opportunities that could result in savings of total energy consumption, carbon dioxide emissions, and energy costs.

Alberta Finance and Enterprise, Alberta Environment and Alberta Energy jointly developed a suite of resources for small- to medium-sized enterprises in the manufacturing sector to increase the adoption of energy efficiency best practices. This included an on-line toolkit providing immediate connections to guides and resources, delivery of workshops in partnership with Natural Resources Canada informing Alberta industry about these energy efficiency opportunities, and an energy efficiency assessment program to assist in developing a business case for adoption of the best practices. The Deputy Ministers of Energy, Environment and other ministries are engaged in the development of a policy framework with Environment leading energy efficiency and conservation actions.

Performance Measure:

6.a Increased Fuel Gas Efficiency Reporting

Target:

To increase the number of industry participants who voluntarily report fuel gas efficiency information.

Results:

	Year Ending December 31		
	Actual 2007	**Actual 2008**	**Last Actual 2009**
Increased Fuel Gas Efficiency Reporting: Percentage of total fuel gas used by industry participants who voluntarily reported fuel gas efficiency information	n/a	n/a	68%[1]

Source: Energy Resources Conservation Board

Notes:

[1] Results are reported biennially.

Discussion of Results

Total fuel gas consumption, which may be defined as the part of the produced natural gas consumed by operations in the production, transportation and processing of natural gas from the wellhead to the sales line, is increasing. Even a moderate reduction in fuel gas consumption could translate in savings of millions of dollars. Improved management of fuel gas efficiency would help address issues of environmental impacts and increase industry competitiveness, as well as extend both the life of the facilities and the oil and gas industry in Alberta. Fuel gas optimization by industry is not a regulatory or legislative requirement. The use of voluntary reporting is a first step to assist industry and government in identifying fuel gas efficiency opportunities. Voluntary reporting of the top fuel gas users' consumption of fuel gas will be a proxy of how successful industry can be in proactively improving efficiencies.

In 2009, the Ministry began conducting biennial surveys of the 15 largest fuel gas users, which represented 68 per cent of fuel gas usage in the province. With the next scheduled survey to be conducted in 2011, the Ministry intends that more companies will become aware of their costs of fuel gas, which will then lead to greater efforts to manage fuel gas consumption.

The Fuel Gas Efficiency Committee with representation by government and industry is working on developing benchmarks for fuel gas use, which could ultimately lead to a change in methodology in the future.

GOAL 7 **Linked to Core Business 3 – Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems**

Energy related infrastructure is built and sustained to support the Government of Alberta's objectives

Alberta's electricity system requires a robust, reliable and efficient transmission system 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. Energy works with other ministries to encourage development of energy infrastructure and broader social/community infrastructure in support of future economic prosperity.

Key Achievements

A number of important infrastructure initiatives have been initiated or progressed during this reporting period. In March 2011, Alberta announced commencement of the Regulatory Framework Assessment (RFA) to ensure Alberta has a world class regulatory regime in support of safe and responsible development of carbon capture and storage. The RFA will develop recommendations to refine and guide legislation and regulations regarding implementation of CCS in Alberta. Passed primarily to address issues of long-term liability and pore space access, the *Carbon Capture and Storage Statutes Amendment Act* (CCSSAA) also established a new industry supported *Post-Closure Stewardship Fund* to cover the costs associated with government assuming the long-term liability of storage sites.

The Transmission Regulation was amended to give effect to many provisions contained in the *Electric Statutes Amendment Act*, 2009 and require the Alberta Electric System Operator to construct transmission to areas of renewable or low emission electricity. The Government of Alberta is working with the Alberta Electric System Operator to ensure policies and procedures are in place to support the development of interties. Barriers and opportunities for distributed generation are considerations in development of the *Alternative and Renewable Energy Policy Framework*.

Performance Measure:

7.a Magnitude of Transmission Must Run (TMR) Congestion (GWh); Magnitude of Constrained Down Generation (GWh); Transmission Losses (%)

Target:

To show improvement year over year. In specific, for the transmission measure, improvement is indicated by a reduction in numbers.

Results:

	Actual 2007	Actual 2008	Year Ending December 31 Last Actual 2009
Magnitude of Transmission Must Run (TMR) Congestion (GWh)	n/a	1,005	792
Magnitude of Constrained Down Generation (GWh)	n/a	295	55
Transmission Losses (%)	n/a	3.8%	3.6%

Source: AESO

Discussion of Results

Electricity is a facilitator of economic development in Alberta. A robust, reliable and efficient electricity transmission system is required to ensure electricity can be delivered where and when it is needed. By ensuring development of a robust transmission system, generation developers will know that they will be able to efficiently move their product to market. In turn, they will have confidence to develop new generation ensuring an adequate, reliable supply of electricity to Albertans. Until transmission is improved, potential renewable or low-emission electricity generation in Alberta will remain constrained by location. There are hydroelectric resources in the north, wind and solar in the south, and biomass in the northwest. Optimal use of power from these sources depends on our ability to bring it to where it is needed.

A robust transmission system that allows generators to efficiently deliver their product to market must not have any congestion during normal operation. Transmission Must Run and Constrained Down Generation are measures that indicate the level of congestion on the system. As critical transmission projects and other regional transmission projects are completed over the next ten years it is expected that these indicators will trend toward zero. However, there will always be some instances of abnormal operation during which Transmission Must Run generation must be used or some generation must be constrained from operating at full capacity.

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. Transmission losses are expected to continue on a downward trend as major transmission projects are completed over the next decade.

Performance Measure:

7.b Number of Micro-generation Sites

Target:

To show continuous improvement in the number of micro-generation sites year over year.

Results:

	Actual 2008	Actual 2009	Year Ending December 31 Last Actual 2010
Number of Micro-generation Sites	41	122[1]	216

Source: AESO

Notes:

[1] Data reported in the 2010-13 Business Plan was only for results up to September 30, 2009. The Actual total for 2009 has been revised to reflect the full year's results.

Discussion of Results

Alberta has continued to see steady growth in the installation of micro-generation systems. The development of micro-generation helps meet Alberta's objective of developing clean energy, simultaneously fostering economic development and reducing pollution from electricity generation. In addition, micro-generation builds on Alberta's success in fostering market-based innovation by increasing the options available to Albertans for obtaining their electricity. Total installed capacity grew from 0.4 megawatts in December 2009 to 0.7 megawatts in December 2010. Micro-generators generated 172 megawatt-hours (MWh) in 2010 up from 106 MWh in 2009. Solar systems accounted for two thirds of the systems installed with small wind generators making up most of the remainder. A review of the micro-generation regulation was originally intended to be triggered when the 300 installed system threshold is crossed which is expected to take place later in 2011.

GOAL 8 **Linked to Core Business 3 – Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems**

Promote effective innovation policies and programs to achieve technology and processing improvements in the development of energy and mineral resources

Technology is important to realizing our energy vision and outcomes of the *Provincial Energy Strategy*. New technologies, along with enhanced deployment of proven technologies, will reduce emissions, development costs, and reduce the use of natural gas and water in energy development, while realizing large scale carbon capture, increased recovery, and expansion of Alberta's renewable energy sources. The Ministry will work with Alberta Advanced Education and Technology and other stakeholders to support and encourage energy research by industry, government, universities and research organizations.

Key Achievements

Energy worked with ministries across government to coordinate and develop a strategic approach to research. Consultation with relevant ministries and corporations centred around the development of a strategic research plan to provide research direction not only within Energy, but to government as a whole. Our ministry was an active participant in the implementation and work of the new Innovation Framework, led by Advanced Education and Technology as well as the work of the Alberta Research and Innovation Authority. The new Alberta Innovates Corporations, specifically Alberta Innovates - Energy and Environment Solutions and Alberta Innovates - Technology Futures were also important engagement partners.

The Ministry continued to work with research organizations and industry through provision of funding and technical support to numerous committees and organizations, including the Petroleum Technology Alliance of Canada (PTAC), Cambridge Energy Research Associates, Canadian Energy Research Institute (CERI), and others. This work allowed policy insight to be provided to industry, helping focus the research being undertaken and drive innovation in the energy sector. Further encouragement and support to industry research was demonstrated through participation in projects such as the Industry Tailings and the Tailings Road Map project, the Clean Bitumen Technology Action Plan led by PTAC, the Gas Over Bitumen Technical Committee and tailings research.

Support to research in industry also continued through the Innovative Energy Technologies Program (IETP). The IETP provides royalty allowances for field pilots that use innovative technologies in oil, oil sands, and gas production, including projects providing a technical solution to the Gas over Bitumen issue. In this past fiscal year, over $11 million in new royalty allowances were granted for a total to date under the program of $109 million for 32 projects. A fifth round of funding was approved and projects finalized. A regulatory amendment was passed which will allow for another round of funding in the 2011-2012 fiscal year and expansion of the program to include oil sands mining projects, including tailings research.

Performance Measure:
8.a Data Accessibility

Target:
In order to support innovative research, the target is to have 90 per cent of facilitated research placed in a Department repository, with public access wherever possible. Over the course of three years, the target is to capture 95 per cent of research, with the long term goal to capture 100 per cent.

Results:

			Year Ending December 31
	Actual 2007	Actual 2008	Last Actual 2009
Data Accessibility: Percentage of Department facilitated research documents filed in a research repository, with public access wherever possible	n/a	n/a	n/a

Source: Department of Energy

Discussion of Results
The development and implementation of the research repository is currently underway. It is expected to be completed in the first quarter of 2011-12, with the results for calendar year 2010 to form the baseline data. As long as the implementation proceeds as planned, a target of 90% will be achieved this year. However, if implementation is delayed, the results could be swayed. Results from 2011 will be the first with the database completed and functioning.

The database is being developed in two stages. The first stage of the database is Department of Energy access and the second stage will provide public access. The current focus is on stage one, with the second stage being developed in 2012. The repository is being developed to follow the Department's Information Management Security Classification Guideline.

GOAL 9 **Linked to Core Business 3 – Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems**

Alberta has a competitive and efficient energy system ensuring Albertans electricity and natural gas needs are met

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

Key Achievements

Reliable delivery of electricity to all consumers, including monitoring and oversight is required to ensure effective market operation. To this end, Alberta Energy established a framework for responsibility of industry-led investment in electricity infrastructure and markets. The *Electricity Coordinating Forum* was created, allowing stakeholders the ability to identify policy concerns impacting the ongoing development of Alberta's electric system.

The Western Electricity Coordinating Council is the regional entity responsible for coordinating electric system reliability in the Western Interconnection that extends from Canada to Mexico. A specific identifiable reliability requirement set by the Council is a seven per cent margin which has been maintained by Alberta's wholesale market. This calculation demonstrates that Alberta maintains a sufficient margin between firm electricity generating capacity and peak demand, and is one of the Ministry's key performance measures.

In March 2010, the Government of Alberta directed the Alberta Utilities Commission (AUC) to inquire into and report on how smart grid technology can be used to modernize Alberta's electricity system. The AUC completed its inquiry and found that Alberta has already made significant progress in the deployment of smart grid technologies.

Energy also publishes monthly switching statistics on its website. The switching statistic rate measures the net movement of customers from the regulated rate to competitive contracts in the retail market. Development of a consistent set of standards is essential for maintaining and improving the reliability of the North American transmission grid.

The Federal-Provincial-Territorial Electricity Working Group and the Trilateral Electricity Reliability Organization are the main forums for national and international collaboration on transmission reliability and security issues. Energy participates in and supports the ongoing activities of both the Federal-Provincial-Territorial Electricity Working Group and the Trilateral Electricity Reliability Organization to ensure that Alberta's interests are understood and considered.

The North American Electric Reliability Council, recognized by the Government of Alberta as the Electric Reliability Organization, has approved over 120 standards, of which 34 have been adopted for use in Alberta. Another 41 were not applicable for use in Alberta.

Performance Measure:

9.a Power Generation

Target:

Maintain a minimum 7 per cent margin over peak demand.

Results:

	Actual 2008	Actual 2009	Last Actual 2010
			Year Ending December 31
Power Generation: Margin (MW) between Firm Generating Capacity[1] and Peak Demand	20%[2]	18%[2]	17%

Sources: Energy Resources Conservation Board (ERCB), Alberta Electric System Operator (AESO) and Alberta Department of Energy.

Notes:

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

[1] The 2010-13 Business Plan details this performance measure as the 'Margin (MW) between supply and peak demand.' Due to a methodology improvement in 2010, the Ministry started to report Firm Generating Capacity instead of supply for the 2009-10 Annual Report and beyond. Firm Generating Capacity provides a more accurate margin, as it 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.**

[2] Data has been revised from results reported in the 2010-13 Business Plan due to the above change in methodology (see "Performance Measures Methodology" section in Appendix A).

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.

For 2010, the margin between the firm electricity generating capacity and peak demand has decreased to 17 per cent from the 2009 level of 18 per cent. This highlights the fact that Alberta's competitive market framework has successfully performed above the operating safety margin, resulting in robust competition in the wholesale market to the benefit of all consumers. It is important to keep in mind that annual variations in the margin are normal due to the change in peak demand and timing of new generation additions.

Firm electricity generating capacity has been calculated at 11,963 megawatts (MW) for 2010. Peak demand in the winter period of the climatic year (October 1, 2010 to March 31, 2011) was 10,226 MW and was within 10 MW (or 0.1 per cent) of the all time high record set in 2009.

GOAL 10 **Linked to Core Business 3 – Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems**

Regulation of energy and utility development in Alberta is fair, responsible and in the public interest

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.

The ERCB regulates the discovery, development and delivery of Alberta's energy resources, including oil, natural gas, oil sands, coal, and pipelines. Regulation is needed so non-renewable resources are produced in a safe, responsible, and efficient manner. The ERCB also ensures that development takes place in the public interest, having regard for social, economic and environmental impacts, including resource conservation. The ERCB consistently re-examines its regulatory requirements and improves them wherever needed by engaging its stakeholders. As the development of Alberta's unconventional and newer resources is growing, the ERCB will be proactive in identifying and addressing emerging issues while continuing to deliver effective regulation.

