GOVERNMENT OF ALBERTA

Annual Report

Energy

2022-2023

Energy, Government of Alberta | Energy 2022-2023 Annual Report

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

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Acronyms and Notations

ABC	Area-Based Closure
ACTL	Alberta Carbon Trunk Line
AER	Alberta Energy Regulator
AGS	Alberta Geological Survey
APIP	Alberta Petrochemical Incentive Program
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels Per Day
CAD$	Canadian Dollar
CAPP	Canadian Association of Petroleum Producers
CBM	Coal Bed Methane
CCLNG	Canada Gas and LNG Exhibition and Conference
CCUS	Carbon Capture, Utilization and Storage
CCS	Carbon Capture and Storage
CEC	Canadian Energy Centre
CER	Canada Energy Regulator
CFR	Clean Fuel Regulation
COVID-19	Coronavirus 2019
CO2	Carbon Dioxide
EOR	Enhanced Oil Recovery
EPA	Environment and Protected Areas
EPO	Environmental Protection Order
ER&T	Emerging Resources and Technology Initiative
ESG	Environmental, Social and Governance
FIS	Field Inspection System
GBE	Government Business Enterprise
GJ	Gigajoule
GRDA	Geothermal Resource Development Act
ha	Hectare
IAR	Integrated Application Registry
IEA	International Energy Agency
IEEP	Incremental Ethane Extraction Program
IRMS	Integrated Resource Management System
JOGMEC	Japanese Organization of Metals and Energy Security
LAMAS	Land Automated Management System
LARP	Lower Athabasca Regional Plan
km	Kilometre
LNG	Liquefied Natural Gas
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MIMTR	Metallic and Industrial Minerals Tenure Regulation
MRDA	Mineral Resources Development Act
NGDDP	Natural Gas Deep Drilling Program
NGTL	TC Energy Corporation's Nova Gas Transmission Ltd.
OECD	Organization for Economic Cooperation and Development
ONS	Offshore Northern Seas (Conference)
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Wells Association
PAA	Plastics Alliance of Alberta
PNG	Petroleum and Natural Gas
REOI	Request for Expression of Interests
RFFP	Request for Full Project Proposals
RNG	Renewable Natural Gas
SCO	Synthetic Crude Oil
SLMS	Safety Loss Management System
SPR	Strategic Petroleum Reserve
SRP	Site Rehabilitation Program
SRT	Structured Review Tool
Tcf	Trillion Cubic Feet
TIER	Technology Innovation and Emissions Reduction
TMF	Tailings Management Framework for Oil Sands Mining Projects
TTFP	Tolls, Tariff Facilities and Procedures
US$	United States Dollar
WCS	Western Canadian Select
WTI	West Texas Intermediate

Preface

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

On October 24, 2022, the government announced new ministry structures. As such, the responsibility for legislation governing the administration of electricity and natural gas utilities in Alberta was transferred from the Ministry of Energy to the Ministry of Affordability and Utilities. The 2022-23 Annual Report reflects the 2022-25 ministry business plans, the Government of Alberta Strategic Plan, and the ministry's activities and accomplishments during the 2022-23 fiscal year, which ended on March 31, 2023.

The annual report of the Government of Alberta contains Budget 2022 Key Results, the audited Consolidated Financial Statements, and Performance Results, which compare actual performance results to desired results set out in the government's strategic plan. This ministry annual report also includes:

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

All Ministry Annual Reports should be considered along with the Government of Alberta Annual Report to provide a complete overview of government's commitment to openness, accountability, and fiscal transparency.

Minister's Accountability Statement

The ministry's annual report for the year ended March 31, 2023, was prepared under ministerial direction in accordance with the *Fiscal Planning and Transparency Act* and the government's accounting policies. All of the government's policy decisions as at June 6, 2023, with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

[Original signed by]

Honourable Brian Jean
Minister of Energy and Minerals

Message from the Minister

The Government of Alberta remains focused on the province's economy to ensure prosperity for all Albertans.

Fiscal 2022-23 was a time of growth and renewal as the energy industry continued to innovate while helping power Alberta, Canada and the world. It continues to evolve into a sector leading the development of emerging, lower-emission energy sources like carbon capture, hydrogen, critical minerals and petrochemicals.

Alberta's world-leading energy industry is critical to growing our resources and diversifying the economy. Over the past year, we have taken steps to support the industry as it has an integral role in meeting energy demands here at home and around the world.

The initiatives undertaken by Alberta Energy included building on opportunities in the traditional oil and gas sector. Extensive advocacy was ongoing for projects that secure additional market access for oil and gas producers, and help protect the value of our province's resources. Engaging with international partners to promote the value of the Alberta's energy resources and explore opportunities in hydrogen, LNG, greater market access and other emerging energy resources was also a priority.

The ministry also continued to implement the new Liability Management Framework to improve and expedite reclamation efforts. It will enable industry to better manage the clean up of oil and gas wells, pipelines and facilities at every step of development and throughout their lifecycles. This will provide more assurance to Albertans that companies will be able to meet their regulatory obligations and ultimately reduce the number of inactive wells which will result in fewer sites becoming orphaned.

The Site Rehabilitation program was a tremendous success. At its completion, approximately $863 million from the Government of Canada's COVID-19 Economic Recovery Plan went into well, pipeline and site clean-up efforts in the oil and gas sector. This work created jobs and ensured that Indigenous businesses and communities had a meaningful role in the post-pandemic energy strategy as partners in prosperity. More than 37,000 wells were approved for at least one activity and of those, over 12,300 were approved for reclamation.

Alberta is a leader in carbon capture utilization and storage (CCUS) and to further our efforts, 25 Carbon Sequestration Evaluation Agreements were signed with industry partners. This gives companies the ability to begin exploring how to safely develop carbon storage hubs. This technology is vital to clean hydrogen development, low carbon oil sands development, petrochemicals and other large emission industries.

The Alberta Petrochemical Incentive Program (APIP) was created to encourage investment in the province and it continues to be successful. There were two grants approved in the last fiscal year, which provided about $194 million to two projects in the Edmonton area. These projects will create hundreds of jobs during construction and staff will also be required for the ongoing operation of the facilities.

Government also proclaimed the brine-hosted regulatory regime and introduced relevant sections of the *Mineral Resource Development Act* to enable the development of critical minerals. Worldwide demand for metals and critical minerals is increasing rapidly in response to growing populations, technological advancement and the global shift towards a lower carbon economy.

Geothermal related regulations and regulation amendments were developed to further enable development and energy diversification throughout the province. Geothermal is natural heat originating from the Earth that can be used for heating and cooling or to generate clean electricity.

We continue to make it easier for companies to do business in our province by reducing regulatory burden. Together with our agencies, we have cut red tape by 24 per cent since 2019 which has resulted in more than $1.3 billion in estimated cost savings for industry. These changes do not reduce the environmental oversight of industry, but helps create cost and time savings. We will continue to participate in the oil and gas industry panel that provides input into reduction initiatives, and also review all submissions from the public.

My thanks to the dedicated and passionate team at Alberta Energy who bring their talent and expertise to the table every day to represent and defend Alberta's interests.

In the year ahead, be assured that government will continue to stand up for the energy sector and Albertans. While there are many musings about the end of fossil fuels, the reality is that the world needs energy now and long into the future.

Reducing emissions and creating a lower-carbon economy is a goal we share with the world. Innovation allows us to evolve and technology allows us to revolutionize how we reduce emissions while continuing to provide energy security here at home and around the world.

[Original signed by]

Honourable Brian Jean
Minister of Energy and Minerals

Management's Responsibility for Reporting

The Ministry of Energy includes:

- Department of Energy,
- Alberta Energy Regulator,
- Alberta Petroleum Marketing Commission,
- Post-Closure Stewardship Fund, and
- Canadian Energy Centre Ltd.

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

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

Responsibility for the integrity and objectivity of the accompanying ministry financial information and performance results for the ministry rests with the Minister of Energy. Under the direction of the Minister, as senior executives, we oversee the preparation of the ministry's annual report, which includes the financial information, performance results on all objectives and initiatives identified in the Ministry Business Plan and performance results for all ministry-supported commitments that were included in the 2022-25 Government of Alberta Strategic Plan. The financial information and performance results, out of necessity, include amounts that are based on estimates and judgments. The financial information is prepared using the government's stated accounting policies, which are based on Canadian public sector accounting standards. The performance measures are prepared in accordance with the following criteria:

- Reliable – information used in applying performance measure methodologies agrees with the underlying source data for the current and prior years' results.
- Understandable – the performance measure methodologies and results are presented clearly.
- Comparable – the methodologies for performance measure preparation are applied consistently for the current and prior years' results.
- Complete – outcomes, performance measures and related targets match those included in the ministry's *Budget 2022*.

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

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

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

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

[Original signed by]

Larry Kaumeyer
Deputy Minister of Energy and Minerals

[Original signed by]

Adrian Begley
Chief Executive Officer
Alberta Petroleum Marketing Commission

[Original signed by]

Laurie Pushor
President and Chief Executive Officer
Alberta Energy Regulator

[Original signed by]

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

June 6, 2023

Results Analysis

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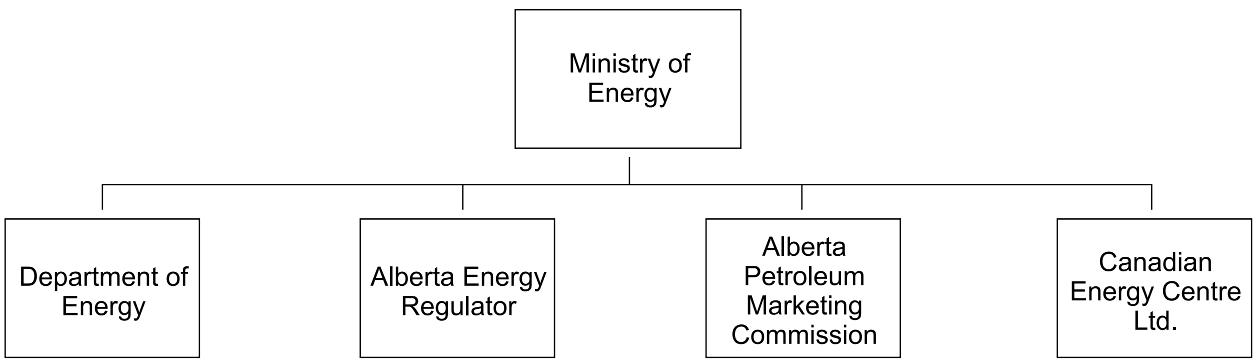
Ministry Overview

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

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

A more detailed description of Energy and its programs and initiatives can be found at www.alberta.ca/energy-and-minerals.aspx.