The AUC makes 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 has rule-making responsibility related to data communications transactions and the delivery of these transactions to market participants to ensure well-functioning electricity and natural gas markets.

Key Achievements

The ERCB created the Stakeholder Engagement Office, a small, centralized team connected to a larger community of ERCB staff who regularly interface with stakeholders. The Stakeholder Engagement Office is responsible for understanding stakeholder needs and concerns, and relaying them within the ERCB for consideration; also provides strategic advice, guidance and coordination related to stakeholder engagement.

As well, the ERCB initiated a committee comprising the three western provinces (British Columbia Oil and Gas Commission and Saskatchewan Energy and Resources) to discuss a cross-jurisdictional approach to liability management and enforcement in the three provinces. This committee aligns with the Government of Alberta's commitment to the harmonization of upstream oil and gas regulation.

New processes were implemented to enhance the ability of parties potentially impacted by the Heartland project, and other interested parties, to participate in the proceeding. These enhancements include the ability to register prior to the AUC receiving the application, advanced decisions regarding standing, a process meeting shortly after the application was filed with the AUC, and options for parties wishing to participate in the proceeding (i.e. full participation in the oral hearing, presentation at a community hearing session, written submission). These process enhancements were also introduced into the three other critical infrastructure project applications.

The AUC also completed reviews of facility application processes related to the letter of enquiry process for minor alterations to transmission, distribution and power plant facilities, and revisions to AUC Rule 012 – Noise Control, which included possible streamlining of the requirements related to transmission substations (less than 240/260 kV) and to small power plants (less than 1 MW). These process improvements were approved for implementation early in the 2011-12 fiscal year.

The ERCB reviewed and granted approval—with conditions—to each of the eight tailings plans submitted by all oil sands mining operators, as required by *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. Collectively the operators have committed more than $4 billion in technology, infrastructure, and upgrades to meet the regulatory requirements of *Directive 074*. Over the life of the tailings plans projects, tailings reduction at those sites will exceed *Directive 074* requirements.

The ERCB issued the following:

- *Bulletin 2010-39: Invitation for Feedback on Province-Wide Framework for Well Spacing for Conventional and Unconventional Oil and Gas Reservoirs,* which relates to downhole spacing requirements. The ERCB continues to update requirements for the orderly and efficient development of the province's resources, while maintaining landowner rights and mitigating surface impacts.
- *Bulletin 2010-44: Enhancing the ERCB Role in Energy Technology Development* that will see innovative technology reviewed and deployed in a streamlined manner. While the ERCB does not prescribe or mandate which technology should be used, it continues to assess and support the deployment of innovative technologies as long as the technology meets the ERCB's mandate related to public safety, environmental stewardship and resource conservation.
- *Directive 078: Regulatory Application Process for Modifications to Commercial In Situ Oil Sands Projects*, which redesigns the regulatory approach to amendment applications for all commercial in situ oil sands projects. Commercial in situ oil sands projects typically take years to construct and operate for several decades; as technology changes and operational experience grows, the ERCB will receive multiple amendment applications from each in situ project. The new directive streamlines the amendment application process by employing one of three regulatory categories, depending on the nature and complexity of the amendment.
- Bulletin 2010-22 ERCB Processes Related to Carbon Capture and Storage (CCS) Projects, which informs industry stakeholders that the ERCB is using existing requirements to regulate CCS schemes. The ERCB has been regulating the disposal, storage, and injection of carbon dioxide (CO_2) for more than 20 years and has processes in place to provide for the effective regulation of these activities, including the more than 50 schemes involving CO_2 currently operating in Alberta.

Performance Measure:

10.a Regulatory Noncompliance

Target:

Less than or equal to 3.0 per cent of field inspections finding High Risk regulatory noncompliance.

Results:

	Year Ending December 31		
	Actual 2008	**Actual 2009**	**Last Actual 2010**
Protection of Public Safety: Percentage of field inspections finding High Risk regulatory noncompliance	2.1%	1.7%	1.7 %

Source:

Field Surveillance Inspection System database and Energy Resources Conservation Board Waste Plant Spreadsheet, March 2011.

Discussion of Results

In calendar year 2010, there were 14,345 initial inspections. Of these inspections, 239 found High Risk noncompliances, 100 relating to pipelines.

The ERCB has adopted a risk-based inspection strategy and is now focusing on higher value inspection work based on defined risk criteria. The ERCB has increased resources to frontline field operations enabling the ERCB to focus on continuing to educate industry through presentations and operator awareness sessions. This is ensuring that industry operations staff better understand regulatory requirements. In addition, heightened accountability continues by industry as a result of the monthly publication of *ST108* on the ERCB web site of High Risk enforcement actions.

Performance Measure:

10.b 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.

Results:

Year Ending December 31

	Actual 2008	Actual 2009	Last Actual 2010
Timeliness of the Needs and Facility Applications – Percentage of needs and facility applications determined within 180 days of the application being deemed complete	100%	92%[1]	100%

Source: Alberta Utilities Commission

Notes:

[1] The 2009 actual was revised from 97.8% to 92% 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.

Discussion of Results

In accordance with standards established in Alberta law, the AUC when considering an application for an approval, permit or license 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 2010, the AUC met this standard 100 per cent of the time. All 71 decisions were issued within the 180 day timeline.

GOAL 11 **Linked to Core Business 3 – Leading and supporting the development of energy related infrastructure, innovation, markets and regulatory systems**

Build an organizational environment for success

Sustaining and building organizational capacity is fundamental to ministry effectiveness. To effectively position Energy to respond to current and evolving business requirements, this goal focuses on having the right resources, people, finances, information, technology, processes and tools in place.

Key Achievements

To help address fiscal challenges outlined in Budget 2010, Energy embarked on a critical process to focus available resources on critical services, programs and projects. As part of supporting crucial business operations, information technology enhancements and changes were made to integrate new business rules into existing business applications (arising from the 2010 Government Competitiveness Review).

The *IT Re-Investment Initiative*, a significant 5-year project was completed. This resulted in five mission critical mainframe business applications being successfully redeveloped and reengineered to operate on a current technology platform. We also participated in the *GeoDiscover Alberta Project,* an innovative partnership between the Ministries of Energy, Environment and Sustainable Resource Development which together developed and delivered map services and geographic information about our province to government and the public.

A joint *Oil Sands Internship Program* was developed and launched with Alberta Environment to focus development of staff for deployment in this important area. In addition, the Energy/ Environment joint *Mentorship Program* continued to build important relationships for collaboration and integration of shared objectives. *The Energy 101 Program* was launched in the fall of 2010 as a partnership with the University of Alberta to provide a comprehensive foundation of knowledge about the energy sector in Alberta for our staff. Oil Sands Interns are the first *Energy 101* participants.

Performance Measure:

11.a Industry satisfaction

Target:

Industry satisfaction 80 per cent or higher.

Results:

			Year Ending December 31
	Actual 2005	**Actual 2007**	**Last Actual 2009**
Industry satisfaction			
• with Department services	84%	83%	82%
• with Department electronic information management	90%	90%	90%

Source: Banister Research and Consulting

Discussion of Results

Results for this performance measure are derived from a biennial survey, with the next survey being conducted in fall 2011. The most recent survey, for the calendar year 2009, was conducted in October and November 2009. The survey results for 2009 were similar to the results achieved for the years 2005 and 2007, and reflected high levels of stakeholder satisfaction with Department services. A satisfaction rate of 82 per cent was achieved in 2009, down one per cent from the 2007 survey results. The helpfulness and professionalism of Department staff was rated at 85 per cent, contributing to an overall high result. Results are considered accurate +/- 4.3 per cent 19 times out of 20.

The Department applied the Government of Alberta’s framework for service excellence, focusing on courteous, competent and timely service to clients. Industry satisfaction was surveyed to ensure that Department services kept pace with changing requirements in the energy sector and identified opportunities for improvements. Industry satisfaction is an indicator of staff competence, knowledge, satisfaction and service.

In an increasingly global business environment where partnerships and information sharing are keys to success, effective use of information technology to deliver business products/services and manage information is essential. Industry satisfaction with electronic information management is surveyed to assess the Department’s commitment to system availability and security, timeliness and ease of use. Results for industry satisfaction with electronic information management in 2009, the last year the survey was conducted, are considered accurate +/- 3.4 per cent 19 times out of 20. The 90 per cent satisfaction rate was identical to what was achieved in 2007.

High levels of satisfaction with Department services and electronic information management, demonstrated by the last three biennial surveys, indicate that the Department has been consistently meeting stakeholder expectations. The results for 2009 were virtually unchanged from 2007 and 2005.

Performance Measure:

11.b Work Environment

Target:

Achievement of satisfaction targets for Employee Engagement and Quality Work Environment.

Results:

			Year Ending December 31
	Actual 2008	**Actual 2009**	**Last Actual 2010**
Work Environment:			
Department:			
• Employee Engagement	76%	75%	68%
• Quality Work Environment	77%	75%	71%
ERCB:			
• Employee Engagement	81%	80%	73%
• Quality Work Environment	80%	79%	75%
AUC:			
• Employee Engagement	88%	81%	75%
• Quality Work Environment	86%	81%	78%

Source: Resinnova

Discussion of Results

Having the right employees in the right jobs and having these employees engaged are key to the success of the organization as a whole. To measure this progress, the Quality Work Environment and Employee Engagement indices serve as indicators of staff morale, knowledge and satisfaction, which are gauged through a formal survey of all employees in the Department of Energy, ERCB and AUC.

Each organization has an ongoing and direct influence in creating and maintaining an environment where employees feel engaged and enjoy a positive and values-based work environment. The organizations monitor the work environment to identify opportunities for improvement, and to address changing requirements for its employees. The most recent survey for the Department, ERCB and AUC for calendar year 2010 was conducted in the Fall (October and November) of 2010.

Employees were interviewed and asked a series of questions. Of these questions, six are used for Employee Engagement and 11 are used for Quality Work Environment.

Department

While survey results fell short of the target of 80 per cent, they reflect a fairly positive level of satisfaction amongst the 527 surveyed employees, with Quality Work Environment and level of Employee Engagement.

ERCB

Though the survey results were slightly lower in 2010 compared to 2009 and fell short of the targets, 75% for Employee Engagement and 78% for Quality Work Environment, the results reflect that the ERCB employees continue to feel satisfied about their level of engagement and positive work environment. A total of 843 (or 91%) employees from the ERCB were interviewed.

AUC

The targets for both the Employee Engagement and Quality Work Environment indexes were 80 per cent or higher. The survey results for both indexes were lower in 2010 compared to 2009 and did not meet the established targets. Although the results did not meet or exceed the targets, the consistent high results are a reflection of the positive level of satisfaction amongst staff. The AUC recognizes that the delivery of its core business depends on the expertise and commitment of its people. A total of 90 per cent of all AUC employees participated in the 2010 Employee Survey.

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 royalty and tax rate includes the following:

- Royalty
- Corporate income taxes (Federal & State/Provincial)
- Severance taxes
- Ad Valorem taxes

Comparator jurisdictions for Alberta include British Columbia, Saskatchewan, and the following USA states: Texas, Louisiana, Wyoming, Colorado, New Mexico, California, Pennsylvania, Oklahoma, and New York.

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

This measure should be treated as an “early warning” signal to indicate whether the royalty system requires amendment. If comparison of combined royalty and tax 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 Competiveness Study) that are future focused and account for the many factors that influence investment decisions

Performance Measures

2.a Revenues from Oil, Oil Sands, Gas and Land Sale Bonuses are accurately calculated
2.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, rather than invoiced. The volumes owed are imported from RAM into the Crude Oil Operation (COO) system. Reconciliation between the volumes calculated by RAM and the volumes actually delivered by industry is performed by the Department and any discrepancies are resolved. The Department collects the revenue for the Crown's volumes marketed either directly or by the Crown's agent(s) and calculates the net value of all royalty sales and remit proceeds to Treasury.

Oil Sands Royalty:

The database, Oil Sands Calculation and Registry system (OSCAR), calculates the monthly amount to be collected based on the monthly Good Faith Estimates (GFE) and the Monthly Royalty Calculations (MRC) spreadsheets. The OSCAR system then sends the revenue data to the Corporate Accounting Revenue System (CARS 2). There are no manual interfaces and the data is reconciled monthly between these two systems. Oil Sands does not invoice revenue clients but requires them to remit their revenue payment with their form reporting. Within two working days of processing the form reporting, account reconciliation is completed to ensure funds owing have been received from the revenue client. Any revenue account discrepancies found are investigated and reconciled within the next monthly reporting cycle.

The monthly Conventional Oil Sands Royalty Calculation (PSR) spreadsheets are received and manually processed in Excel. As noted previously, Oil Sands does not invoice revenue clients but requires them to remit their revenue payment with their form reporting. Reconciliation between the form reporting and funds received is completed within the monthly reporting cycle and any revenue account discrepancies found are investigated and resolved within the next monthly reporting cycle.

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 CARS 2 and a Statement of Account is generated on or before the 15th 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 CARS 2 system. Collection action occurs on accounts that are past due.

Land Sale Bonuses (and Oil Sands Tenure):

The majority of P&NG agreements are acquired through a public tender process. Each year the Department holds an average of 24 sales, referred to as "Public Offerings". The word "sale" is used by tradition, although it is a misnomer, since the Crown always retains title to its minerals. The rights are leased, not sold. The process is an auction, in which companies or individuals submit bids on a parcel of mineral rights. The highest bidder for each parcel is awarded a P&NG agreement.

Any company or individual who wishes to acquire a P&NG agreement may submit a posting request electronically, to the Department, using the web-based Electronic Transfer System (ETS). The Department examines the requested rights to ensure that they are undisposed, and refers the request to the multi-agency Crown Mineral Disposition Review Committee to review surface access restrictions relating to the requested lands. 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, will be attached to the rights when they are posted in the Public Offering Notice and will be recorded in the Notice to Lessee as an attachment to the agreement document upon issuance. The Public Offering Notice is published on the Department's website eight weeks before the date of each sale.

A company or individual can create and submit a bid electronically through ETS. At 12:00 noon the sale is closed and ETS will not allow a user to submit or withdraw a bid after that time. The total bid request for each parcel includes a $625 agreement issuance fee, the rental for the first year of the agreement at $3.50 per hectare, and a bonus amount. There is a standard minimum bonus bid of $2.50 per hectare for leases and $1.25 per hectare for licences. The form of payment accepted for winning bids is by electronic funds transfer (EFT). The bidder must be set up for EFT before creating and submitting a bid.

The results of each sale are published on the Department's website, normally at 3:30 pm on the day of the sale. The results include the name of each successful lessee and the bonus amount paid for each parcel.

Performance Measure

3.a Carbon Capture and Storage

Methodology

Injected volumes of carbon dioxide will be reported to Alberta Energy to satisfy the terms of the grant agreements. Currently the terms of these grant agreements are being negotiated and therefore the specifics of this methodology are unknown.

Carbon dioxide injection data is also available through Alberta Environment. Together with the Energy Resources and Conservation Board (ERCB), these sources will be used to confirm the quantities being reported.

Performance Measure

3.b Upstream Oil and Gas Industry Investment

Methodology

This measure relies on capital expenditure data in Statistics Canada's PPI in Canada publications. PPI is a comprehensive national publication, which reports investment for all sectors and industries in Canada, for which data is available. Capital expenditures, or investment, include the cost of procuring, constructing and installing new durable plant, machinery and equipment, and capitalized costs such as feasibility studies, architectural, installation and engineering fees, among other things.

Performance Measure

4.a Ethane Demand in Alberta

Methodology

Information provided by the ERCB is used to determine the demand of ethane for the province of Alberta.

The Incremental Ethane Extraction Program (IEEP) has recently been extended to December 31, 2021.

- Projects are allowed to apply to be tagged as incremental ethane sources until December 31, 2016.
- Projects that are deemed to be incremental sources of ethane are eligible to receive fractionation credits for five years (up until the end date for the program of December 31, 2021).

The goal of IEEP is to increase the production of ethane in the province above the forecasted Ethane Consumption Baseline (ECB). The ECB was developed by a consultant group (Purvin and Gertz) based on their best estimates of both production of and demand for ethane. IEEP hopes to encourage private investment to increase the production of ethane by 60,000-85,000 barrels per day above the forecasted ECB by the end of program. The increase is expected to maintain the production of ethane in the province at a relatively stable level (i.e. the expected drop in production without extra investment will approximately equal this increase in production).

Performance Measure

4.b Ethanol Production in Alberta

Methodology

Production capacity results are based on information published by Permolex International, L.P.

Actual production is reported to the Department of Energy on monthly invoices filed by companies under the Bioenergy Producer Credit Program (BPCP) in order to validate the amount of credit claimed for bioenergy production. Production data for ethanol facilities that apply and qualify under the BPCP will continue to be collected until the program ends in March 2016. This data includes production for both Alberta and export markets.

Performance Measure

4.c Biodiesel Production in Alberta

Methodology

In order to monitor the growth in biodiesel production capacity in Alberta, the Department developed a new performance measure, which first appeared in the 2008-11 Business Plan. At the time, there was no biodiesel production in Alberta, so targets were based on a conservative projection based on projects which received bioenergy grant funding.

Actual production is reported to the Department of Energy on monthly invoices filed by companies under the Bioenergy Producer Credit Program (BPCP) in order to validate the amount of credit claimed under the program for bioenergy production. Production data for Western Biodiesel, and any new biodiesel facilities which qualify under the BPCP, will continue to be collected until the program ends in March 2016. This data includes production for both Alberta and export markets.

Performance Measure

5.a Albertans' Assessment of their Energy Knowledge

Methodology

This performance measure was introduced in the 2010-13 Business Plan. The survey question was incorporated within the April 2011 OmniAlberta Survey, conducted by Leger Marketing. Based on the 900 sample size of Albertans aged 18 years or older surveyed by telephone, results are statistically accurate to within +3.3 percentage points, 19 times out of 20.

The intent of this performance measure is to survey Albertans every two years with the same question about their knowledge of the energy industry in Alberta, to determine changes since the 2009 benchmark was established.

Performance Measure
6.a Increased Fuel gas Efficiency Reporting

Methodology
A biennial data collection process is undertaken by the ERCB (or other reliable and credible source) in which the top fuel gas users are asked to voluntarily provide information regarding their efforts to better manage fuel gas consumption. The ERCB provides this, and other information associated to fuel gas use, in a report that is publicly released. The following fuel gas users accounted for 68 per cent of all fuel gas use in Alberta in 2008 and were the participants of the initial ERCB data collection process.

- EnCana
- Canadian Natural Resources
- ConocoPhillips
- Husky
- Shell
- Keyera
- Devon
- Talisman
- Penn West
- Petro Canada
- Apache
- SemCAMS
- BP
- AltaGas
- Taqa North

Performance Measure
7.a Magnitude of Transmission Must Run (TMR) Congestion (GWh); Magnitude of Constrained Down Generation (GWh); Transmission Losses (%)

Methodology
The transmission data will be provided by the Alberta Electric System Operator (AESO). The AESO operates under authority of legislation and is responsible for the operation of the Alberta Interconnected Electric System. The data provided is integral to the ongoing operation of the AESO. The AESO has provided written assurance that they will provide the necessary data and have sufficient business practice controls in place to ensure the accuracy of the data.

Performance Measure
7.b Number of Microgeneration Sites

Methodology
The micro-generation data is provided by the Alberta Electric System Operator (AESO). The AESO operates under authority of legislation and is responsible for the operation of the Alberta Interconnected Electric System. Ongoing data collection and maintenance is one of the integral functions of the AESO. The AESO has provided written assurance that they will provide the necessary data and have sufficient business practice controls in place to ensure the accuracy of the data.

Performance Measure

8.a Data Accessibility

Methodology

This measure was developed in order to foster a more open environment for innovation. The concept for this measure came from the 2008 report to the US Secretary of Commerce by the Advisory Committee on Measuring Innovation in the 21st Century Economy entitled *Innovation Measurement- Tracking the State of Innovation in the American Economy*. The report suggests that public access to data encourages more non-governmental research. It is the goal of the Ministry to improve technology and processing in the energy sector and by providing greater access to research and creating and maintaining a research repository will promote innovation to lead to these developments.

Department facilitated research can be defined as research for which:

a) The Department is the contract manager.

b) The Department contributes financially, but is not the contract manager.

The research documents will be collected as follows:

- For research that has been contracted by the Department and for which we are the contract manager, the document will be collected through the approval process. Contracts with associated research documents as a deliverable will be identified and upon the contract closing date, the contract manager will be required to provide a copy for placement in the repository.
- The repository manager will be responsible for collecting documents from the contract manager.

The target will be calculated through tracking research in the Department, as described above. The number of research documents placed in the repository will be calculated as a percentage of the total research reports created.

Performance Measure

9.a 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, have been removed 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, 2010 through to March 31, 2011) as recorded by the Alberta Electric System Operator.

Methodology for calculating the margin was adjusted for the 2009-10 Annual Report. Previously, the margin was reported as the difference between total installed generating capacity (net of wind capacity) and peak demand. As a further refinement to the method, a portion of the hydro capacity has also been excluded from the calculation of the firm generating capacity. From an operational point of view, some portion of the hydro capacity may not be available at all times, especially when the peak demand occurs in the winter, due to the limited water storage capacity in the reservoirs. This aspect of the hydro units may put limitations on the amount of generation that can be dispatched from these units on a consistent basis. This adjustment helps further refine the calculation of the margin and makes it more representative of the situations where the full hydro capacity may not be available.

Performance Measure

10.a Regulatory Noncompliance

Methodology

This indicator measures industry's compliance with regulatory requirements.

ERCB 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. This information is then reported in the annual *ST57: Field Surveillance and Operations Provincial Surveillance and Compliance Summary Report*, which reports on a calendar-year basis. 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.

A High Risk noncompliance is when a contravention of regulation(s) /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.

Performance Measure

10.b 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.

Performance Measure

11.a Industry satisfaction

Methodology

In October and November 2009, Banister Research and Consulting Inc. conducted telephone interviews with client groups that do business with the Department of Energy.

For industry satisfaction with Department services the focus of courteous, competent and timely service to clients was used to develop questions given to 350 randomly selected industry clients. Results are a mean average of client responses to a single question on overall satisfaction with nine business units.

In order to gauge satisfaction with electronic information management, 656 randomly selected industry companies were asked questions about availability, security, timeliness and ease of use of Department electronic data processing systems. Results are a mean average of client responses to these questions.

Performance Measure

11.b Work Environment

Methodology

Surveying for the measure is conducted each year. The most recent survey, for calendar year 2010, was conducted in October and November of 2010. An independent third party, Resinnova, is engaged to conduct the annual employee survey. Individual responses to the survey questions remain anonymous and only aggregate results are delivered to each government organization.

A total of 843 (or 91 per cent) employees from the ERCB were surveyed, as well as 527 (or 84 per cent) employees from the Department of Energy, and 117 (90 per cent) from the AUC. Initial surveys were conducted through an on-line questionnaire. If employees did not respond between October 26 and November 19, a telephone interview was conducted. Out of these questions, the results of six were used for Employee Engagement and 11 were used for Quality Work Environment. The same questions for Employee Engagement and Quality Work Environment are being used each year to ensure validity and consistency. Both management and non-management employees are surveyed.

MINISTRY OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2011

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, 2011, 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, 2011, 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, CA

Auditor General

June 7, 2011
Edmonton, Alberta

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF OPERATIONS

Year ended March 31, 2011

(in thousands)

	2011		2010
	Budget (Schedule 3)	Actual	Actual
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 7,315,000	$ 8,427,931	$ 6,767,941
Freehold Mineral Rights Tax	167,000	127,465	124,466
Industry Levies and Licences	150,233	146,316	142,226
Other Revenue	12,659	10,317	45,833
	7,644,892	8,712,029	7,080,466
Expenses - Directly Incurred (Note 2 and Schedules 2 and 3)			
Ministry Support Services	2,195	1,841	2,010
Resource Development and Management	243,147	138,604	176,214
Energy and Utilities Regulation	211,185	212,008	209,737
	456,527	352,453	387,961
Net Operating Results	$ 7,188,365	$ 8,359,576	$ 6,692,505

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at March 31, 2011

	(in thousands) 2011	2010
Assets		
Cash and Cash Equivalents (Notes 3 and 7)	$ 460,075	$ 532,113
Accounts Receivable (Note 4)	967,739	1,292,459
Inventory Held for Resale	17,528	16,595
Prepaid Expenses	10,898	6,474
Accrued Pension Asset (Note 8)	7,524	8,298
Tangible Capital Assets (Note 5)	109,534	87,860
	$ 1,573,298	$ 1,943,799
Liabilities		
Accounts Payable and Accrued Liabilities	$ 975,637	$ 643,719
Gas Royalty Deposits (Note 6)	473,420	1,040,553
Unearned Revenue	75,352	71,414
Security Deposits (Note 7)	43,578	38,557
Tenant Incentives	25,215	428
	1,593,202	1,794,671
Net Assets (Liabilities):		
Net Assets (Liabilities) at Beginning of Year	149,128	(173,857)
Net Operating Results	8,359,576	6,692,505
Net Financing Provided from (for) General Revenues	(8,528,608)	(6,369,520)
Net Assets (Liabilities) at End of Year	(19,904)	149,128
	$ 1,573,298	$ 1,943,799

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended March 31, 2011

	(in thousands)	
	2011	**2010**
Operating Transactions		
Net Operating Results	$ 8,359,576	$ 6,692,505
Non-cash items included in Net Operating Results		
Amortization	24,042	21,520
Loss on Disposal of Tangible Capital Assets	-	500
Valuation Adjustments	257	784
	8,383,875	6,715,309
Decrease (Increase) in Accounts Receivable	324,720	(709,468)
Decrease (Increase) in Inventory	(933)	(16,595)
Decrease (Increase) in Prepaid Expenses and Accrued Pension Asset	(3,650)	(3,469)
Increase (Decrease) in Accounts Payable and Accrued Liabilities	331,874	411,268
Increase (Decrease) in Unearned Revenue	3,938	(238)
Decrease (Increase) in Tenant Incentives	(852)	(642)
Reduced Rent Benefits	4,000	-
Cash Provided by (Applied to) Operating Transactions	9,042,972	6,396,165
Capital Transactions		
Acquisition of Tangible Capital Assets	(24,290)	(26,491)
Proceeds on Disposal/Sale of Tangible Capital Assets	-	38
Cash Provided by (Applied to) Capital Transactions	(24,290)	(26,453)
Financing Transactions		
Net Financing Provided from (for) General Revenues	(8,528,608)	(6,369,520)
Increase (Decrease) in Gas Royalty Deposits	(567,133)	339
Increase in Security Deposits	5,021	2,616
Cash Provided by (Applied to) Financing Transactions	(9,090,720)	(6,366,565)
Increase (Decrease) in Cash and cash equivalents	(72,038)	3,147
Cash and cash equivalents at Beginning of Year	532,113	528,966
Cash and cash equivalents at End of Year	$ 460,075	$ 532,113

Non-cash transactions:		
Additions to property and equipment received as a lease incentive	$ 21,425	$ -

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

MINISTRY OF ENERGY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(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*
Energy Resources Conservation Board (The ERCB)	*Energy Resources Conservation Act*
Alberta Utilities Commission (The AUC)	*Alberta Utilities Commission Act*
Alberta Petroleum Marketing Commission (The Commission)	*Petroleum Marketing Act and the Natural Gas Marketing Act*

Note 2 Summary of Significant Accounting Policies and Reporting Practices

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

Basis of Financial Reporting

Basis of Consolidation

The accounts of the Department, the ERCB, the AUC, and the Commission are consolidated. Revenue and expense transactions, capital and financing transactions, and related asset and liability accounts between entities within the Ministry have been eliminated.

The reporting period of the Commission is December 31. Transactions that have occurred during the period January 1 to March 31 and that significantly affect the consolidation have been recorded.

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.

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

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

Note 2 Summary of Significant Accounting Policies and Reporting Practices (continued)

Basis of Financial Reporting (continued)

Revenues (continued)

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

Directly Incurred

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 comprise the cost of employer contributions for current service of employees during the year.