Organizational Structure



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

The outcomes in Energy's 2022-25 Business Plan are:

- Albertans benefit from economic recovery through investment in responsible energy and mineral development and access to global markets.
- Effective, efficient stewardship and regulation of Alberta's energy and mineral resources.

Department of Energy

- Acts as the steward of Alberta's energy and mineral resources on behalf of all Albertans.
- Develops and administers policies and programs to guide the management and development of Alberta's non renewable resources, including conventional and unconventional oil and gas, oil sands, coal, metallic and industrial minerals, and petrochemicals.
- Ensures the integration of energy and mineral policies and serves as an interface between policy development and policy assurance.
- Grants industry the rights to explore and develop Alberta's Crown-owned energy and mineral resources, subject to regulatory approvals.

- Establishes, administers, and monitors the effectiveness of Alberta's royalty systems for Crown-owned energy and mineral resources.
- Collects revenues from the development of Alberta's energy and mineral resources on behalf of Albertans.
- Leads Alberta's market-access efforts with internal, external, and international stakeholders.
- Administers the carbon capture and storage Post-Closure Stewardship Fund.

Alberta Energy Regulator

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

Alberta Petroleum Marketing Commission

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

Canadian Energy Centre

- Promotes Canada as the supplier of choice for the world's growing demand for responsibly produced energy.
- Responds to misinformation about Canadian oil and natural gas.
- Creates content to improve the general understanding of Canada's energy sector.
- Centralizes and analyses data that targets investors, researchers, and policy makers.

Key Highlights

Alberta continues to advocate across Canada—and globally—to reinforce the important role it plays in providing environmentally responsible, reliable, and affordable energy products to Canadians and the world. Energy is setting an unprecedented path toward a new, innovative, and diversified energy future, while reducing emissions, supporting the development of ground-breaking technology, and encouraging investment. Some key highlights in 2022-23 include:

- Continued advocacy for all projects that secure additional market access for oil and gas producers and help protect the value of Alberta's resources.
- Approval of two grants under the Alberta Petrochemical Incentive Program, which will provide a total of $194 million to two projects in the Greater Edmonton Area and create about 34 permanent jobs and 2,900 during construction.
- Development of geothermal-related regulations and regulation amendments to further enable geothermal development and energy diversification.
- Continued implementation of the new Liability Management Framework as a proactive approach to liability management throughout the life cycle of oil and gas sites, which will provide more assurance that companies will be able to meet their regulatory obligations, reduce the number of inactive wells, and result in fewer sites becoming orphaned.
- Proclamation of the brine-hosted regulatory regime and introducing relevant sections of the *Mineral Resource Development Act* to enable the development of critical minerals.
- Development of 25 carbon sequestration evaluation agreements for carbon storage hub project proposals, following a competitive RFPP process – these will reduce emissions and help to address the growing demand for carbon storage.
- Continued engagement with international partners to promote the value of Alberta's energy resources, to expand market access, and to explore common opportunities in hydrogen, LNG, and other emerging energy resources.
- Completion of the Site Rehabilitation Program, which expensed approximately $863 million from the Government of Canada COVID-19 Economic Recovery Plan into well, pipeline, and site cleanup efforts in the oil and gas sector; created about 4,135 jobs; and ensured that Indigenous businesses and communities played a meaningful role in the post-pandemic energy strategy as partners in prosperity.

Further information on these initiatives can be found in this report's discussion and analysis of results under Outcome One and Outcome Two.

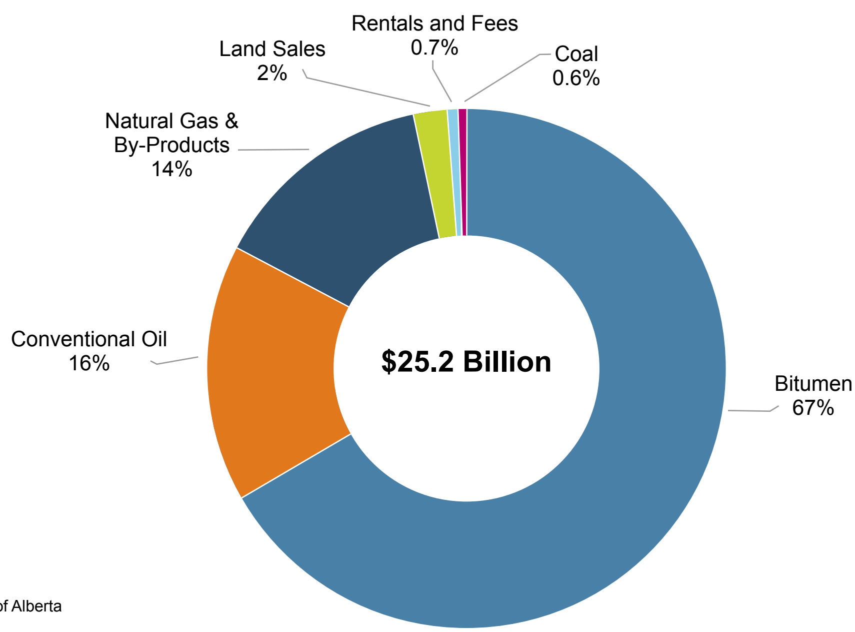
Alberta Energy Resource Sector

Non-Renewable Resource Revenue

Energy development in Alberta provides investment, jobs, business opportunities, taxes, and royalty revenues that fund important government programs for the province. Energy development also drives activity in several other industries, including construction and manufacturing, which benefits communities across Alberta and Canada.

The Department of Energy is responsible for collecting non-renewable resource revenue on behalf of Albertans. Royalties are payments to Albertans for Crown-owned resources that are produced and sold. Albertans, as owners, collect value from our resources through royalties, bonuses, and lease rentals. The price received and the costs involved in producing and selling those resources affect the value available for royalties.

2022-23 Non-Renewable Resource Revenue[1]



Source: Government of Alberta

Non-renewable resource revenues totaled around $25.2 billion in the 2022-23 fiscal year, about $11.4 billion higher than the budgeted amount of $13.8 billion, and $9.1 billion higher than the $16.2 billion collected in 2021-22. The substantial increase in 2022-23 non-renewable resource revenue was the result of a much higher West Texas Intermediate oil price and other oil prices that boosted bitumen and conventional oil royalties. Gas royalties have also significantly increased due to a higher Alberta Natural Gas Reference Price. Higher prices for oil had an upward impact on natural gas liquids prices and gas royalties because prices for natural gas liquids tend to follow oil prices.

Factors Affecting Non-Renewable Resource Revenue

Multiple factors affect non-renewable resource revenue. The most influential factor affecting non-renewable resource revenue is commodity prices; other factors include global economic conditions, economic growth,

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

demand trends, and supply levels. Other factors, such as capital and operating costs, the U.S. and Canadian dollar exchange rate, and production, also affect royalty revenues. Unanticipated changes in these factors can result in significant differences between the budget, forecasts, and the actual results.

Treasury Board and Finance is responsible for forecasting non-renewable resource revenue. The Government of Alberta models the complex system to calculate royalties and forecast non-renewable resource revenue. As part of its analysis to develop price forecasts, the government considers advice from industry consultants, studies the futures market, and analyzes Albertan, North American, and global market trends.

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

Commodity Prices and Trends[2]

Commodity Prices	2022-23 Budget	2022-23 Actual
WTI (US$/bbl)	70.00	89.69
Exchange rate	79.0	75.6
Light-Heavy differential (US$/bbl)	14.30	20.77
WCS (US$/bbl)	55.70	68.91
Alberta reference price for natural gas (CAD$/GJ)	3.20	4.63

Oil Prices

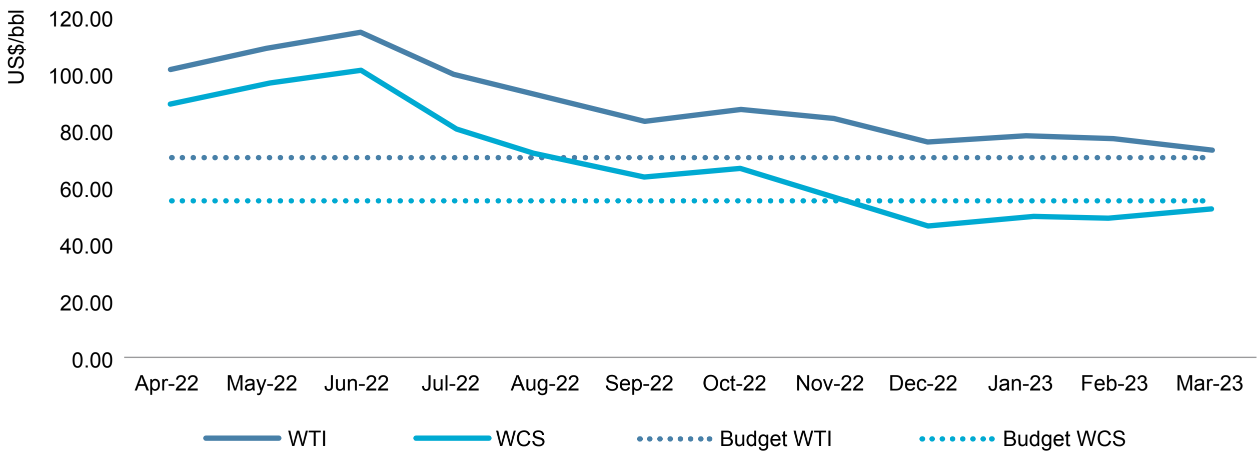
Oil price differences are affected by crude quality (a range from light sweet to heavy sour crudes), location, market demand, and market access for these products. Alberta is landlocked and exports light, medium, and heavy grades of crude oil. Most of Alberta's oil production growth and oil exports are derived from heavy crudes, for which the price per barrel is discounted compared to light sweet oil prices.

Oil prices have remained volatile throughout the year since the invasion of Ukraine by Russia near the end of the 2021-22 fiscal year. China, the world's largest importer of crude oil, maintained a strict zero COVID-19 policy until January 2023, limiting the demand growth for crude oil until near the end of the 2022-23 fiscal year. Meanwhile, Russia's diminished crude production and exports remained above market expectations throughout the 2022-23 fiscal year, despite a series of measures to limit Russian energy exports by the G7 nations and non-G7 European countries. This placed a downward pressure on the price of crude throughout the fiscal year from the high prices observed in the initial months following the invasion.

West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil and is generally reported as the price at Cushing, Oklahoma. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil, and is generally reported as the price at Hardisty, Alberta.

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

2022-23 Crude Oil Prices



Sources: Government of Alberta, Ministry of Energy

WTI 2022-23 trend: Budget 2022 was based on an estimate of US$70.00 per barrel price for WTI crude oil and an exchange rate of 79.0 cents U.S. to the Canadian dollar in 2022-23. The actual WTI price averaged US$89.69 per barrel in 2022-23, with an exchange rate of 75.6 cents U.S. to the Canadian dollar. This was a significant increase from US$77.03 per barrel in 2021-22, primarily due to Russia's invasion of Ukraine, which tightened crude oil supply. Discounted Russian crude imported into the Asian market, particularly by China and India, and release of crude oil from the U.S. Strategic Petroleum Reserve (SPR) put a downward pressure on WTI in the second and third quarters of 2022-23.

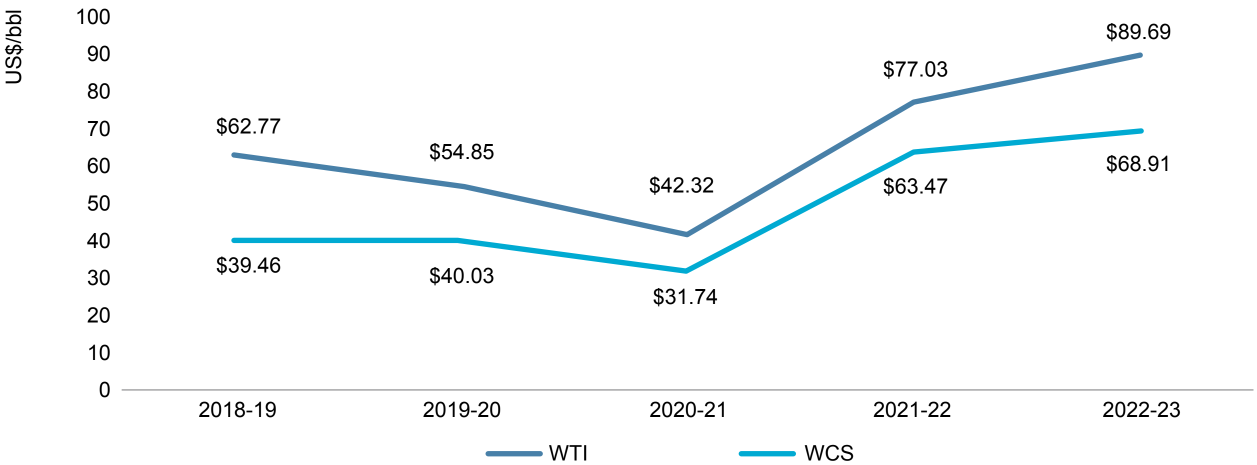
WTI five-year trend: In the fourth quarter of 2022-23, WTI fell to its lowest price since the beginning of Russia's invasion of Ukraine. WTI fell to US$73.37 in March 2023, due to concerns about the health of the U.S. and European banking sectors and generally resilient Russian crude supply despite sanctions.

The International Energy Agency (IEA) indicated in its March 2023 Oil Market Report that global observed inventories for January 2023 were at the highest levels since September 2021, and preliminary February figures suggest further inventory builds, making the crude oil market oversupplied for three consecutive quarters. Inventory builds are driven by stronger than expected Russian crude production, which has remained near pre-war levels despite sanctions. The WTI price is expected to trend upwards in the second half of 2023 as China's crude demand rebounds and exceeds crude supply.

WCS 2021-22 trend: The WCS price was estimated at US$55.70 per barrel for 2022-23 in Budget 2022. WCS price increased significantly to US$68.91 per barrel in 2022-23, as elevated global crude oil prices kept prices for Canadian heavy oil grades relatively high. WCS climbed to its highest price in June 2022 at US$101.17 per barrel, as the global crude oil supply tightened after Russia's invasion of Ukraine. After peaking in June, the WCS price tended downward, reaching its low for the year in December 2022, due to release of heavy crude oil from the U.S. Strategic Petroleum Reserve and intense competition in global markets from discounted Russian crude oil. WCS started a slight upward trend towards the end of the fiscal year, increasing to US$52.99 in March 2023.

WCS five-year trend: The WCS price increased during the 2022-23 fiscal year, with the average annual WCS price settling at US$68.91. The WCS price for 2022-23 was higher than the average annual WCS prices in all other fiscal years during the period from 2018-19 to 2022-23.

Crude Oil Prices



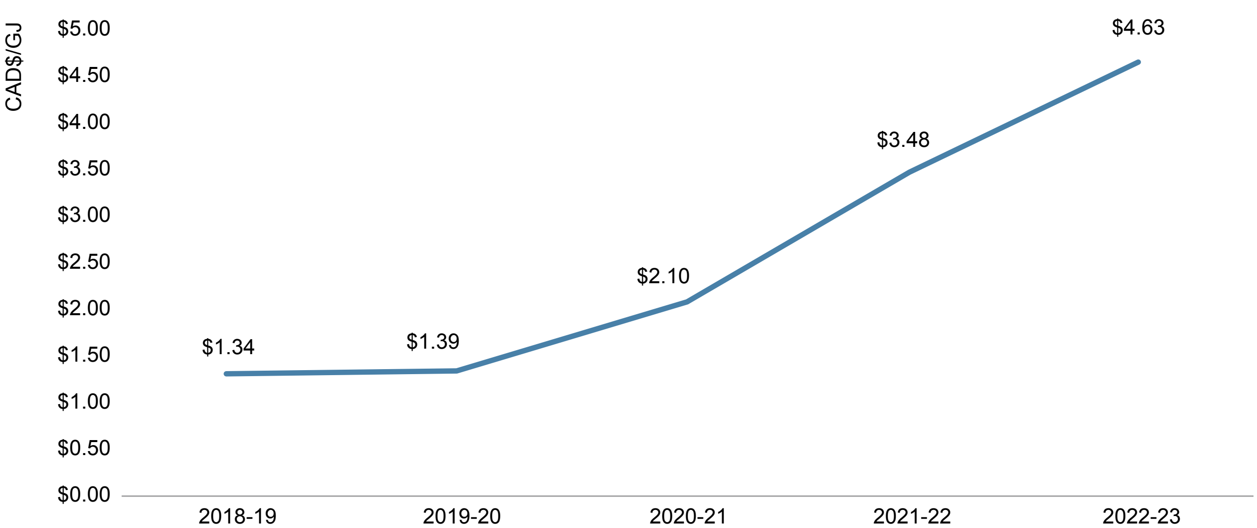
Source: Government of Alberta

The supply growth in Western Canada has not been constrained by takeaway capacity since Enbridge Line 3, which has a total capacity of 760,000 bpd, began operation in October 2021. Pipelines are operating at nearly full capacity until the Trans Mountain Expansion project is completed. Alberta heavy crude exports to the U.S. Gulf Coast have been increasing over time as traditional heavy-crude providers like Venezuela and Mexico export less crude oil to the U.S. The increase of international crude oil prices at the beginning of 2022, driven by intensified geopolitical risks, also significantly pushed up the WCS prices. WCS fell to the lowest monthly level in December 2022, however, due to the release of predominantly heavy crude oil from the U.S. Strategic Petroleum Reserve and intense competition from discounted Russian crude oil in the market. The WCS price was trending upward in the first quarter of 2023, receiving support from the maintenance season and lower crude supply in the U.S. The WCS price ended the 2022-23 fiscal year on an average of US$68.91 per barrel, which is higher than US$63.47 per barrel in 2021-22.

Natural Gas Prices

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

Alberta Gas Reference Prices



Source: Government of Alberta

Overall, the general rule of supply and demand balance determines natural gas prices in North America, with some seasonal variation linked to storage levels and weather conditions. Lower storage levels can lead to higher prices to ensure demand is met through the winter season, and higher storage levels can lead to lower prices if supplies are robust. Lower than normal temperatures in the winter and higher than normal temperatures in the summer can lead to increased natural gas demand and higher prices.

Royalties projected in Budget 2022 were based on a natural gas price forecast of ARP at CAD$3.20/gigajoule (GJ). The realized ARP averaged CAD$4.63/GJ in the 2022-23 fiscal year. The actual natural gas price was above budgeted levels at the end of the fiscal year due to a combination of geopolitical events in Europe, strong domestic and export demand, and colder than usual winter weather conditions that induced strong heating demand.