- current service costs for the defined benefit pension plans. The ERCB and the AUC have their own defined benefit pension plans. The ERCB'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 length of service to the time of retirement. Net accumulated actuarial gain or loss is deferred and amortized over the average remaining service period of the active employees, which is 8 years. For the purpose of calculating the expected return, plan assets are valued at fair value. Past service costs arising from plan amendments are deferred and amortized on a straight line basis over the average remaining service period of active employees at the date of 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.

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 Ministry operations 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 (continued)

Basis of Financial Reporting (continued)

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 to parties external to the government reporting entity, the fair 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, 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 (Liabilities)

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

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, 2011, securities held by the Fund have a time-weighted rate of return of 1.1% per annum (2010: 1.0% per annum). Deposits received by the Ministry as security against leases are included in cash.

Note 4 Accounts Receivable

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

(in thousands)

Note 5 Tangible Capital Assets

	Land	Equipment	Computer hardware and software	2011 Total	2010 Total
Estimated Useful Life	Indefinite	3 to 10 years	3 to 20 years		
Historical Cost					
Beginning of Year	$ 282	$ 49,119	$ 192,287	$ 241,688	$ 218,772
Additions	-	24,082	21,634	45,716	26,491
Disposals, Including Write-Downs	-	(7,370)	(14,795)	(22,165)	(3,575)
	$ 282	$ 65,831	$ 199,126	$ 265,239	$ 241,688
Accumulated Amortization					
Beginning of Year	$ -	$ 32,033	$ 121,795	$ 153,828	$ 135,345
Amortization Expense	-	5,314	18,184	23,498	21,520
Effect of Disposals	-	(7,314)	(14,307)	(21,621)	(3,037)
	$ -	$ 30,033	$ 125,672	$ 155,705	$ 153,828
Net Book Value, March 31, 2011	$ 282	$ 35,798	$ 73,454	$ 109,534	
Net Book Value, March 31, 2010	$ 282	$ 17,086	$ 70,492		$ 87,860

Equipment includes leasehold improvements, office equipment and furniture, and other equipment.

Historical cost includes work-in-progress at March 31, 2011 totaling $6,167 (2010 - $13,871) comprised of 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.

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, 2011, the Ministry held $43,578 (2010: $38,557) in cash and an additional $84,315 (2010: $77,717) in letters of credit. 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 $17,115 for the year ended March 31, 2011 (2010 - $14,051).

At December 31, 2010, the Management Employees Pension Plan reported a deficiency of $397,087 (2009 – deficiency $483,199) and the Public Service Pension Plan reported a deficiency of $2,067,151 (2009 deficiency – $1,729,196). At December 31, 2010, the Supplementary Retirement Plan for Public Service Managers had a deficiency of $39,559 (2009 – deficiency $39,516).

(in thousands)

Note 8 Employee Future Benefits (continued)

The Ministry also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2011, the Bargaining Unit Plan reported an actuarial deficiency of $4,141 (2010 – deficiency $8,335) and the Management, Opted Out and Excluded Plan an actuarial surplus of $7,020 (2010 – surplus $7,431). The expense for these two plans is limited to the employer's annual contributions for the year.

In addition, the ERCB 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, 2011. The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2008. The effective date of the next required funding valuation for SEPP is December 31, 2011. Significant actuarial and economic assumptions used to value accrued benefit obligations and pension costs are as follows:

a) ERCB

	2011	2010
Accrued benefits obligations		
Discount rate	5.8%	6.2%
Rate of compensation increase (weighted average)	3.5%	3.5%
Benefit costs for the year		
Discount rate	6.2%	8.6%
Expected long-term rate of return on plan assets	6.5%	6.5%
Rate of compensation increase	3.5%	3.5%

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

	2011	2010
Plan assets at fair value	$ 31,561	$ 28,497
Accrued benefit obligation	32,902	28,544
Plan (deficit) surplus	(1,341)	(47)
Unamortized net actuarial loss	7,962	7,474
Accrued pension asset	$ 6,621	$ 7,427

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

	2011	2010
Equity securities	46.7 %	46.5 %
Debt securities	41.9 %	41.7 %
Other	11.4 %	11.8 %
	100.0%	100.0%

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

	2011	2010
ERCB contribution	$ 1,626	$ 812
Employees' contribution	395	386
Benefit paid	1,249	851
Pension benefit costs	2,432	808

(in thousands)

Note 8 Employee Future Benefits (continued)

b) AUC

	2011	2010
Accrued benefits obligations		
Discount rate	5.8%	6.2%
Rate of compensation increase (weighted average)	3.5%	3.5%
Benefit costs for the year		
Discount rate	6.2%	8.6%
Expected long-term rate of return on plan assets	6.1%	6.2%
Rate of compensation increase	3.5%	3.5%

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

	2011	2010
Fair value of plan assets	$ 4,317	$ 3,450
Accrued benefit obligation	4,566	3,607
Plan (deficit) surplus	(249)	(157)
Unamortized net actuarial (gain) loss	1,152	1,028
Accrued pension asset	$ 903	$ 871

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

	2011	2010
AUC contribution	$ 594	$ 200
Employees' contribution	102	100
Benefit paid	80	231
Pension benefit costs	562	178

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

	2011	2010
Equity securities	50.8 %	44.5 %
Debt securities	32.8 %	39.5 %
Other	16.4 %	16.0 %
	100.0%	100.0%

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:

	2011	2010
Oil and Gas Conservation Trust	$ 3,921	$ 3,806

(in thousands)

Note 10 Commitments

Commitments to outside organizations in respect of contracts entered into before March 31, 2011 amount to $205,459 (2010 - $247,645). These commitments will become expenses of the Ministry when terms of the contracts are met. Payments in respect of these contracts and agreements are subject to the voting of supply by the Legislature.

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

	Grant Agreements	Service Contracts	Long-term Leases	Total
2012	$ 125	$ 19,254	$ 9,641	$ 29,020
2013	-	3,056	9,484	12,540
2014	-	2,486	9,606	12,092
2015	-	2,486	9,462	11,948
2016	-	2,493	9,708	12,201
Thereafter	-	-	127,658	127,658
	$ 125	$ 29,775	$ 175,559	$ 205,459

Alberta Petroleum Marketing Commission

The Alberta Petroleum Marketing Commission (Commission) has allocated a portion of its anticipated pipeline requirements to transportation agreements expiring in March 2012. These agreements obligate the Commission to pay tariff charges for contracted volumes in accordance with contracted rates. The aggregate estimated commitment at December 31, 2010 is $9,813 (2009 - $17,986). This commitment will be paid from future oil royalty revenue. Costs for these pipeline services are expected to be within the range of normal transportation costs.

	Total
2012	$ 7,850
2013	1,963
	$ 9,813

On February 16, 2011, the Commission announced it had entered into agreements with North West Redwater Partnership (Partnership) to process and market Crown royalty bitumen collected under the Bitumen Royalty in Kind initiative. Development of the bitumen refinery to be constructed by the Partnership is dependent on completion of detailed engineering, final project sanction, and acquisition of necessary financing.

Note 11 Contingent and Other 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 set 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. In one instance, the Ministry may have to revoke 12 petroleum and natural gas dispositions for which the government accepted bonuses, rental payments and royalties. 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.

Note 11 Contingent and Other Liabilities (continued)

(b) Legal Claims

At March 31, 2011, the Ministry is a defendant in six legal claims (2010 – six legal claims). Four of these claims have specified amounts totaling $1,373,174 and the remaining two claims have no specified amount (2010 – four with specified amounts totaling $1,373,265 and the remaining two claims with no specified amount). The Ministry has been jointly named with other entities in four claims (2010 – all claims specified amounts totaling $1,373,265). One claim totaling $572,500 (2010 – $572,500) is covered by the Alberta Risk Management Fund.

The resulting loss, if any, from these claims cannot be determined.

(c) Bitumen Royalties

On January 1, 2009, the Province implemented the New Royalty Framework. As part of the New Royalty Framework, the Bitumen Valuation Methodology (Ministerial) Regulation (the "BVM Regulation") was enacted. The BVM Regulation establishes a method to determine a deemed price for bitumen for producers who dispose of bitumen mostly through non-arm's length transactions. This price so determined factors into the calculation of royalties due to the Province from oil sands projects.

The Province has "Royalty Amending Agreements" with two oil sands royalty projects, governing royalties through 2015. In each case the Royalty Amending Agreement (RAA) undertakes that the bitumen valuation methodology ("BVM") applicable to the project will include "reasonable adjustments" to reflect quality differences between the project's bitumen and the bitumen reflected in the deemed price used in the BVM Regulation and also to reflect transportation costs to the reference price location.

Non-renewable resource revenue reported in 2011 on the consolidated statement of operations includes an estimate of the royalties that the Ministry expects to recover from the Suncor and Syncrude projects.

During 2009, Suncor and Syncrude filed non-compliance notices with the Province, alleging that the BVM Regulation does not address the reasonable quality and transportation adjustments required by their respective RAAs.

The Province amended the Oil Sands Royalty Regulation in 2009 to include a methodology to determine royalty amounts due to the Province on pre-2009 inventory and pre-2009 transitional inventory. This royalty was due April 30, 2010. Suncor and Syncrude have indicated that no amounts are owing for this inventory because of their RAAs. The Ministry has forwarded letters advising Suncor and Syncrude to pay their royalty amounts according with BVM Regulation.

The Royalty Amending Agreements include a dispute resolution process that, if unsuccessful, will culminate in the one instance in arbitration and in the other instance in Court proceedings. Bitumen royalties reported may be adjusted following resolution of these issues, potentially significantly.

Note 12 Measurement Uncertainty

Measurement uncertainty exists when there is a significant variance between the amount recognized in the consolidated financial statements and another reasonably possible amount. Natural gas and by-products revenue recorded as $1,415,871 and bitumen royalty recorded as $3,723,412 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 synthetic crude oil and bitumen royalties are 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.

Drilling royalty credits recorded under the Energy Industry Drilling Stimulus Program include an estimate of $114,113 for credits expected to be claimed in the future for estimated natural gas royalties for February and March 2011 and for oil royalties for March 2011 and $224,750 for credits that have yet to be allocated. The actual amounts claimed and paid could be materially different than the amount estimated. The program expired on March 31, 2011.

Note 13 Related Party Transactions

The Ministry paid $6,665 (2010 - $5,466) to various other Government of Alberta departments, agencies or funds for supplies and/or services during the fiscal year and received $408 (2010 - $293) as revenue. Included in these services was a payment of $48 (2010 - $48) for the lease of a research facility from Alberta Infrastructure. The remaining term of this lease is 75 years and the future annual payments are $48.

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 14 Royalty Reduction Programs

The Ministry provides the Energy Industry Drilling Stimulus Program along with seven other 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, 2011, the royalties received under these programs were reduced by $2,440,635 (2010 - $1,465,144).

Note 15 Bitumen Conservation

In 2004-05 the Alberta Energy and Utilities (EUB) Board 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 $57,589 (2010 - $64,115).

Note 16 Energy Industry Drilling Stimulus Program

Starting April 1, 2009, the Department implemented a drilling stimulus program that impacted the royalties for the year ended March 31, 2011. The first feature was a maximum royalty rate of 5% for the first 50,000 barrels of oil or 500,000 Mcf of gas produced from a well drilled on or after April 1, 2009. The program expired on March 31, 2011.

The second feature was a drilling credit of $200 per metre for wells drilled between April 1, 2009 and March 31, 2011. A sliding scale of 10% to 50%, (based on the oil and gas production level of a company) of 2010/2011 natural gas and conventional oil royalties, caps the amount of the credit a company can receive. The program expired on March 31, 2011.

In the fiscal year ended March 31, 2011, natural gas and by-product royalties and conventional oil royalties were reduced by $384,819 (2010 - $197,226) and $486,793 (2010 - $135,625) respectively due to the New Well Royalty Rate feature, while $901,905 (2010 - $786,203) was reduced due to the drilling credit feature.