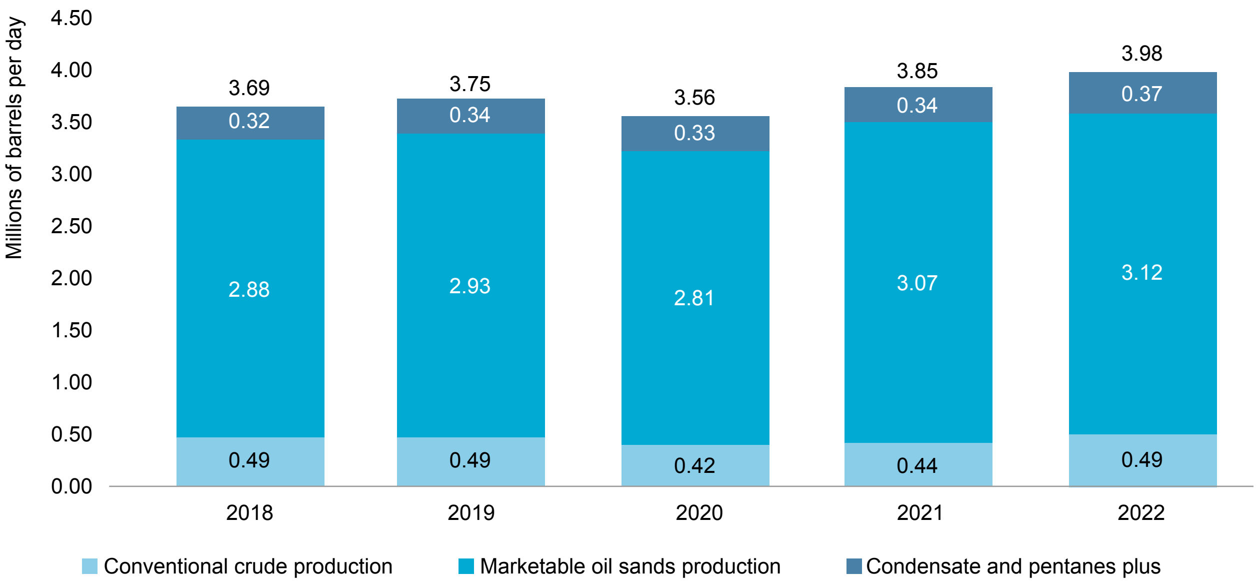
North America is becoming more integrated into global natural gas markets through increasing U.S. liquefied natural gas (LNG) exports, which indirectly affects the Western Canadian natural gas market. Increasing LNG export demand from the U.S. could allow Canadian natural gas supply to fill an emerging supply gap in the North American market; therefore, Alberta's natural gas is well positioned to serve some potentially undersupplied regional markets in the U.S. and Canada.

Production: Performance Indicator 1.b[3]

Alberta Crude Oil and Equivalent Production

Alberta's crude oil and equivalent production consists of conventional crude oil production, condensates, and pentanes plus, and marketable oil sands production, which consists of non-upgraded bitumen and upgraded bitumen.

Alberta Crude Oil and Equivalent Production



Source: Alberta Energy Regulator

[3] Note: Further information about sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 68.

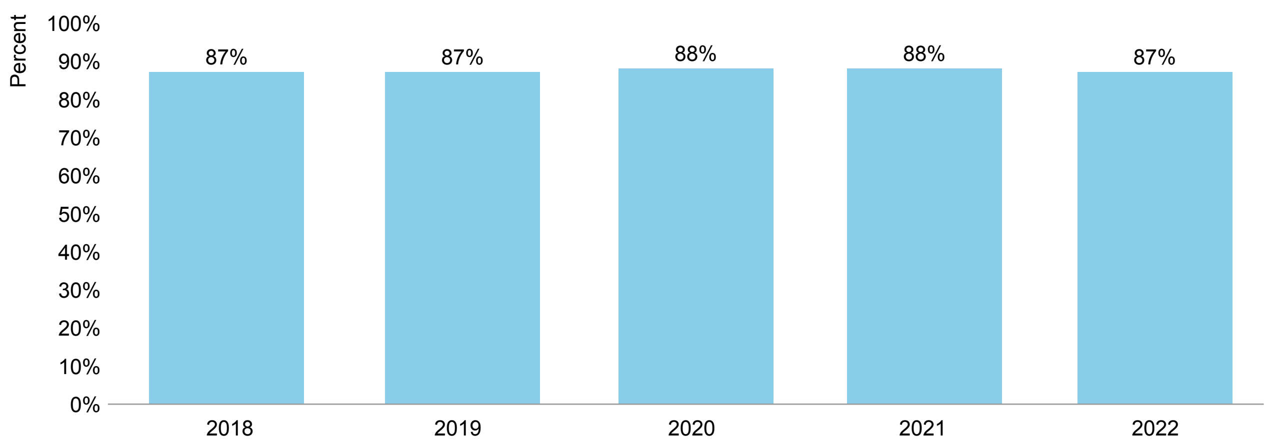
Marketable oil sands production[4] represents a significant majority of Alberta's crude oil and equivalent production. Over the 2018-2022 period, the share of marketable oil sands production in the province remained in the approximate range of 78 to 80 per cent of the total crude oil and equivalent production. In 2020, oil sands production in Alberta declined due to the impacts of COVID-19, which significantly affected crude oil demand in Alberta's traditional market, the United States. In 2021, oil sands production increased by about nine per cent from the 2020 level. The increase took place, as the impacts of COVID-19 in 2021 were less pronounced than in 2020, and the demand for oil experienced some recovery. COVID-19 mitigation measures and safety practices at oil sands facilities were also well in place by 2021, which minimized disruptions and helped to increase production. In 2022, marketable oil sands production reached an annual record of approximately 3.12 million barrels per day (bpd). The increase in marketable oil sands production from 2021 to 2022 was about two per cent. This was significantly smaller than the increase from 2020 to 2021 as the impacts of COVID-19 have further declined since the onset of the pandemic in 2020.

Conventional crude oil production increased from about 0.44 million bpd in 2021 to 0.49 million bpd in 2022. Conventional crude oil production in Alberta remained in the approximate 0.42 million bpd to 0.49 million bpd range during the 2018-2022 period. During this period, production was at its lowest level in 2020 at 0.42 million bpd and peaked at 0.49 million bpd in 2022.

The production of condensate and pentanes plus increased by about six per cent from 2021 to 2022, from about 0.34 million bpd in 2021 to 0.37 million bpd in 2022. During the 2018 to 2022 period the general decreases in condensate production were counter-balanced by increases in the production of pentanes. In 2022, the total production of condensate and pentanes plus in the province reached an annual record level.

Alberta also accounts for a significant majority of Canada's crude oil and equivalent production. According to the Canada Energy Regulator, total Alberta crude oil and equivalent production was estimated to account for about 82.7 per cent of total Canadian production in 2022. This represented an increase from the 2021 share of 81.9 per cent of Canadian production. Over the 2018-2022 period, Alberta's share of Canadian production was at around 80 per cent, ranging from about 80.4 per cent in 2020 to 82.7 per cent in 2022.

Total Percentage of Crude Oil and Equivalent Leaving Alberta



Source: Alberta Energy Regulator

The significant majority of Alberta oil disposition goes to the United States and other Canadian jurisdictions. In 2022, about 87 per cent of Alberta's total crude oil disposition left the province, which is generally in line with the results over the past several years. During the entire 2018-2022 period, the approximate range of crude oil disposition leaving the province was between 87 and 88 per cent.

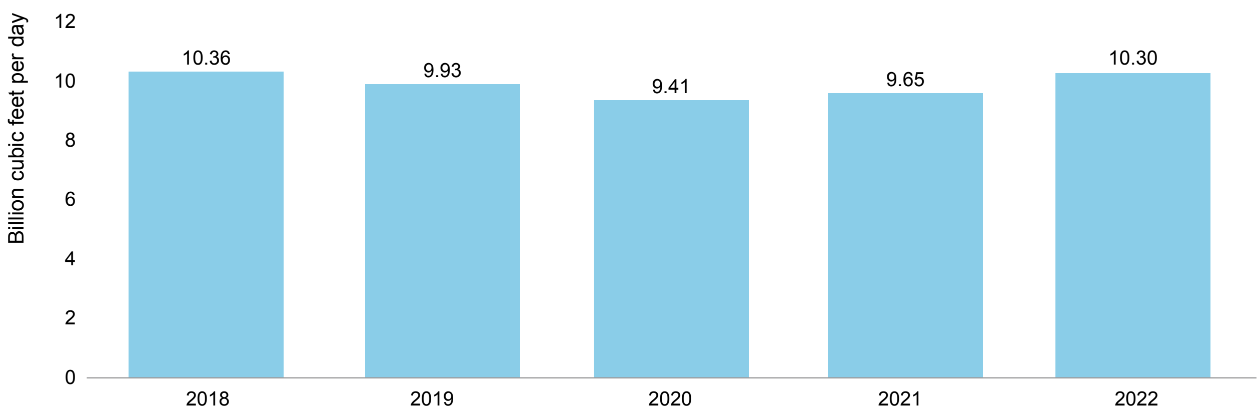
[4] Note: Marketable oil sands production is different from crude bitumen production, as some volumes are reduced during the upgrading process; therefore, the overall marketable oil sands production volumes are lower than overall crude bitumen production volumes.

Of the total crude oil disposition leaving the province, the majority has been going to the United States. In 2021, about 79 per cent of total crude oil disposition went to the United States, with about nine per cent going to the rest of Canada, and about 12 per cent being used in Alberta. This breakdown remained very similar in 2022 – about 79 per cent of total oil disposition went to the United States, eight per cent went to the rest of Canada, and 13 per cent stayed in Alberta.

Natural Gas Production

From 2021 to 2022, Alberta's marketable natural gas production rose by about seven per cent year over year, with an increase of about 0.65 billion cubic feet per day from 9.65 billion cubic feet per day in 2021 to 10.30 billion cubic feet per day in 2022.

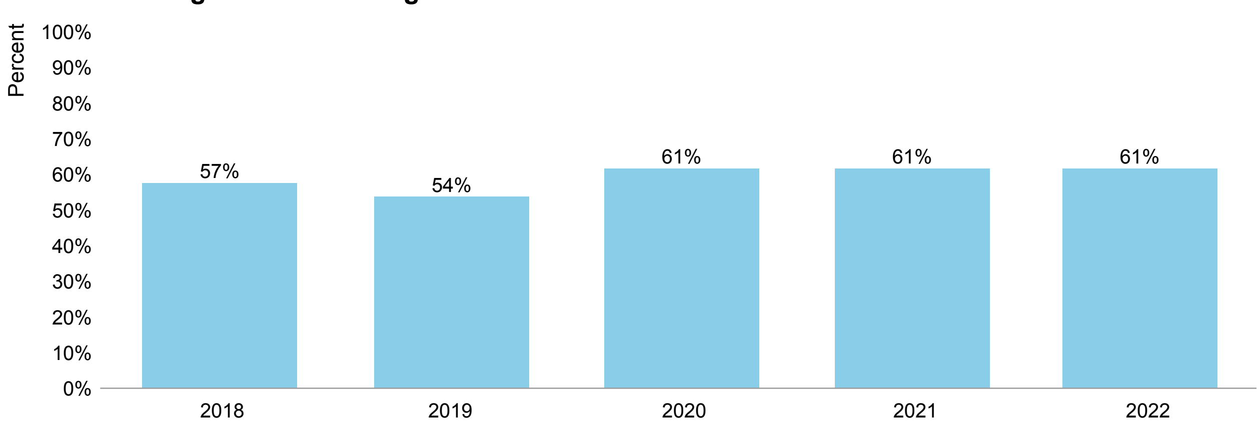
Alberta Marketable Gas Production



Source: Alberta Energy Regulator

The uptick in production in 2022 was mainly due to strong natural gas pricing supported by robust market fundamentals. Natural gas prices were unexpectedly high for most of the year, driven mainly by Russia's invasion of Ukraine in February of 2022 and the economic recovery following COVID-19. As U.S. liquefied natural gas (LNG) exports grew, the highly integrated North American natural gas markets brought positive support to the natural gas sector in Alberta, with some Western Canadian natural gas reaching international markets via at least one U.S. LNG facility during the 2022-23 fiscal year. Overall, the tight market balance from growing natural gas demand in oil sands production, power generation sector, and exports incentivized additional production. Continued pipeline capacity expansions unlocked takeaway capacity in both upstream production and downstream demand sections, which further incentivized production following the strong price signals.

Total Percentage of Gas Leaving Alberta



Source: Alberta Energy Regulator

In 2022, about 61 per cent of Alberta's total gas disposition was exported to the rest of Canada (29 per cent) and the United States (32 per cent).[5] In 2022, the share of gas disposition leaving the province was similar to the share in 2021.

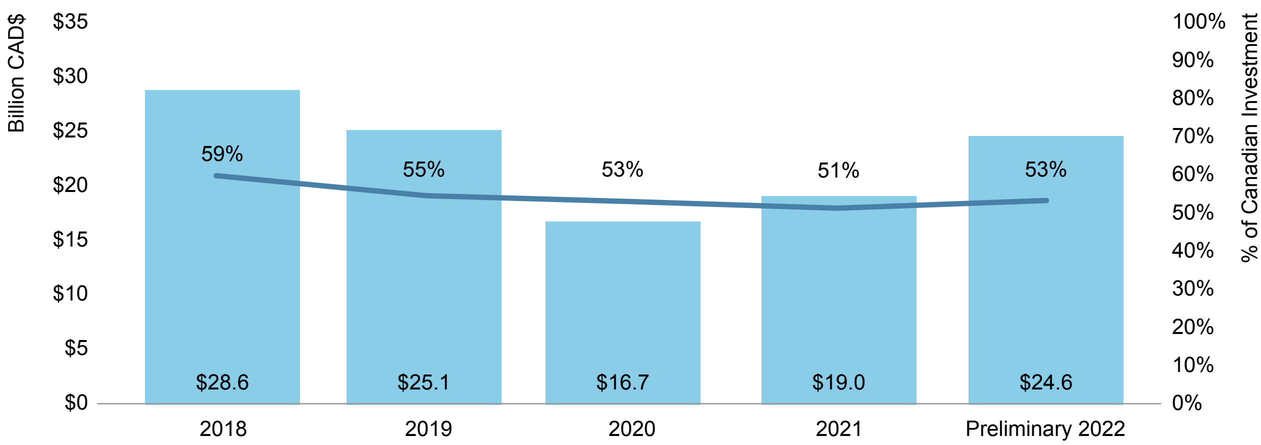
Alberta accounts for a majority of Canada's marketable natural gas production. In 2022, according to the Canada Energy Regulator, Alberta accounted for about 62 per cent of total Canadian production. While Alberta's production level increased from 2021 to 2022, Alberta's 2022 production represented a decline in the national share of production from 62.4 per cent in 2021.

Over the 2018-2022 period, Alberta accounted for approximately two-thirds of Canadian production, ranging from about 62 per cent in 2022 to 65.4 per cent in 2018. Alberta's share of Canadian production was declining every year over the 2018-2022 period, with the share of British Columbia increasing.

Investment: Performance Indicator 1.c[6]

Upstream energy investment in Alberta consists of mining, quarrying, conventional oil and gas investment, oil sands investment, and support activities. Alberta must compete for investment with other oil and gas producing jurisdictions to ensure continuous development of its energy industry.

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



Source: Statistics Canada

The COVID-19 pandemic had a major negative impact on investment in the industry compared to the pre-2020 period. The $16.7 billion investment in 2020 in Alberta's mining, quarrying, and oil and gas extraction sector was at the lowest level for the entire 2006-2021 period, with 2006 being the first year of the capital expenditure data series, which was reported by Statistics Canada.

Total upstream energy industry investment in Alberta for 2021 was $19 billion, accounting for about 51 per cent of the Canadian upstream investment; this result supersedes the preliminary actual result for 2021 that was reported in the 2021-22 Annual Report.

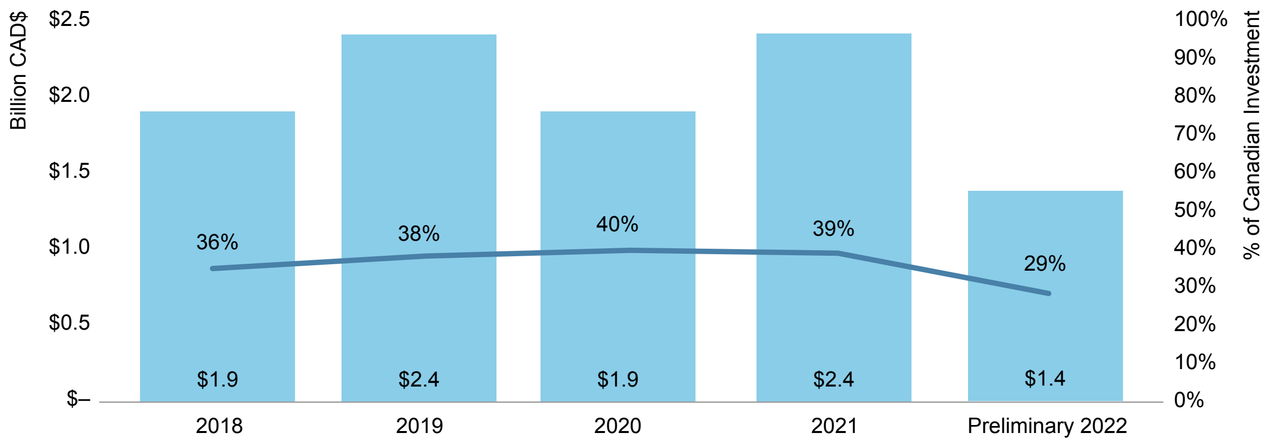
Investment in the mining, quarrying, and oil and gas extraction industry in Alberta was estimated to increase to $24.6 billion in 2022, accounting for 53 per cent of the total Canadian investment in this industry. The increase was driven by the higher returns to investment for industry provided by higher oil and gas prices.

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

[6] Note: Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 68.

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

Capital Investment in Alberta Downstream Sector



Source: Statistics Canada

Overall, the trends that were observed in Alberta for the upstream energy industry investment over the 2018-2022 period did not consistently translate into similar trends for the downstream investment. The smaller downstream capital investment is much more susceptible to significant year over year swings due to major one-time investment decisions that may not actually reflect industry trends. Preliminary results for 2022, at about $1.4 billion, indicate a 44 per cent decrease in Alberta downstream investment from the 2021 level of about $2.4 billion. The 2021 result and actual share reported in the present Annual Report supersede the preliminary actual results reported in the 2021-22 Annual Report. Overall, it is difficult to determine the trend for Alberta downstream investment, which consists of a range of industries with varying manufacturing end products.

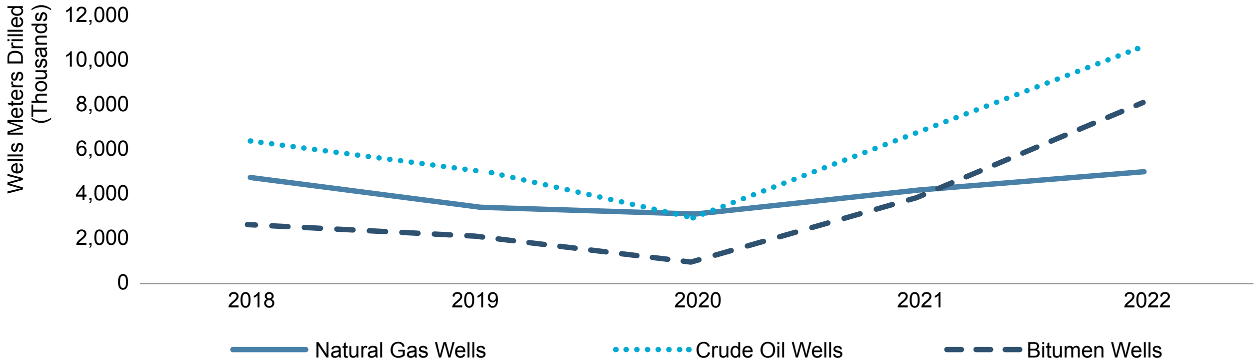
Alberta has one of the most established petrochemical manufacturing centres in Canada, with room for potential growth in new and expanded facilities.