Note 17 Approval of Financial Statements

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

MINISTRY OF ENERGY **Schedule 1**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Revenues

Year ended March 31, 2011

	(in thousands)		
	2011		**2010**
	Budget	**Actual**	**Actual**
Non-Renewable Resource Revenue			
Bitumen Royalty (Note 11c)	$ 3,249,000	$ 3,723,412	$ 3,160,349
Crude Oil Royalty	2,137,000	2,236,290	1,848,269
Natural Gas and By-Products Royalty	1,861,000	1,415,871	1,525,397
Bonuses and Sales of Crown Leases	630,000	2,634,503	1,164,407
Rentals and Fees	135,000	160,864	157,707
Coal Royalty	35,000	30,508	30,866
Energy Industry Drilling Stimulus Program (Note 16)	(732,000)	(1,773,517)	(1,119,054)
	7,315,000	8,427,931	6,767,941
Freehold Mineral Rights Tax	167,000	127,465	124,466
Industry Levies and Licenses	150,233	146,316	142,226
Other Revenue			
Other	9,859	9,235	45,074
Interest	2,800	1,082	759
	12,659	10,317	45,833
Total Revenue	$ 7,644,892	$ 8,712,029	$ 7,080,466

MINISTRY OF ENERGY **Schedule 2**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Expenses - Directly Incurred Detailed by Object

Year ended March 31, 2011

	(in thousands)		
	2011		**2010**
	Budget	**Actual**	**Actual**
Voted			
Salaries, Wages and Employee Benefits	$ 200,062	$ 193,289	$ 190,579
Supplies and Services	80,048	92,465	93,314
Grants	142,809	29,725	68,709
Amortization of Tangible Capital Assets	21,088	24,042	22,020
Well Abandonment	13,000	13,094	13,000
Valuation Adjustments	-	257	784
Financial Transactions and Other	120	116	120
Total Voted Expenses before Recoveries	457,127	352,988	388,526
Less Recovery from Support Service Arrangements with Related Parties	(600)	(535)	(565)
Total Voted Expenses	$ 456,527	$ 352,453	$ 387,961

MINISTRY OF ENERGY **Schedule 3**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Allocated Costs

Year ended March 31, 2011

(in thousands)

	2011									2010
		Expenses Incurred by Others						Valuation Adjustments		
Program	Expenses [1]	Accommodation Costs	Transportation Costs	Service Alberta	GOA Learning Centre	Legal Services	Audit Services	Vacation Pay	Total Expenses	Total Expenses
Ministry Support Services	$ 1,834	$ 160	$ -	$ -	$ -	$ 55	$ -	$ 7	$ 2,056	$ 2,467
Resource Development and Management	138,354	5,639	607	6,997	43	4,070	36	250	155,996	190,211
Energy and Utilities Regulation	212,008	-	-	-	-	-	-	-	212,008	209,737
	$ 352,196	$ 5,799	$ 607	$ 6,997	$ 43	$ 4,125	$ 36	$ 257	$ 370,060	$ 402,415

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

DEPARTMENT OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2011

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, 2011, 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, 2011, 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, CA

Auditor General

June 7, 2011
Edmonton, Alberta

DEPARTMENT OF ENERGY

STATEMENT OF OPERATIONS

Year ended March 31, 2011

	(in thousands)		
	2011		**2010**
	Budget (Schedule 3)	**Actual**	**Actual**
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 7,315,000	$ 8,427,931	$ 6,767,941
Freehold Mineral Rights Tax	167,000	127,465	124,466
Other Revenue	500	1,549	38,260
	7,482,500	8,556,945	6,930,667
Expenses - Directly Incurred (Note 2b and Schedule 6)			
Voted (Schedules 2 and 3)			
Ministry Support Services	2,195	1,841	2,010
Resource Development and Management	143,112	137,334	171,401
Energy and Utilities Regulation	57,993	56,493	67,193
	203,300	195,668	240,604
Statutory (Schedules 2 and 3)			
Valuation Adjustments			
Provision for Doubtful Accounts	35	-	2
Provision for Vacation Pay	-	257	782
Payments made under the *Mines and Minerals Act*	-	-	3,491
Carbon Capture and Storage	100,000	1,013	538
	100,035	1,270	4,813
	303,335	196,938	245,417
Net Operating Results	$ 7,179,165	$ 8,360,007	$ 6,685,250

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

DEPARTMENT OF ENERGY

STATEMENT OF FINANCIAL POSITION

As at March 31, 2011

	(in thousands) 2011	2010
Assets		
Cash	$ 356,950	$ 436,685
Accounts Receivable (Note 3)	964,750	1,301,283
Prepaid Expenses	1,937	1,904
Tangible Capital Assets (Note 4)	38,068	33,970
	$ 1,361,705	$ 1,773,842
Liabilities		
Accounts Payable and Accrued Liabilities (Note 5)	$ 912,995	$ 593,317
Gas Royalty Deposits (Note 6)	473,420	1,040,553
Unearned Revenue	73,735	69,816
	1,460,150	1,703,686
Net Assets (Liabilities):		
Net (Liabilities) Assets at Beginning of Year	70,156	(245,574)
Net Operating Results	8,360,007	6,685,250
Net Financing Provided for General Revenues	(8,528,608)	(6,369,520)
Net Assets (Liabilities) at End of Year	(98,445)	70,156
	$ 1,361,705	$ 1,773,842

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

DEPARTMENT OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2011

	(in thousands) 2011	2010
Operating Transactions		
Net Operating Results	$ 8,360,007	$ 6,685,250
Non-cash items included in Net Operating Results		
Amortization	6,228	5,491
Valuation Adjustments	257	784
	8,366,492	6,691,525
(Increase) Decrease in Accounts Receivable	336,533	(730,762)
(Increase) Decrease in Prepaid Expenses	(33)	(1,695)
Increase (Decrease) in Accounts Payable and Accrued Liabilities	319,421	417,825
Increase (Decrease) in Unearned Revenue	3,919	(313)
Cash Provided by Operating Transactions	9,026,332	6,376,580
Capital Transactions		
Acquisition of Tangible Capital Assets	(10,326)	(9,521)
Cash Applied to Capital Transactions	(10,326)	(9,521)
Financing Transactions		
Net Financing Provided for General Revenues	(8,528,608)	(6,369,520)
Increase in Gas Royalty Deposits	(567,133)	339
Cash Applied to Financing Transactions	(9,095,741)	(6,369,181)
Decrease in Cash	(79,735)	(2,122)
Cash at Beginning of Year	436,685	438,807
Cash at End of Year	$ 356,950	$ 436,685

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

DEPARTMENT OF ENERGY
NOTES TO THE FINANCIAL STATEMENTS
(in thousands)

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, the Energy Resources Conservation Board and the Alberta Utilities Commission. 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 Minister of Finance and Enterprise. 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 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 (continued)

(b) Basis of Financial Reporting (continued)

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.
- 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.

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.

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.

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

Note 2 Summary of Significant Accounting Policies and Reporting Practices (continued)

(b) Basis of Financial Reporting (continued)

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, 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 significant variance between the amount recognized in the financial statements and another reasonably possible amount. Natural gas and by-products revenue recorded as $1,415,871 and bitumen royalty recorded as $3,723,412 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.

Drilling royalty credits recorded under the Energy Industry Drilling Stimulus Program include an estimate of $114,113 for credits expected to be claimed in the future for estimated natural gas royalties for February and March 2011 and for oil royalties for March 2011 and $224,750 for credits that have yet to be allocated. The actual amounts claimed and paid could be materially different than the amount estimated. The program expired on March 31, 2011.

Note 3 Accounts Receivable

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

(in thousands)

Note 4 Tangible Capital Assets

	Equipment	Computer hardware and software	2011 Total	2010 Total
Estimated Useful Life	3 to 10 years	10 years		
Historical Cost				
Beginning of Year	$ 18,672	$ 89,882	$ 108,554	$ 99,596
Additions	1,522	8,804	10,326	9,521
Disposals	(4,064)	(12,829)	(16,893)	(563)
	$ 16,130	$ 85,857	$ 101,987	$ 108,554
Accumulated Amortization				
Beginning of Year	$ 14,268	$ 60,316	$ 74,584	$ 69,656
Amortization Expense	1,270	4,958	6,228	5,255
Disposals	(4,064)	(12,829)	(16,893)	(327)
	$ 11,474	$ 52,445	$ 63,919	$ 74,584
Net Book Value at March 31, 2011	$ 4,656	$ 33,412	$ 38,068	
Net Book Value at March 31, 2010	$ 4,404	$ 29,566		$ 33,970

Historical cost includes work-in-progress at March 31, 2011 totaling $0 (2010 - $10,829) for computer software. Computer software and equipment with a net book value of $0 (Cost: $16,892; Accumulated Amortization: $16,892) with no remaining economic life were disposed during the year. No gain or loss on disposal (2010 - $236 loss).

Note 5 Accounts Payable and Accrued Liabilities

	2011	2010
Trade	$ 44,403	$ 32,679
Energy Industry Drilling Stimulus Program and Overpayments of Royalties	866,092	556,835
Alberta Royalty Tax Credit	2,500	3,803
	$ 912,995	$ 593,317

Note 6 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 7 Contingencies and Other 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. In one instance, the Department may have to revoke 12 petroleum and natural gas dispositions for which the government accepted bonus, rental payments, and royalties. 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

At March 31, 2011, the Department is a defendant in six legal claims (2010 – six legal claims). Four of these claims have specified amounts totaling $1,373,174 and the remaining two claims have no specified amount (2010 – four with specified amounts totaling $1,373,265 and the remaining two claims with no specified amount). The Department has been jointly named with other entities in four claims (2010 – all claims specified amounts totaling $1,373,265). One claim totaling $572,500 (2010 – $572,500) is covered by the Alberta Risk Management Fund.

The resulting loss, if any, from these claims cannot be determined.

(c) Bitumen Royalties

On January 1, 2009, the Province implemented the New Royalty Framework. As part of the New Royalty Framework, the Bitumen Valuation Methodology (Ministerial) Regulation (the “BVM Regulation”) was enacted. The BVM Regulation establishes a method to determine a deemed price for bitumen for producers who dispose of bitumen mostly through non-arm’s length transactions. This price so determined factors into the calculation of royalties due to the Province from oil sands projects.

The Province has “Royalty Amending Agreements” with two oil sands royalty projects, governing royalties through 2015. In each case the Royalty Amending Agreement (RAA) undertakes that the bitumen valuation methodology (“BVM”) applicable to the project will include “reasonable adjustments” to reflect quality differences between the project’s bitumen and the bitumen reflected in the deemed price used in the BVM Regulation and also to reflect transportation costs to the reference price location.

Non-renewable resource revenue reported in 2011 on the statements of operations includes an estimate of the royalties that the Department expects to recover from Suncor and Syncrude.

During 2010, Suncor and Syncrude filed non-compliance notices with the Province, alleging that the BVM Regulation does not address the reasonable quality and transportation adjustments required by their respective RAAs.

The Province amended the Oil Sands Royalty Regulation in 2009 to include a methodology to determine royalty amounts due to the Province on pre-2009 inventory and pre-2009 transitional inventory. This royalty was due April 30, 2010. Suncor and Syncrude have indicated that no amounts are owing for this inventory because of their RAAs. The Department has forwarded letters advising Suncor and Syncrude to pay their royalty amounts according with BVM Regulation.

The Royalty Amending Agreements include a dispute resolution process that, if unsuccessful, will culminate in the one instance in arbitration and in the other instance in Court proceedings. Bitumen royalties reported may be adjusted following resolution of these issues, potentially significantly.

(in thousands)

Note 8 Energy Industry Drilling Stimulus Program

Starting April 1, 2009, the Department implemented a drilling stimulus program that impacted the royalties for the year ended March 31, 2011. The first feature was a maximum royalty rate of 5% for the first 50,000 barrels of oil or 500,000 Mcf of gas produced from a well drilled on or after April 1, 2009. The program expired on March 31, 2011.

The second feature was a drilling credit of $200 per metre for wells drilled between April 1, 2009 and March 31, 2011. A sliding scale of 10% to 50% (based on the oil and gas production level of a company) of 2010/2011 natural gas and conventional oil royalties, caps the amount of the credit a company can receive. The program expired on March 31, 2011.

In the fiscal year ended March 31, 2011, natural gas and by-product royalties and conventional oil royalties were reduced by $384,819 (2010 - $197,226) and $486,793 (2010 - $135,625) respectively due to the New Well Royalty Rate feature, while $901,905 (2010 - $786,203) was reduced due to the drilling credit feature.

Note 9 Contractual Obligations

As at March 31, 2011, the Department had commitments totaling $29,900 (2010 - $54,104). These commitments will become expenses of the Department when terms of the contracts are met. Payments in respect of these contracts and agreements are subject to the voting of supply by the Legislature.

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

	Grant Agreements	Service Contracts	Total
2012	$125	$ 19,254	$ 19,379
2013	-	3,056	3,056
2014	-	2,486	2,486
2015	-	2,486	2,486
2016	-	2,493	2,493
Thereafter	-	-	-
	$125	$ 29,775	$ 29,900

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, 2011, the funds in the Oil and Gas Conservation Trust was $3,921 (2010 - $3,806).

DEPARTMENT OF ENERGY
NOTES TO THE FINANCIAL STATEMENTS
(in thousands)

Note 11 Benefits 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 $7,032 for the year ended March 31, 2011 (2010 – $6,136).

At December 31, 2010, the Management Employees Pension Plan reported a deficiency of $397,087 (2009 – deficiency $483,199) and the Public Service Pension Plan reported a deficiency of $2,067,151 (2009 deficiency – $1,729,196). At December 31, 2010, the Supplementary Retirement Plan for Public Service Managers had a deficiency of $39,559 (2009 – deficiency $39,516).

The Department also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2011, the Bargaining Unit Plan reported an actuarial deficiency of $4,141 (2010 – deficiency $8,335) and the Management, Opted Out and Excluded Plan an actuarial surplus of $7,020 (2010 – surplus $7,431). 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 the Energy Industry Drilling Stimulus Program along with eight other 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, 2011, the royalties received under these programs were reduced by $2,440,635 (2010 - $1,465,144).

Note 13 Bitumen Conservation

In 2004-05 the Alberta Energy and Utilities (EUB) Board 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 $57,589 (2010 - $64,115).