Alberta has a significant opportunity to capitalize on the growing global petrochemical sector, with our abundant natural gas reserves and a competitive, investor-friendly business environment. The Alberta Petrochemicals Incentive Program (APIP) is a key part of the Natural Gas Vision and Strategy to turn the province into a top global producer of petrochemicals. It provides grants to companies to attract investment in new or expanded market-driven petrochemical facilities.

Drilling

Wells drilled include both development and exploratory wells. In 2019 and 2020, drilling activity declined on a year over year basis for all three types of wells (crude oil, bitumen, and natural gas wells), while in 2021 and 2022, the trend reversed, as drilling activity increased for all type of wells.

Wells Meters Drilled



Source: Alberta Energy Regulator

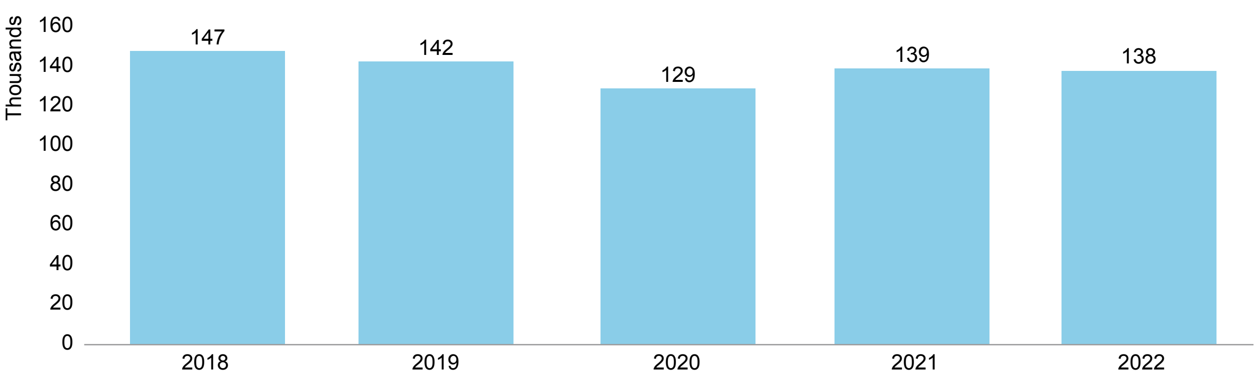
On a year over year basis, drilling activity increased both in 2021 and in 2022. The total successful natural gas wells drilled increased by 19 per cent, from 802 in 2021 to 956 in 2022. Similarly, the total successful crude oil wells drilled increased by 45 per cent, from 2,519 in 2021 to 3,653 in 2022. Bitumen wells drilled experienced a strong upward trend, increasing by 92 per cent from 1,866 in 2021 to 3,580 in 2022. Overall, 2022 was the strongest year for all three types of wells drilled over the entire 2018-2022 period.

Likewise, 2022 was the strongest year for meters drilled during the 2018-2022 period, as the highest total number of meters drilled for all three types of wells occurred in 2022. The year over year increase in the number of meters drilled in 2022 was the highest for bitumen wells, at 102 per cent.

Employment

Employment in the mining, quarrying, and oil and gas extraction sector has been important to Alberta's economic performance. From 2018 to 2019, employment in the sector decreased from 147,000 people to 142,000 people. This trend continued in 2020, when employment in mining, quarrying, and oil and gas extraction declined to 129,000 people due to the impact of COVID-19. In 2021, employment in the sector increased by eight per cent compared to 2020, to 139,000 people employed. In 2022, employment in the sector was virtually unchanged from the previous year, with about 138,000 people employed in the sector.

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



Source: Statistics Canada

Discussion and Analysis of Results

Actions that Support the Priorities of the Government of Alberta Strategic Plan

Key Priority Two:
Growing Alberta's economy

Objective One: Attracting investment and growing the economy

Detailed reporting on the Alberta Petrochemical Incentive Program can be found on page 43.

Objective Four: Standing up for Alberta's natural resources

Detailed reporting can be found on the following initiatives:

- Market Access on page 28
- Pipelines on page 29
- Federal Advocacy on page 30
- Carbon Capture, Utilization, and Storage (CCUS) on page 36
- Environmental, Social and Governance (ESG) on page 45

Objective Five: Advancing a fair deal for Alberta

Detailed reporting on Federal Advocacy can be found on page 30.

Red Tape Reduction

The Ministry of Energy remains committed to regulatory approaches and program delivery that reduce unnecessary government oversight and emphasize outcomes to improve access to government services, attract investment, support innovation and competitiveness, and grow Alberta businesses.

Energy and its agencies achieved a total reduction of 24 per cent in total red tape since 2019. Efforts to streamline regulations in the energy sector led to over $1.3 billion in cost savings for industry, and removing regulatory burden was completed in a manner that maintained environmental, health, and safety protections. Energy continues to engage with industry to determine what improvements can be made, including participating in the Oil and Gas Red Tap Reduction Industry Panel, to share our successes and discuss next steps. The Alberta Energy Regulator (AER) also worked closely with industry on all its changes.

In 2022-23, the Ministry of Energy completed several significant red tape reduction initiatives to address regulatory burdens that benefit the oil and gas industry, including:

- Obsolete oil sands royalty forms were removed from public access, resulting in the removal of over 4,500 regulatory requirements.
- The AER completed updates to its Drilling Waste Management directives, which led to regulatory clarity and consistency for industry, and will create $10.7 million in annual savings that were verified by the Canadian Association of Petroleum Producers (CAPP). It also reduced regulatory requirements.
- Directive 017: Measurement Requirements for Oil and Gas Operations was updated, which created $390 million in one-time CAPP-verified savings for industry through modifying well testing requirements for thermal in situ oil sands operations.
- The AER created new directives for geothermal development and brine-hosted minerals to increase regulatory certainty for investment and job creation in these industries.
- The AER revised 62 regulatory instruments from April 2022 to March 2023.

Other results are integrated throughout this report.

COVID-19/Alberta's Recovery Plan

Alberta's Recovery Plan is a plan to revitalize Alberta's economy and create new opportunities for every Albertan. It's a plan to build, to diversify, and to create jobs. The Government of Alberta launched the plan in June 2020 during a worldwide pandemic, global recession, and collapsing world oil prices. Today, Alberta's economy is on the rebound.

Alberta's energy sector will continue to play a key role in helping to meet the world's post-pandemic energy needs as it enables other emerging sectors to grow and succeed. Energy is setting an unprecedented path towards a new, innovative, and diversified energy future while reducing emissions, supporting the development of ground-breaking technology, and encouraging investment. A key initiative under Alberta's Recovery Plan that advanced these goals in 2022-23 is the Site Rehabilitation Program (SRP).

- The SRP launched on May 1, 2020, providing the oilfield service sector the opportunity to access up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan. It provided relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work.
- At the conclusion of the program, approximately $863 million in grant funding was paid to more than 500 Alberta-based companies. The SRP stopped accepting new applications on March 31, 2022, and the deadline for completing work and submitting final invoices was February 14, 2023.

More information regarding the Site Rehabilitation Program can be found in this report's discussion and analysis of results under Outcome Two, on page 49.

Outcome One:

Albertans benefit from economic recovery through investment in responsible energy and mineral development and access to global markets.

The ministry develops and manages policies and programs related to the province's royalty system to attract industry investment and to provide jobs, business opportunities, tax revenue, and numerous other benefits to the provincial economy. It advocates for increased pipeline and takeaway capacity to access global markets to strengthen both provincial and national economies, while proactively communicating how Alberta produces energy with the highest environmental, labour, and human-rights standards in the world. It seeks to influence challenges facing the natural gas sector, including those related to market access, price volatility, and intra- and interprovincial natural gas transportation and storage.

Key Objectives

1.1 Support the competitiveness of Alberta's energy industry by maximizing and protecting its energy resource sector while enabling and accelerating opportunities in emerging resources, by:

- reducing red tape to Alberta's energy sector while streamlining legislative requirements and regulatory processes;
- continuing to invest in environmental stewardship through site rehabilitation;
- advocating and supporting expanded pipeline takeaway capacity and access to new markets for Alberta's energy resources and products;
- continuing to implement the natural gas vision and strategy, including opportunities in liquefied natural gas, investments in petrochemical manufacturing, creating conditions for deployment of hydrogen across the provincial economy, and development of the circular plastics economy; and
- continuing to create a competitive regulatory environment that encourages the development of natural gas, hydrogen, geothermal, minerals, and advancing the development of carbon capture, utilization, and storage to leverage Alberta's natural advantages.

Market Access

The Government of Alberta supports proposals for, and the development of, projects that can unlock new markets for Alberta's resources, including oil and gas and new mineral production. Every credible forecast of future world energy consumption sees oil and gas continuing to dominate the supply mix for the next several decades. The ministry continues to vigorously advocate on behalf of Albertans and Canadians whose livelihoods depend on it and to engage with the Government of Alberta's counterparts in the federal government to market Canada's responsible and affordable energy.

As a result of global events, including Russia's invasion of Ukraine and the subsequent escalation of energy prices around the world, there is a renewed focus on continental and global energy security and the need to get Alberta's strategic oil and gas resources to market. With the province's abundant crude oil and natural gas reserves, Alberta is uniquely positioned to help Canada, the U.S., and countries around the world reduce reliance on energy from hostile or undemocratic regimes and ensure safe, secure, reliable, and affordable energy supply chains. Alberta is positioning itself as a reliable energy source to meet the demands of global markets that might otherwise import energy from less environmentally and socially conscious jurisdictions.

The Government of Alberta is advocating for all projects that secure additional market access for oil and gas producers, and help protect the value of Alberta's energy resources, through:

- intervening in all regulatory and legal proceedings where the province has standing;
- pursuing the concept of economic corridors and monitoring project proposals to improve market access;
- continuing to advocate for existing pipelines, including Line 5 and the Trans Mountain Expansion Project;
- participating in intergovernmental forums to build support for Alberta's energy resources, including the Energy Council, Offshore Northern Seas Conference, North American Energy Security Roundtable, and Oslo Energy Forum; and
- meeting with investors and attending industry events globally to promote Alberta's energy sector, including CERAWeek.

Pipelines

Alberta currently has more than 4.5 million barrels per day (bpd) of oil pipeline takeaway capacity. Oil production in the province is expected to continue to increase in future years, which will require more pipeline takeaway capacity to match increased production. Alberta's pipeline access expanded in late 2021 with the start-up of the Enbridge Line 3 Replacement Project, which provided an additional 370,000 bpd to the U.S. market. Additionally, the Trans Mountain Expansion Project is expected to provide an additional 590,000 bpd of capacity from Western Canada and is anticipated to begin serving the U.S. and Asia Pacific markets in early 2024. The Department of Energy continues to leverage strategic stakeholder relationships to support the long-term objective of exporting Alberta's energy resources to emerging global markets and growing our export capacity to existing North American markets. In 2022-23, this work included a specific focus on Enbridge's Line 5 pipeline, the Trans Mountain Expansion Project, and recouping Alberta's investment in the Keystone XL pipeline.

Trans Mountain Expansion Project

The Trans Mountain Expansion Project is the twinning of an existing 1,150-kilometre pipeline between Strathcona County, Alberta, and Burnaby, British Columbia. Nominal system capacity will increase from approximately 300,000 barrels per day to 890,000 barrels per day.

In March 2023, Trans Mountain Corporation announced that the project will achieve mechanical completion in late 2023 and enter service in the first quarter of 2024. The company also announced that total projected costs increased from $21.4 billion to $30.9 billion. The estimated cost increases are a result of high global inflation; supply chain challenges; the preservation of culturally significant sites and artifacts for Indigenous Peoples; project enhancements; impacts of the November 2021 floods in B.C.; and delays associated with building major projects in demanding geography, densely populated areas, and challenging weather conditions.

As of March 2023, construction on the Trans Mountain Expansion Project is approximately 78 per cent complete. According to Trans Mountain Corporation, approximately 25 per cent of total contracts were awarded to Indigenous businesses as of March 2023. The contracts are worth more than $4.8 billion and employ over 3,000 Indigenous workers.

Enbridge Line 5

Energy continued to support and advocate for Enbridge in legal cases against Line 5, which is a vital component to the Enbridge Mainline system. Line 5 is crucial to the energy supply and economies of both the U.S. and Canada and has operated safely and reliably for decades. It is a critical source of propane and crude oil supply to Ontario, Quebec, Michigan, and the broader Great Lakes Region. It also provides reliable energy jobs and economic benefits on both sides of the border. In 2020, Enbridge was notified that the State of Michigan intended to revoke and terminate the 1953 easement, which allows the company to operate its dual pipelines in the Straits of Mackinac. Enbridge's legal challenges, and Treaty discussions initiated by the Government of Canada are expected to take years to resolve. Energy supported alignment efforts with Enbridge, the Government of Canada, affected provinces, and other stakeholders, prior to the matter going to trial in late October 2022. The precedent of a safely operated, fully regulated pipeline being pulled out of service has broad implications for existing and future energy projects.

Keystone XL

An investment agreement was reached in March 2020 between the Alberta Petroleum Marketing Commission (APMC), on behalf of the Government of Alberta, and TC Energy to financially support the construction of the Keystone XL pipeline project. Alberta's investment in this project was linked to our province's long-term economic interests.

An Executive Order signed by President Joe Biden, in January 2021, revoked the Presidential Permit for the cross-border pipeline, resulting in TC Energy suspending activity on the pipeline and initiating a divestment process for Keystone XL assets. An agreement was reached to provide APMC proceeds from disposition of certain Keystone XL assets. For the current fiscal year, APMC has received approximately $64 million from the sale of Keystone XL assets, bringing the cumulative liquidation proceeds to approximately $102 million.

In February 2022, the Government of Alberta, through the APMC, filed a notice of intent to initiate a legacy North American Free Trade Agreement claim under the Canada-United States-Mexico Agreement over the cancellation of the presidential permit for the Keystone XL pipeline border crossing. The claim will seek to recover no less than $1.3 billion of the government's investment.

Economic Corridors

An economic corridor is a designated area that provides vital links to markets, in and out of Alberta, to support economic, social, and environmental activity. Economic corridors may include various types of infrastructure and the coordination of regulation and policies across multiple jurisdictions to support the delivery of products and services to new markets. Infrastructure in economic corridors may include railways, transmission lines, highways, and pipelines.

Alberta is interested in pursuing cross-jurisdictional corridors for a variety of products, including oil and gas, hydrogen, electricity, and new mineral production. There are significant benefits of a western energy corridor, which would allow Alberta oil to reach new markets in Europe and Asia. Designated corridors could also reduce future opposition to projects by aiming to set aside lands for economic purposes before a specific project is contemplated.

Alberta is actively monitoring several proposed corridor projects, including the Port of Churchill, the First Peoples Pipeline, and the Western Energy Corridor. While several companies have explored the idea of shipping oil from Alberta to the Port of Churchill, these projects are at the conceptual stage, no private sector applications having been submitted to federal or provincial regulators.

Federal Advocacy

Energy advocates for Alberta's oil and gas market interests through participation in industry committees, Canada Energy Regulator (CER) proceedings regarding federally regulated energy infrastructure and service applications, and the Energy–CER working table. This work communicates provincial interests within CER processes and supports Energy's objectives to strengthen market access for Alberta's natural resources. In 2022-23, this included:

- intervening at the CER hearings to advance Alberta's interests in the Nova Gas Transmission Ltd. (NGTL) West Path Delivery 2023 project and NorthRiver Midstream NEBC Connector Project;
- continuing to participate in industry committees, such as the Enbridge Mainline Committee; NGTL Tolls, Tariff Facilities and Procedures subcommittee (TTFP); and TransCanada Mainline Toll Task Force; and
- regularly monitoring oil and gas facilities applications before the CER and the Impact Assessment Agency of Canada.

Opportunities in emerging resources (e.g., hydrogen), geopolitical shifts, and increasing concerns regarding energy security, energy prices, and climate change, are ongoing developments that will likely lead to evolving regulatory frameworks in Canada, the U.S. and overseas, which may impact Alberta's market interests. Energy will continue to advocate for improving Alberta's market access as trends and new developments evolve.

Clean Fuel Regulation (CFR)

The final version of the federal CFR was published in the Canada Gazette on July 6, 2022. The CFR targets carbon emission reductions in liquid hydrocarbon fuels, such as gasoline and diesel used for transportation, and aims to spur innovation and economic growth in the low-carbon fuels sector. Alberta remains concerned about:

- the impacts to low-income households;
- the potential for lost revenue to the Crown through decreased demand for refined petroleum products, such as gasoline and diesel;
- the federal government's decision to exclude exported crude and finished products from credit opportunities;
- increasing costs and compliance burden for the energy sector;
- the potential transfer of investment and capital from Alberta to other jurisdictions; and
- the lack of flexibility associated with using CFR credits or compliance fund options, which are otherwise needed to ensure the CFR can effectively adapt to unforeseen market changes.

Federal Engagement on Sustainable Jobs Plan[7]

In 2022-23, Energy supported Executive Council to develop Alberta's final response to the federal government regarding the Sustainable Jobs Plan and provided an analysis of industry reactions. The Government of Canada aims to ensure a just and equitable transition to a low-carbon future for workers and their communities. On February 17, 2023, the federal government released the interim Sustainable Jobs Plan, which will guide the federal government's approach from 2023 to 2025. The plan will be revised every five years, beginning in 2025, and includes the establishment of a new training centre for sustainable jobs and a new government advisory body.

Federal Consultation on Oil and Gas Emissions Cap

Environment and Climate Change Canada launched formal engagement on two potential regulatory options to cap and reduce oil and gas sector greenhouse gas emissions. In 2022-23, Energy continued to support the

[7] The Government of Canada defines the term "Sustainable Job" as "any job that is compatible with Canada's path to a net-zero emissions and climate resilient future." The term is also intended to reflect "the concept of decent, well-paying, high-quality jobs that can support workers and their families over time and includes such elements as fair income, job security, social protection, and social dialogue."

Ministry of Environment and Protected Areas to develop analysis of related federal policies, such as the *Impact Assessment Act* and Best-In Class Guidance Document, in preparing Alberta's final response to the federal government.

International Missions

Sustained and coordinated engagement to build mutually beneficial relationships is critical to reinforce the importance of Alberta energy products to the North American energy system and to promote Alberta's strong environmental, social, and governance (ESG) record. International and Alberta-based engagements in 2022-23 include:

- **Offshore Northern Seas (ONS) Conference:** Minister Savage held bilateral meetings with key European stakeholders and participated in the ONS conference in Norway, discussing how member countries develop infrastructure together and take advantage of synergies based on conventional energy, in co-existence with wind, hydrogen, and carbon capture, utilization, and sequestration infrastructure.
- **ATB Conference:** Minister Savage attended the ATB Capital Markets' Fall Energy Conference in New York.
- **North American Energy Security Roundtable:** Minister Savage and Dr. Daniel Yergin, Vice Chair of S&P Global co-hosted a roundtable in Washington D.C. to discuss maintaining safe and secure global energy supplies, bolstering supply chain resilience, and promoting a North American energy alliance.
- **Energy Council Banff Energy and Environmental Issues Conference:** Minister Guthrie participated in the Energy Council's conference in Banff, which focused on North American energy security opportunities and challenges, and met with several key U.S. stakeholders.
- **Minister of Energy's Stakeholder Roundtables:** Minister Guthrie met with the leaders of Alberta-based energy companies in Calgary in January 2023 at four roundtables focused on sharing government's priorities and learning about the perspectives of industry, focused on oil, natural gas, liquified natural gas, hydrogen, petrochemicals, critical minerals, and geothermal.
- **Mission to Norway and Germany:** Minister Guthrie spoke about opportunities in hard-to-abate sectors at the Oslo Energy Forum in Norway and held meetings with several stakeholders to discuss innovation in the energy sector, investment opportunities, and energy security. The delegation also promoted Alberta's gas resources in Germany, to enhance European gas security.
- **CERAWeek 2023:** Minister Guthrie spoke in March at CERAWeek 2023 in Houston, Texas and held meetings with key U.S. and international stakeholders to discuss energy security, market access, and investment opportunities..