Note 14 Approval of Financial Statements

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

DEPARTMENT OF ENERGY **Schedule 1**

SCHEDULE TO FINANCIAL STATEMENTS

Revenues

Year ended March 31, 2011

	(in thousands)		
	2011		**2010**
	Budget	**Actual**	**Actual**
Non-Renewable Resource Revenue (Note 12)			
Bitumen Royalty (Note 7c)	$ 3,249,000	$ 3,723,412	$ 3,160,349
Bonuses and Sales of Crown Leases	630,000	2,634,503	1,164,407
Crude Oil Royalty	2,137,000	2,236,290	1,848,269
Natural Gas and By-Products Royalty (Note 13)	1,861,000	1,415,871	1,525,397
Rentals and Fees	135,000	160,864	157,707
Coal Royalty	35,000	30,508	30,866
Energy Industry Drilling Stimulus Program (Note 8)	(732,000)	(1,773,517)	(1,119,054)
	7,315,000	8,427,931	6,767,941
Freehold Mineral Rights Tax	167,000	127,465	124,466
Other Revenue	500	1,549	38,260
Total Revenue	$ 7,482,500	$ 8,556,945	$ 6,930,667

DEPARTMENT OF ENERGY **Schedule 2**

SCHEDULE TO FINANCIAL STATEMENTS

Expenses - Directly Incurred Detailed by Object

Year ended March 31, 2011

	(in thousands)		
	2011		**2010**
	Budget	**Actual**	**Actual**
Voted			
Grants	$ 100,802	$ 99,312	$ 148,902
Salaries, Wages and Employee Benefits	70,837	67,386	65,127
Supplies and Services	27,553	23,161	21,529
Amortization of Tangible Capital Assets	4,588	6,228	5,491
Financial Transactions and Other	120	116	120
Total Voted Expenses before Recoveries	203,900	196,203	241,169
Less Recovery from Support Service Arrangements with Related Parties [a]	(600)	(535)	(565)
Total Voted Expenses	$ 203,300	$ 195,668	$ 240,604
Statutory			
Valuation adjustments			
Provision for Doubtful Accounts	$ 35	$ -	$ 2
Provision for Vacation Pay	-	257	782
Payments made under the *Mines and Minerals Act*	-	-	3,491
Carbon Capture and Storage	100,000	1,013	538
	$ 100,035	$ 1,270	$ 4,813

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

DEPARTMENT OF ENERGY **Schedule 3**

SCHEDULE TO FINANCIAL STATEMENTS

Comparison of Expenses - Directly Incurred, Equipment/Inventory Purchases (EIP) and Capital Investment, Statutory Expenses, and Non-Budgetary Disbursements by Element to Authorized Budget

Year ended March 31, 2011

	(in thousands)		
Voted Expense, EIP and Capital Investments	**2010-11 Authorized Budget**	**2010-11 Actual**	**Unexpended (Over Expended)**
Program 1 - Ministry Support Services			
1.0.1 Minister's Office	$ 450	$ 449	$ 1
1.0.2 Deputy Minister's Office	511	504	7
1.0.3 Communications	1,234	888	346
	2,195	1,841	354
Program 2 - Resource Development and Management			
2.0.1 Revenue Collection			
- Operating Expense	53,956	55,605	(1,649)
- Equipment/Inventory Purchases	2,315	6,626	(4,311)
2.0.2 Resource Development			
- Operating Expense	41,156	42,922	(1,766)
- Equipment/Inventory Purchases	-	3,700	(3,700)
2.0.3 Biofuel Initiatives	43,000	38,807	4,193
2.0.4 Conservation and Energy Efficiency Initiatives	5,000	-	5,000
	145,427	147,660	(2,233)
Program 3 - Energy and Utilities Regulation			
3.0.1 Assistance to the Energy Resources Conservation Board	57,993	56,493	1,500
	57,993	56,493	1,500
Total Voted Expense, EIP and Capital Investments	$ 205,615	$ 205,994	(379)
Program Operating Expense	$ 203,300	$ 195,668	$ 7,632
Program Capital Investment	2,315	10,326	(8,011)
Total Voted Expenses	$ 205,615	$ 205,994	$ (379)
Statutory Expenses			
Valuation Adjustments			
Provision for Doubtful Accounts	$ 35	$ -	$ 35
Provision for Vacation Pay	-	257	(257)
Payments made under the *Mines and Minerals Act*	-	-	-
Carbon Capture and Storage	100,000	1,013	98,987
	$ 100,035	$ 1,270	$ 98,765

DEPARTMENT OF ENERGY **Schedule 4**

SCHEDULE TO FINANCIAL STATEMENTS

Salary and Benefits Disclosure

Year ended March 31, 2011

	2011				2010
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Deputy Minister (4)	$ 264,576	$ 1,750	$ 63,913	$ 330,239	$ 326,986
Executives					
Chief - Oil Sands Strategy and Operations (5)	50,312	1,750	14,161	66,223	-
Assistant Deputy Minister - Resource Revenue & Operations	175,152	1,750	41,776	218,678	223,580
Assistant Deputy Minister - Electricity & Alternative Energy	185,472	1,750	45,116	232,338	229,771
Assistant Deputy Minister - Resource Development Policy (6)	173,732	1,750	41,777	217,259	38,895
Assistant Deputy Minister - Strategic Services (7)	22,748	1,750	6,837	31,335	-
Assistant Deputy Minister - Strategic Initiatives (8)	185,472	1,750	45,096	232,318	44,105
Co-Chair - Regulatory Enhancement Report (9)	24,255	1,750	7,338	33,343	-
Executive Director - Human Resources	142,752	1,750	34,988	179,490	177,149
Assistant Deputy Minister - Corporate Services (10)	150,897	-	35,347	186,244	217,156
Assistant Deputy Minister - Oil Sands (11)	127,524	-	28,191	155,715	42,005
Executive Lead - Energy Future (12)	130,810	-	30,844	161,654	32,264
Assistant Deputy Minister - Royalty Implementation (13)	-	-	-	-	224,338
Assistant Deputy Minister - Energy Future and Strategic Relations (14)	-	-	-	-	185,830
Assistant Deputy Minister - Energy Policy & Research (15)	-	-	-	-	180,560
Executive Director - Oil Sands Operations (16)	-	-	-	-	160,521

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 and/or lump sum payments. There were no bonuses paid in 2011.

(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, professional memberships and tuition fees.

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

(5) On January 10, 2011, the Deputy Minister announced a revised executive team structure creating this position.

(6) This position commenced on February 1, 2010.

DEPARTMENT OF ENERGY **Schedule 4 (continued)**

SCHEDULE TO FINANCIAL STATEMENTS

Salary and Benefits Disclosure (continued)

Year ended March 31

(7) On February 9, 2011, the Deputy Minister announced a revised executive team structure. This position was occupied by an individual in an acting position.

(8) This position commenced on February 1, 2010.

(9) On February 9, 2011, the Deputy Minister announced a revised executive team structure creating this position.

(10) On February 9, 2011, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(11) This position commenced on February 1, 2010. On January 10, 2011 the Deputy Minister announced a revised executive team structure. This position no longer exists. This position was held by two people during the year; one was an acting position.

(12) On February 9, 2011, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(13) This position no longer exists as of March 31, 2010.

(14) On February 1, 2010, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(15) On February 1, 2010, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(16) On February 1, 2010, the Deputy Minister announced a revised executive team structure. This position no longer exists.

DEPARTMENT OF ENERGY **Schedule 5**

SCHEDULE TO FINANCIAL STATEMENTS

Related Party Transactions

Year ended March 31, 2011
(in thousands)

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

The Department and its employees paid or collected certain taxes and fees set by regulation for permits, 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	
	2011	**2010**	**2011**	**2010**
Accounts Receivable				
ERCB	$ 4,050	$ -	$ -	$ -
APMC	5,193	-	-	-
Accounts Payable	-	-	15,022	-
Expenses - Directly Incurred				
Grants	56,493	67,193	-	-
Other services	2,042	2,021	4	4
	$ 67,778	$ 69,214	$ 15,026	$ 4

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	
	2011	**2010**	**2011**	**2010**
Expenses - Incurred by Others				
Accommodation	$ -	$ -	$ 5,799	$ 6,151
Air Transportation	-	-	607	475
Service Alberta	-	-	4,878	3,358
GOA Learning Centre	-	-	43	130
Legal	-	-	4,125	3,556
Audit	-	-	36	-
	$ -	$ -	$ 15,488	$ 13,670

DEPARTMENT OF ENERGY **Schedule 6**

SCHEDULE TO FINANCIAL STATEMENTS

Allocated Costs

Year ended March 31, 2011

(in thousands)

	2011									2010
		Expenses Incurred by Others						Valuation [8] Adjustments		
Program	Expenses [1]	Accommodation Costs [2]	Transportation Costs [3]	Service Alberta [4]	GOA Learning Centre [5]	Legal Services [6]	Audit Services [7]	Vacation Pay	Total Expenses	Total Expenses
Ministry Support Services	$ 1,841	$ 160	$ -	$ -	$ -	$ 55	$ -	$ 7	$ 2,063	$ 2,467
Resource Development and Management	137,334	5,639	607	4,878	43	4,070	36	250	152,857	185,398
Energy and Utilities Regulation	56,493	-	-	-	-	-	-	-	56,493	67,193
	$ 195,668	$ 5,799	$ 607	$ 4,878	$ 43	$ 4,125	$ 36	$ 257	$ 211,413	$ 255,058

(1) Expenses - Directly Incurred as per Statement of Operations, excluding valuation adjustments.
(2) Costs shown for Accommodation on Schedule 5, allocated by budgeted Full-Time Equivalent Employment.
(3) Costs shown for Air Transportation Costs on Schedule 5, allocated by estimated costs incurred by each program.
(4) Costs shown for Service Alberta costs on Schedule 5, allocated by estimated costs incurred by each program.
(5) Costs shown for Learning Centre on Schedule 5, allocated by estimated costs incurred by each program.
(6) Costs shown for Legal Services on Schedule 5, allocated by estimated costs incurred by each program.
(7) Costs shown for Audit Services on Schedule 5, allocated by estimated costs incurred by each program.
(8) Valuation Adjustments as per Statement of Operations. Employee Benefits and Doubtful Accounts provision included in Valuation Adjustments were allocated as follows:
- Vacation Pay - allocated to the program by employee.

ENERGY RESOURCES CONSERVATION BOARD

FINANCIAL STATEMENTS
For the year ended March 31, 2011

Independent Auditor's Report

To the Members of the Energy Resources Conservation Board

Report on the Financial Statements

I have audited the accompanying financial statements of Energy Resources Conservation Board, which comprise the statement of financial position as at March 31, 2011, 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 generally accepted accounting principles, 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.

Auditors 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 auditors 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 Energy Resources Conservation Board as at March 31, 2011, and its results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Original signed by Merwan N. Saher, CA

Auditor General

May 16, 2011
Edmonton, Alberta

ENERGY RESOURCES CONSERVATION BOARD
STATEMENT OF OPERATIONS
Year ended March 31
(in thousands)

	2011		2010
	Estimates (Schedule 3)	**Actual**	**Actual**
Revenues			
Industry levies and assessments	$ 114,705	$ 115,009	$ 111,368
Provincial grant	57,993	56,493	67,193
Information, services and fees	9,259	7,457	6,670
Investment	2,500	875	596
	184,457	179,834	185,827
Expenses			
Energy regulation (Schedule 1)	161,957	167,313	166,062
Orphan abandonment (Note 3)	13,000	13,094	13,000
	174,957	180,407	179,062
Net operating results	$ 9,500	$ (573)	$ 6,765

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

ENERGY RESOURCES CONSERVATION BOARD
STATEMENT OF FINANCIAL POSITION
As at March 31
(in thousands)

	2011	2010
Assets		
Current		
Cash and cash equivalents (Note 4)	$ 37,055	$ 33,777
Security deposits (Note 5)	43,578	38,557
Accounts receivable	4,415	4,031
Prepaid expenses and other assets	3,677	3,006
	88,725	79,371
Computer software (Note 6)	28,704	30,241
Property and equipment (Note 7)	35,177	15,750
Accrued pension asset (Note 8)	6,621	7,427
Other long-term assets	4,484	547
	$ 163,711	$ 133,336
Liabilities		
Current		
Accounts payable and accrued liabilities	$ 21,421	$ 18,985
Grant payable to Orphan Well Association	10,818	11,919
Security deposits (Note 5)	43,578	38,557
Short-term unearned revenue	454	435
Short-term deferred lease incentives (Note 9)	1,271	428
	77,542	70,324
Long-term unearned revenue	1,163	1,163
Long-term deferred lease incentives (Note 9)	23,730	-
Total liabilities	102,435	71,487
Net Assets		
Net assets, beginning of year	61,849	55,084
Net operating results	(573)	6,765
Net assets, end of year	61,276	61,849
	$ 163,711	$ 133,336

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

ENERGY RESOURCES CONSERVATION BOARD
STATEMENT OF CASH FLOWS
Year ended March 31
(in thousands)

		2011		2010
Operating transactions				
Net operating results	$	(573)	$	6,765
Non-cash items included in net operating results				
Amortization of computer software and property and equipment		15,947		14,752
Pension expense		11,084		7,575
Amortization of deferred lease incentives		(852)		(642)
Changes in operating non-cash working capital				
(Increase) decrease in accounts receivable		(384)		420
(Increase) in prepaid expenses and other assets		(671)		(1,130)
Increase (decrease) in accounts payable and accrued liabilities		2,436		(7,653)
(Decrease) increase in grant payable to Orphan Well Association		(1,101)		3,003
Increase in short-term unearned revenue		19		75
Changes in other long-term assets		(3,937)		844
Reduced rent benefits		4,000		-
		25,968		24,009
Investing transactions				
Investment in computer software		(8,151)		(10,463)
Investment in property and equipment		(4,261)		(5,211)
		(12,412)		(15,674)
Financing transactions				
Pension obligations funded		(10,278)		(7,579)
		(10,278)		(7,579)
Increase in cash and cash equivalents		3,278		756
Cash and cash equivalents, beginning of year		33,777		33,021
Cash and cash equivalents, end of year	$	37,055	$	33,777
Non-cash transactions:				
Additions to property and equipment received as a lease incentive	$	21,425	$	-

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

ENERGY RESOURCES CONSERVATION BOARD

NOTES TO THE FINANCIAL STATEMENTS

(in thousands)

Note 1 Authority and purpose

The Energy Resources Conservation Board (ERCB) is an independent and quasi-judicial agency of the Government of Alberta. The ERCB's mission is to ensure that the discovery, development and delivery of Alberta's energy resources take place in a manner that is fair, responsible and in the public interest. The ERCB operates under the *Energy Resources Conservation Act* , RSA 2000, Chapter E-10.

Note 2 Significant accounting policies

These financial statements are prepared primarily in accordance with Canadian generally accepted accounting principles. Significant accounting policies are summarized as follow:

(a) Revenue recognition

All grants provided by Government of Alberta organizations, industry levies and assessments are recognized as revenue in the period receivable.

(b) Amortization

All tangible and intangible assets with an economic life greater than one year are recorded at cost and are amortized using the following methods:

Computer software - developed	Declining balance - 30 per cent per year
Computer software - purchased	Straight line - 4 years
Furniture and equipment	Straight line - 3 to 20 years
Computer hardware	Straight line - 3 to 5 years
Leasehold improvements	Straight line - lease term

(c) 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 retirement age of employees.

For the purpose of calculating the expected return, plan assets are valued at fair value.

Net accumulated actuarial gain or loss is deferred and amortized over the average remaining service period of the active employees, which is 8 years.

Past service cost arising from plan amendments are deferred and amortized on a straight-line basis over the average remaining service period of active employees at the date of amendment.

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

(d) 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.

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

(in thousands)

Note 2 Significant accounting policies (continued)

(f) Future accounting changes

The Canadian Accounting Standards Board requires all Canadian publicly accountable enterprises to adopt International Financial Reporting Standards for fiscal periods beginning on or after January 1, 2011. As a result, the Canadian Public Sector Accounting Board recommends that other government organizations such as the ERCB adopt Public Sector Accounting standards. Effective April 1, 2011, the ERCB will adopt the Public Sector Accounting standards with retroactive application and restatement of prior period results.

Note 3 Orphan abandonment

The ERCB 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 ERCB grants all of its orphan abandonment revenues (levy and application fees) to the Orphan Well Association. During the year ended March 31, 2011, the ERCB collected $12,274 (2010 - $12,110) in levies and $820 (2010 - $890) in application fees.

Note 4 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, 2011, securities held by the Fund have a time-weighted return of 1.1% per annum (2010 - 1.0% per annum).

Note 5 Security deposits

The ERCB 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, 2011, the ERCB held $43,578 (2010 - $38,557) in cash and an additional $84,315 (2010 - $77,717) in letters of credit. The security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

Note 6 Computer software

	2011			2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Computer software	$ 79,893	$ 57,158	$ 22,735	$ 27,199
Software under development	5,969	-	5,969	3,042
	$ 85,862	$ 57,158	$ 28,704	$ 30,241

Computer software with a net book value of $485 (Cost: $1,202; Accumulated Amortization: $717) with no remaining economic life was decommissioned during the year ended March 31, 2011. A loss of $485 is included in Amortization – computer software on Schedule 1.

(in thousands)

Note 7 Property and equipment

	2011			2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Computer hardware	$ 18,001	$ 10,304	$ 7,697	$ 7,016
Leasehold improvements	33,338	11,041	22,297	2,232
Furniture and equipment	11,095	6,194	4,901	6,220
Land	282	-	282	282
	$ 62,716	$ 27,539	$ 35,177	$ 15,750

Property and equipment with a net book value of $57 (Cost: $4,067; Accumulated Amortization: $4,010) with no remaining economic life was disposed of during the year ended March 31, 2011. A loss of $57 is included in Amortization – property and equipment on Schedule 1.

Note 8 Pension

The ERCB 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. For the year ended March 31, 2011, the expense for these pension plans is equal to the contribution of $8,652 (2010 - $6,767).

In addition, the ERCB 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 date used to measure all pension plan assets and accrued benefit obligations was March 31, 2011. The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2008. The effective date of the next required funding valuation for SEPP is December 31, 2011.

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

	2011	2010
Accrued benefit obligations		
Discount rate	5.8%	6.2%
Rate of compensation increase (weighted average)	3.5%	3.5%
Benefit costs for the year		
Discount rate	6.2%	8.6%
Expected rate of return on plan assets (weighted average)	6.5%	6.5%
Rate of compensation increase (weighted average)	3.5%	3.5%

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

	2011	2010
Fair value of plan assets	$ 31,561	$ 28,497
Accrued benefit obligations	32,902	28,544
Plan (deficit)	(1,341)	(47)
Unamortized net actuarial loss	7,962	7,474
Accrued pension asset	$ 6,621	$ 7,427

(in thousands)

Note 8 Pension (continued)

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

	2011	2010
ERCB contribution	$ 1,626	$ 812
Employees' contribution	395	386
Benefits paid	1,249	851
Pension benefit costs	2,432	808

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

	2011	2010
Equity securities	46.7%	46.5%
Debt securities	41.9%	41.7%
Other	11.4%	11.8%
	100.0%	100.0%

Note 9 Deferred lease incentives

During the year ended March 31, 2011, the ERCB entered into a new lease agreement for its Calgary Head Office. The term of the agreement is twenty years commencing December 1, 2010. The new lease agreement provided for lease incentives totalling $25,425, comprised of leasehold improvement costs in the amount of $21,425 and reduced rent benefits in the amount of $4,000. These amounts are included in deferred lease incentives and are amortized on a straight line basis over the term of the lease.

The following schedule summarizes changes in deferred lease incentives:

	2011			2010
	Leasehold improvement costs	Reduced rent benefits	Total	Total
Balance, beginning of year	$ 428	$ -	$ 428	$ 1,070
Additions during the year	21,425	4,000	25,425	-
Amortization	(785)	(67)	(852)	(642)
Balance, end of year	21,068	3,933	25,001	428
Less: Current portion	(1,071)	(200)	(1,271)	(428)
Long-term portion lease incentives	$ 19,997	$ 3,733	$ 23,730	$ -

ENERGY RESOURCES CONSERVATION BOARD

NOTES TO THE FINANCIAL STATEMENTS

(in thousands)

Note 10 Future operating lease commitments

The ERCB leases office and research storage facilities. The future annual minimum operating lease payments are as follows:

2012	$	6,990
2013		6,828
2014		6,935
2015		6,723
2016		6,964
2017 - 2086		122,234
	$	156,674

Note 11 Related party transactions

For the year ended March 31, 2011, the ERCB paid $5,450 (2010 - $5,323) to various other Government of Alberta organizations for supplies and services. Included in these services was a payment of $4,161 (2010 - $3,937) for computing services and a payment of $48 (2010 - $48) for the lease of a research storage facility from Alberta Infrastructure. The remaining term of this lease is seventy five years.

For the year ended March 31, 2011, the ERCB received a grant of $56,493 (2010 - $67,193) and service revenue of $1,008 (2010 - $319) from Government of Alberta organizations.

All transactions were in the normal course of operations and measured at the amount of consideration agreed to by the related parties.

Note 12 Comparative figures

Certain of the 2010 amounts presented for comparative purposes have been reclassified to conform with the presentation adopted in the current year.

Note 13 Approval of financial statements

These financial statements were approved by the Board of the ERCB on May 16, 2011.

Schedule 1

ENERGY RESOURCES CONSERVATION BOARD
SCHEDULE TO THE FINANCIAL STATEMENTS
Energy Regulation Expenses
Year ended March 31
(in thousands)

	2011	2010
Personnel	$ 105,284	$ 106,312
Consulting services	14,218	16,872
Buildings	11,099	10,395
Amortization - computer software	9,688	9,796
Computer services	9,533	7,713
Amortization - property and equipment	6,259	4,956
Administrative	5,878	4,509
Travel and transportation	3,905	4,025
Abandonment and enforcement	776	809
Equipment rent and maintenance	673	675
	$ 167,313	$ 166,062

ENERGY RESOURCES CONSERVATION BOARD

SCHEDULE TO THE FINANCIAL STATEMENTS

Salaries and Benefits Disclosure

Year ended March 31

	2011				2010
	Base Salary [(a)]	Cash Benefits[(b)]	Non-cash Benefits [(c)]	Total	Total
Chairman	$ 292,685	$ 60,770	$ 10,179	$ 363,634	$ 364,433
Vice-Chairman	201,376	44,592	14,817	260,785	240,060
Board Member 1	180,728	9,042	44,762	234,532	225,830
Board Member 2	180,728	35,555	11,552	227,835	206,375
Board Member 3	180,728	23,676	8,031	212,435	157,107
Board Member 4[(d)]	90,018	2,770	27,022	119,810	-
Board Member 5[(d)]	90,018	-	27,884	117,902	-
Board Member 6[(e)]	87,248	32	20,793	108,073	251,420
Board Member 7[(e)]	87,248	3,448	3,016	93,712	202,851
Board Member 8[(f)]	35,315	-	10,758	46,073	-
Board Member 9	-	-	-	-	197,060

(a) Pensionable base pay.

(b) Payments in lieu of vacation, health, and pension benefits. There were no bonuses paid in 2011.

(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) Appointments effective September 16, 2010.

(e) Appointments rescinded effective September 16, 2010.

(f) Appointment effective December 2, 2010.

Schedule 3

ENERGY RESOURCES CONSERVATION BOARD

SCHEDULE TO THE FINANCIAL STATEMENTS

Authorized Budget

Year ended March 31, 2011

(in thousands)

	Plan			
	Estimates[(a)]	Changes	Authorized Budget	Actual
Revenues				
Industry levies and assessments	$ 114,705	$ -	$ 114,705	$ 115,009
Provincial grant	57,993	(750)	57,243	56,493
Information, services and fees	9,259	-	9,259	7,457
Investment	2,500	-	2,500	875
	184,457	(750)	183,707	179,834
Expenses				
Energy regulation	161,957	(750)	161,207	167,313
Orphan abandonment	13,000	-	13,000	13,094
	174,957	(750)	174,207	180,407
Net operating results	9,500	-	9,500	(573)
Capital				
Capital investment[(b)]	24,200	-	24,200	12,412
Less: Amortization	(14,700)	-	(14,700)	(15,947)
Net capital investment	9,500	-	9,500	(3,535)
	$ -	$ -	$ -	$ 2,962

(a) Estimates are based on the ERCB Business Plan for the year ended March 31, 2011. The Estimates and Changes have been approved by the Treasury Board of the Government of Alberta as the Authorized Budget.

(b) During the year ended March 31, 2011, the ERCB entered into a new lease agreement and received $21,425 in leasehold improvements paid for by the landlord. This amount was capitalized by the ERCB but is not included in the Capital investment in the Authorized Budget as it represents a non-cash benefit to the ERCB and does not have an impact on the ERCB's financial performance.

ALBERTA UTILITIES COMMISSION

FINANCIAL STATEMENTS
For the year ended March 31, 2011

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 Alberta Utilities Commission, which comprise the statement of financial position as at March 31, 2011, 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 generally accepted accounting principles, 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, 2011, and its results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Original signed by Merwan N. Saher, CA

Auditor General

May 10, 2011
Edmonton, Alberta

ALBERTA UTILITIES COMMISSION
STATEMENT OF OPERATIONS
YEAR ENDED MARCH 31
(in thousands)

	2011		2010
	Budget (Schedule 3)	**Actual**	**Actual**
Revenues			
Administration fees	$ 35,528	$ 31,307	$ 30,858
Investment	300	207	163
Dedicated revenue	100	229	144
	35,928	31,743	31,165
Expenses			
Utility regulation (Schedule 1)	36,228	31,601	30,675
Net operating results	$ (300)	$ 142	$ 490

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF FINANCIAL POSITION
AS AT MARCH 31
(in thousands)

	2011	2010
Assets		
Current		
Cash and cash equivalents (Note 3)	$ 11,327	$ 11,806
Accounts receivable	852	201
Prepaid expenses	800	654
	12,979	12,661
Computer software (Note 4)	2,684	2,453
Property and equipment (Note 5)	4,900	5,446
Accrued pension asset (Note 6)	903	871
	$ 21,466	$ 21,431
Liabilities		
Current		
Accounts payable and accrued liabilities	$ 3,987	$ 4,308
Current portion of deferred lease incentive	44	-
	4,031	4,308
Deferred lease incentive	170	-
Total liabilities	4,201	4,308
Net Assets		
Net assets, opening balance	17,123	16,633
Net operating results	142	490
Net assets, closing balance	17,265	17,123
	$ 21,466	$ 21,431

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CASH FLOWS
YEAR ENDED MARCH 31
(in thousands)

	2011	2010
Operating transactions		
Net operating results	$ 142	$ 490
Non-cash expenses		
Amortization	1,867	1,776
Pension	562	178
Changes in operating non-cash working capital		
Increase in accounts receivable	(651)	(75)
Increase in prepaid expenses	(146)	(239)
Decrease in accounts payable and accrued liabilities	(321)	(1,081)
	1,453	1,049
Investing transactions		
Investment in computer software	(1,033)	(641)
Investment in property and equipment	(519)	(617)
	(1,552)	(1,258)
Financing transactions		
Pension obligations funded	(594)	(200)
Lease incentive received	214	-
	(380)	(200)
Net cash used	(479)	(409)
Cash and cash equivalents, beginning of year	11,806	12,215
Cash and cash equivalents, end of year	$ 11,327	$ 11,806

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

ALBERTA UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS

MARCH 31, 2011

(in thousands)

Note 1 Authority and purpose

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, as well as some municipally owned electric utilities, to ensure Albertans receive safe and reliable utility services at just and reasonable rates. The AUC is responsible for making timely decisions on the siting of major natural gas and electric transmission facilities, as well as power plants. It also makes rules about the operation of retail and natural gas electricity markets and adjudicates on market and operational rule contraventions that the Market Surveillance Administrator brings to the AUC.

Note 2 Significant accounting policies

These financial statements are prepared in accordance with Canadian generally accepted accounting Principles. Significant accounting policies are summarized as follow:

(a) Amortization

Tangible and intangible capital assets with an economic life greater than one year are recorded at cost and are amortized using the following methods:

Computer software	Declining balance - 30 per cent per year
Furniture and equipment	Straight line - 3 to 40 years
Computer hardware	Straight line - 3 to 5 years
Leasehold improvements	Straight line - lease term

(b) 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 the expected return, plan assets are valued at fair value.

Any actuarial gain or loss is amortized over the average remaining service period of the active employees, which is 7.5 years.

Past service costs arising from plan amendments are deferred and amortized on a straight-line basis over the average remaining service period of active employees at the date of amendment.

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.

(c) Valuation of financial assets and liabilities

The fair values of accounts receivable, accounts payable and accrued liabilities are estimated to approximate their carrying values. 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.

(d) Revenue recognition

Administration fees are recognized as revenue in the period receivable.

(in thousands)

Note 2 Significant accounting policies continued

(e) Deferred lease incentive

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

Note 3 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, 2011, securities held by the Fund have a time-weighted return of 1% per annum (2010: 1%).

Note 4 Computer software

	2011			2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Computer software	$ 6,637	$ 4,174	$ 2,463	$ 2,453
Software under development	221	-	221	-
	$ 6,858	$ 4,174	$ 2,684	$ 2,453

Note 5 Property and equipment

	2011			2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Furniture and equipment	$ 2,060	$ 477	$ 1,583	$ 1,682
Computer hardware	2,548	1,591	957	1,213
Leasehold improvements	3,206	846	2,360	2,551
	$ 7,814	$ 2,914	$ 4,900	$ 5,446

Property and equipment with a net book value of $2 (Cost: $3 ; Accumulated Amortization: $1) with no remaining economic life was disposed of during the year. Accordingly, a loss of $2 is included in Amortization - property and equipment on Schedule 1.

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 $1,431 for the year ended March 31, 2011 (2010: $1,148).

(in thousands)

Note 6 Pension, continued

In addition, the AUC is a participating member of the defined benefit pension plans of Senior Employees Pension Plan (SEPP) and two supplementary pension plans. These multi-unit pension plans compensate senior staff who do not participate in the government's 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, 2011. The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2008. The effective date of the next required funding valuation for SEPP is December 31, 2011.

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

	2011	2010
Accrued benefit obligations		
Discount rate	5.8%	6.2%
Rate of compensation increase (weighted average)	3.5%	3.5%
Benefit costs for the year		
Discount rate	6.2%	8.6%
Expected rate of return on plan assets (weighted average)	6.1%	6.2%
Rate of compensation increase (weighted average)	3.5%	3.5%

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

	2011	2010
Fair value of plan assets	$ 4,317	$ 3,450
Accrued benefit obligations	4,566	3,607
Plan (deficit) surplus	(249)	(157)
Unamortized net actuarial loss	1,152	1,028
Accrued pension asset	$ 903	$ 871

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

	2011	2010
AUC contribution	$ 594	$ 200
Employees' contribution	102	100
Benefits paid	80	231
Pension benefit costs	562	178

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

	2011	2010
Equity securities	50.8%	44.5%
Debt securities	32.8%	39.5%
Other	16.4%	16.0%
	100.0%	100.0%

ALBERTA UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS

MARCH 31, 2011

(in thousands)

Note 7 Future operating lease commitments

The AUC leases office space with the following future minimum payments:

2012	$	2,651
2013		2,656
2014		2,671
2015		2,739
2016		2,744
Thereafter		5,424
	$	18,885

Note 8 Related party transactions

For the year ended March 31, 2011 the AUC received $191 (2010: $52) of services from, and provided $6 (2010: $6) to other Government of Alberta organizations. These transactions were in the normal course of operations and measured at the amount of consideration agreed to by the related parties.

In addition, the AUC received the benefit of additional services from another government organization in kind with an estimated value of $63 (2010: $0). These contributed services are included in Dedicated revenue on the Statements of Operations and as Consulting services on Schedule 1.

Note 9 Future accounting and reporting

The Canadian Accounting Standards Board requires all Canadian publicly accountable enterprises to adopt International Financial Reporting Standards for fiscal periods beginning on or after January 1, 2011. As a result, the Canadian Public Sector Accounting Board recommends that other government organizations such as AUC adopt Public Sector Accounting standards. Effective April 1, 2011, the AUC will adopt the Public Sector Accounting standards with retroactive application and restatement of prior period results.

Note 10 Approval of financial statements

These financial statements were approved by the Commission of the AUC on May 10, 2011.

ALBERTA UTILITIES COMMISSION Schedule 1

UTILITY REGULATION EXPENSES

YEAR ENDED MARCH 31

(in thousands)

	2011	2010
Personnel	$ 20,135	$ 19,140
Rent and maintenance	4,172	4,192
Computer services	2,112	2,728
Consulting services	2,077	1,521
Amortization - property and equipment	1,065	959
Amortization - computer software	802	817
Administrative	795	843
Travel and transportation	443	475
	$ 31,601	$ 30,675

ALBERTA UTILITIES COMMISSION Schedule 2

SALARIES AND BENEFITS DISCLOSURE

YEAR ENDED MARCH 31

(in thousands)

	2011				2010
	Base Salary [(a)]	Other Cash Benefits [(b)]	Other Non-cash Benefits [(c)]	Total	Total
Chair	$ 320	$ 39	$ 56	$ 415	$ 451
Vice-Chair	201	2	49	252	278
Commission Member 1 [(d)]	181	44	6	231	122
Commission Member 2	181	39	10	230	243
Commission Member 3 [(d)]	181	9	35	225	130
Commission Member 4 [(d)]	181	26	13	220	137
Commission Member 5	181	30	8	219	213
Commission Member 6 [(e)]	114	24	22	160	250
Commission Member 7 [(f)]	66	17	13	96	213

(a) Includes pensionable base pay.

(b) Includes payments in lieu of vacation, health 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) Positions were vacant prior to September 14, 2009.

(e) Position was vacant from September 16, 2010 to February 1, 2011.

(f) Position was vacant from May 14, 2010 to January 4, 2011.

ALBERTA UTILITIES COMMISSION
AUTHORIZED BUDGET
YEAR ENDED MARCH 31, 2011
(in thousands)

Schedule 3

	Plan			
	Budget (Estimate)	**Authorized Changes**	**Authorized Budget**	**Actual**
Revenues				
Administration fees	$ 35,528	$ -	$ 35,528	$ 31,307
Investment	300	-	300	207
Dedicated revenue	100	-	100	229
	35,928	-	35,928	31,743
Expenses				
Utility regulation	36,228	-	36,228	31,601
Net capital investment				
Capital investments	1,500	-	1,500	1,552
Less: Amortization	(1,800)	-	(1,800)	(1,867)
	(300)	-	(300)	(315)
	$ -	$ -	$ -	$ 457

Note:
The Budget is based on the AUC Business Plan for the year ended March 31, 2011. 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, 2010

Independent Auditor's Report

To the Members of the Alberta Petroleum Marketing Commission

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Petroleum Marketing Commission which comprise the statement of financial position as at December 31, 2010 and the statements of revenue and expense 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 generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Petroleum Marketing Commission as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Original signed by Merwan N. Saher, CA

Auditor General

May 24, 2011
Edmonton, Alberta

Alberta Petroleum Marketing Commission
Statement of Revenue and Expense
Year Ended December 31

	(in thousands) 2010	2009
Revenue (Note 1)		
Crude oil sales	$ 1,958,300	$ 1,496,380
Interest earned	140	124
Penalties collected	678	870
Fees on marketing	237	162
Other	7	(8)
	1,959,362	1,497,528
Expense (Note 1)		
Crude oil purchases (Note 2c)	156,177	136,709
Transportation	29,415	26,316
Marketing fees	2,539	2,155
Take or pay charges	877	361
Provision for (Recovery of) Doubtful Accounts	-	(362)
	189,008	165,179
Net operating results before transfer	1,770,354	1,332,349
Amount to be transferred to the Department of Energy (Note 5)	(1,770,354)	(1,332,349)
Excess of revenue over expense	$ -	$ -

The accompanying notes are part of these financial statements.

Alberta Petroleum Marketing Commission
Statement of Financial Position
As At December 31

	(in thousands)	
	2010	2009
Assets (Note 1)		
Cash and short-term investments (Note 3)	$ 15,112	$ 14,435
Accounts receivable	172,746	174,484
Inventory	14,497	21,237
	$ 202,355	$ 210,156
Liabilities (Note 1)		
Accounts payable (Note 4)	$ 37,108	$ 38,961
Liability to the Department of Energy for inventory held	14,497	21,237
Due to the Department of Energy (Note 5)	150,750	149,958
	202,355	210,156
Net Assets (Note 1)	-	-
	$ 202,355	$ 210,156

The accompanying notes are part of these financial statements.

Alberta Petroleum Marketing Commission
Statement of Cash Flow
Year Ended December 31

	(in thousands) 2010	2009
Operating transactions		
Excess of revenue over expense	$ -	$ -
Change in non-cash working capital		
(Increase) decrease in Accounts receivable	1,738	(98,097)
(Increase) decrease in Inventory	6,740	(12,445)
Increase (decrease) in Accounts payable	(1,853)	3,386
Increase (decrease) in Liability to the Department of Energy for inventory held	(6,740)	12,445
Increase in Due to the Department of Energy	792	100,012
Cash provided by operating transactions and net increase in cash	677	5,301
Cash and short term investments at beginning of year	14,435	9,134
Cash and short term investments at end of year	$ 15,112	$ 14,435

The accompanying notes are part of these financial statements.

Note 1 Authority

The Alberta Petroleum Marketing Commission (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 (as represented by the Department of Energy) 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 of Energy 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.

Note 2 Significant Accounting Policies

These financial statements are prepared 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. The PSAB financial statements presentation standard for government summary financial statements has been modified to more appropriately reflect the nature of the Commission.

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) Sales of Crude Oil

Crude oil sales are recognized when crude oil is sold. When producers under-deliver the Department's royalty share, and that under-delivered volume is not subsequently delivered, the Commission deems a sale of crude oil to have occurred. These sales are included in Crude oil sales on the Statements of Revenue and Expense.

(b) Crude Oil Valuation

The Commission has an agency agreement with Nexen Marketing Inc. (Nexen) to market approximately 90% of the royalty share of crude oil. The royalty share is combined with Nexen's supply of like crude. The value of the royalty crude oil is based on a pro-rata share of the net results of Nexen's marketing activities, which may include the sale, purchase, and transportation of crude oil. The Commission currently markets the balance of the royalty share, the results of which are included in Crude oil sales on the Statements of Revenue and Expense.

(c) Inventory

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 crude oil marketing process. Purchased inventory is measured at the lower of cost or net realizable value. Cost for purchased inventory is recorded using the first in first out method.

Inventory for the royalty share is recorded at the lower of cost and net realizable value. The cost of the inventory is the carrying value at which inventory is transferred from the Department to the Commission. Net realizable value is the selling price in the ordinary course of business less the costs necessary to make the sale.

(in thousands)

Note 2 Significant Accounting Policies (continued)

(d) Financial Instruments

Currency, credit and price risks are inherent in the sale and purchase of crude oil. Proceeds of sales by Agents are remitted to the Commission in Canadian funds (Agent sales in foreign currencies are converted to Canadian funds at the average monthly rates for the month of sale.) Proceeds of sale received by the Commission in foreign currencies are valued at average monthly rates for the month of sale. Operational oil price hedging may be used to address 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 3).

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.

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.

The fair values of the Commission's assets and liabilities approximate their carrying values as at December 31, 2010.

Note 3 Cash and Short-term Investments

Cash and short-term investments consist of a deposit in the Consolidated Cash Investment Trust Fund which is managed by Alberta Finance and Enterprise 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, 2010, securities held by the Fund have a rate of return of 0.80% per annum (2009: 1.40%).

Note 4 Accounts Payable

	2010	2009
Transportation and purchases	$ 14,717	$ 14,383
Goods and services tax	22,391	24,578
	$ 37,108	$ 38,961

ALBERTA PETROLEUM MARKETING COMMISSION
NOTES TO THE FINANCIAL STATEMENTS
(in thousands)

Note 5 Due to the Department of Energy

	2010	2009
Due to Department of Energy beginning of year	$ 149,958	$ 49,946
Amount to be transferred to the Department of Energy	1,770,354	1,332,349
Amount remitted to the Department of Energy	(1,769,562)	(1,232,337)
Due to the Department of Energy at end of year	$ 150,750	$ 49,958

Note 6 Commitments

The Commission has entered into transportation agreements for the ensuing one and one quarter years for a portion of its anticipated pipeline requirements. These agreements obligate the Commission to pay tariff charges for contracted volumes in accordance with contracted rates. The aggregate estimated commitment at December 31, 2010 is $9,813 (2009 - $17,986). Due in 2011 – $7,850; and 2012 - $1,963 This commitment will be paid from future oil sales revenue. Costs for these pipeline services are expected to be within the range of normal transportation costs. The Commission also has the option of contracting the space to other shippers.

Note 7 Related Party Transactions

The Department incurs costs for salaries on behalf of the Commission. These costs are not included in the Statements of Revenue and Expense and amount to $1,793.

Note 8 Subsequent Events

Subsequent to December 31, 2010, the Commission announced it had entered into agreements with North West Redwater Partnership (Partnership) to process and market Crown royalty bitumen collected under the Bitumen Royalty in Kind initiative. Development of the bitumen refinery to be constructed by the Partnership is dependent on completion of detailed engineering, final project sanction, and acquisition of necessary financing

Note 9 Comparative Figures

Certain 2009 figures have been reclassified to conform to 2010 presentation.

Note 10 Approval of Financial Statements

The Members of the Commission have approved these financial statements.

POST-CLOSURE STEWARDSHIP FUND

FINANCIAL STATEMENTS
For the four months ended March 31, 2011

Auditor's Report

Statement of Operations

Notes to the Financial Statements

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, 2011 and the statement of operations for the four months 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 generally accepted accounting principles, 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, 2011, and the results of its operations for the four months then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, CA

Auditor General

June 7, 2011
Edmonton, Alberta

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF OPERATIONS

Four Months ended March 31, 2011

Revenue	$	-
Expenses		-
Net Operating Results	$	-

STATEMENT OF FINANCIAL POSITION

As at March 31, 2011

Assets	$	-
Liabilities	$	-
Net Assets		-
	$	-

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND
NOTES TO THE FINANCIAL STATEMENTS

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

The Mines and Minerals Act was amended December 2, 2010 to establish the fund. As a result, only four months of operations is presented.

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.

Additional Information

For additional copies, contact:

Communications Branch
Alberta Department of Energy

11th Floor, Petroleum Plaza North
9945 – 108 Street
Edmonton, Alberta T5K 2G6

Tel: (780) 427-1083
Fax: (780) 422-0698

Information Services
Energy Resources Conservation Board

Suite 1000, 250 – 5th Street SW
Calgary, Alberta T2P 0R4

Tel: (403) 297-8311
Fax: (403) 297-7040

Customer Information Services
Alberta Utilities Commission

Fifth Avenue Place
4th Floor, 425 – First Street SW
Calgary, Alberta T2P 3L8

Tel: (403) 592-8845
Fax: (403) 592-4486

The Ministry of Energy Annual Report 2010-11 is available on the following website:
www.energy.alberta.ca/Org/Publications/AR2011.pdf

Current information about the organizations that were part of the Ministry of Energy in 2010-11 is available at the following websites:

For the Alberta Department of Energy:

www.energy.alberta.ca
e-mail: library.energy@gov.ab.ca

For the Energy Resources Conservation Board:

www.ercb.ca
e-mail: infoservices@ercb.ca

For the Alberta Utilities Commission:

www.auc.ab.ca
e-mail: info@auc.ab.ca

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www.auc.ab.ca

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