The total cost for out-of-province travel for the official delegations in 2022-23 was approximately $166,724. This includes all travel and hosting costs for the delegations during out-of-province engagements.

Minerals Strategy

The Minerals Strategy and Action Plan will help ensure that Alberta:

- has the opportunity to be at the forefront of global mineral exploration and development;
- can exploit untapped geological potential to meet the increasing demand for minerals;
- has the potential to develop several critical mineral resources, including lithium, vanadium, rare earth elements, titanium, and uranium, to help meet clean-energy demand; and

- has Indigenous community and Indigenous business participation in critical-minerals development and resource partnerships.

In December 2021, the Government of Alberta passed the *Mineral Resource Development Act* (MRDA), establishing the Alberta Energy Regulator (AER) as the full life-cycle regulator for Alberta's metallic and industrial mineral resources.

As part of targeted engagement from 2020 to 2022, Energy engaged stakeholders regarding elements of the Minerals Strategy and Action Plan, lifecycle mineral regulation, and tenure modernization. This included an AER-led virtual public information session in May 2022 about minerals to discuss the future regulation of brine-hosted minerals and stakeholder and industry group engagements, between June and October of 2022, to collect feedback and inform the development of the regulatory instruments for brine-hosted minerals.

The Government of Alberta has made a significant investment in the mapping of targeted public geoscience information in Alberta. As part of Budget 2021, $28 million was earmarked for geothermal resource development and the Minerals Strategy, including mapping of targeted public geoscience information in Alberta and support for the AER to establish the regulatory frameworks for geothermal and minerals. Budget 2022-23 included an additional $41 million over three years to support the expanded mandate of the AER. Some of the funding is being used to improve mineral mapping information: Alberta's critical minerals remain largely unmapped and unexplored, and widely available maps will help facilitate mineral mining development and good decisions.

The Government of Alberta modernized the tenure regime for metallic and industrial minerals. On January 1, 2023, the new Metallic and Industrial Minerals Tenure Regulation (MIMTR) came into force. The new regulation provides for a separate management of brine-hosted and rock-hosted minerals.

Under this new regulation, rights to brine-hosted and rock-hosted minerals will be issued under different agreements with different tenure requirements. Energy has taken a phased approach to enable a smooth transition and implementation of the MRDA. Energy is nearing completion of the implementation of the MRDA, the first of the two phases having been completed.

- **Phase 1: Brine-Hosted Minerals Development:** The brine-hosted regulatory regime was proclaimed on February 28, 2023, and sections of the MRDA relevant for brine-hosted minerals, as well as new and amending regulations, came into force on March 1, 2023. On March 15, the Brine-hosted Mineral Resource Development Rules came into effect, and the new Brine-hosted Mineral Resource Development Directive (090) was published on aer.ca; these set out the requirements that industry must follow throughout the entire life cycle of a brine-hosted mineral resource development. As of March 16, the AER can accept applications for brine-hosted mineral development in OneStop.
- **Phase 2: Rock-Hosted Minerals Development:** Energy is currently working on the transition of regulatory functions from Environment and Protected Areas (EPA) to the AER. Energy continues to work with partner agencies (EPA; Forestry, Parks and Tourism; Indigenous Relations; Justice and

Brine- and Rock-hosted Minerals

Brine-hosted metallic and industrial minerals are solid substances or elements extracted from soluble components naturally dissolved in groundwater. Rock-hosted metallic and industrial minerals are substances and elements that are not brine-hosted and are generally extracted from solid rocks and sediments. Metallic and industrial minerals include diamonds, gold, iron, limestone, salt, and other precious stones and metals. This does not include oil, gas, oilsands, coal, ammonite shell, or surface materials such as sandstone, sand, and gravel.

Solicitor General; and many others) to bring forward the required regulations for phase 2 of the MRDA implementation.

On March 2, 2023, the Government of Alberta announced the addition of helium to the list of potential critical minerals in Alberta to recognize its importance to support further diversification of the energy sector and the creation of new jobs. Alberta's proximity to the U.S.—the world's largest helium consumer—underlines the opportunity that helium development presents. Alberta has potential for helium deposits in the southeast part of the province.

Alberta continues to work collaboratively with the federal government and other provincial and territorial governments through various initiatives such as the Pan-Canadian Geoscience Strategy, Canada's Critical Mineral Strategy, and many others. Alberta is encouraged by recent federal funding for the critical-minerals sector, including a $27-million contribution to E3 Lithium, which will support the construction of a demonstration plant specializing in lithium production in the province.

Maps to Minerals Program

To support Alberta's Minerals Strategy and Action Plan, the objective of the Alberta Energy Regulator's (AER) multi-year Mineral Mapping Program is to collect new information and data to improve the characterization and understanding of Alberta's mineral potential. The data and information products produced from this work will be used to highlight new areas of mineral potential that may stimulate exploration and development, which in turn supports potential investment and job creation in Alberta. The overarching objective is to improve the access to transparent and reliable geological and mineral data and information products to provide a better understanding of Alberta's diverse mineral resource potential. More detail is laid out in the vision presented in Renewing Alberta's Mineral Future.

The program includes the collection and public release of raw data, interactive maps, technical reports, journal publications, and public presentations.

Data acquired by AGS under the Mineral Mapping Program as of March 31, 2023, includes:

- airborne geophysics,
- core scanning,
- rock sampling,
- historical record digitization,
- remote sensing imagery over Clear Hills and Grand Prairie, and
- oil field and groundwater sampling from 312 oil and gas wells.

Did you know?

The Alberta Geological Survey (AGS) conducted an airborne geophysics program between 2021 and 2023. Airborne geophysics is an environmentally friendly way to survey large areas, as it does not disturb the land. The Airborne Geophysics project is one of the largest single-acquisition airborne geophysical survey acquisitions in Canadian history. This project represents the largest mineral data acquisition (in both scale and scope) in Alberta's history.

In 2022-23, the AER updated its mineral resource webpages on ags.aer.ca to add data and improve ease of access so the public can choose the data it wants to visualize and download. In addition, in March 2023, the AER published six overview documents regarding major project thematic areas highlighting the data that was collected, how it improves understanding of Alberta's mineral potential, and where data was collected. The AER also published three datasets, including:

- raw data publication from 248 brine samples;
- airborne geophysics magnetic and gravimetric maps; and
- whole-rock geochemical analysis for 2,423 samples of plutonic and metamorphic rock.

Geothermal

Prior to a geothermal legislative framework, there was a gap in policy defining geothermal energy and guiding development, which led to regulatory uncertainty. Industry, academics, and other stakeholders highlighted the importance of clear legislative and regulatory requirements in order to have the certainty required to advance deep geothermal projects. The Government of Alberta proclaimed the *Geothermal Resource Development Act* (GRDA) in December 2021, covering deep geothermal resources occurring below the base of the groundwater protection. The act established the Alberta Energy Regulator (AER) as the single life-cycle regulator for the safe, efficient, and responsible development of geothermal resources in Alberta, clarifies industry requirements and grants the government ability to receive revenues, such as royalties and fees, for geothermal development.

Under the GRDA, the Geothermal Resource Development Regulation was brought into force in January 2022, along with several rules and amendments to other regulations that were needed to enable the development of geothermal resources. This includes the AER's Geothermal Resource Development Rules and consequential amendments to the Oil and Gas Conservation Rules in June 2022. With the new regulatory framework and supporting systems and processes for geothermal resource development in Alberta complete, companies are now able to progress to the next stage of development.

Between January 2022 and March 31, 2023, the Government of Alberta received 74 applications for tenure and issued 32 leases; additionally, there are currently four projects in advanced planning or demonstration phases in Alberta. Pilot projects in Alberta have received over $50 million in funding from several sources, including Natural Resources Canada and Alberta Innovates. These supports will advance geothermal projects, create new jobs, and support innovation that will help position Alberta itself as a leader in geothermal technology development and exports. Eavor Technologies Inc. is one example of an Alberta-based company leading innovation that has the potential to improve the competitiveness and scalability of geothermal development. In October 2022, Eavor began the construction of its first commercially operated Eavor-Loop system in Germany, which is supported by the German government and European Union. This culminates technology developed and demonstrated in Alberta and tested in the southwestern U.S.

Did You Know?

Geothermal energy is natural heat from the Earth, which may be used for heating, electricity, industrial processes, or co-produced with other minerals and hydrocarbons. Alberta has a competitive advantage that is not available to many geothermal producers globally. This includes access to innovative drilling technologies, a highly developed oil and gas skilled labour force, and a robust subsurface data set, which are essential components to a successful geothermal industry. Research from the University of Alberta has identified the potential to develop this resource on a commercial scale with over 6,100 megawatts of thermal power capacity potential and over 1,150 megawatts of technically recoverable electrical power capacity potential across several municipal districts in western Alberta.

Energy will continue to follow its guiding principles to further support geothermal development in Alberta. These principles include:

- minimizing impacts to existing surface and subsurface agreement holders;
- establishing a clear regulatory pathway to access resources through surface and subsurface;
- preserving regulatory flexibility and discretion while providing clarity and certainty for industry and stakeholders; and
- where possible, aligning rules and regulations for geothermal resource activities with similar activities and government policies.

Carbon Capture, Utilization, and Storage (CCUS)

For large stationary sources of Carbon Dioxide (CO2), like gas-fired generating units and petroleum refineries, use of CCUS can help redirect CO2 emissions before they enter the atmosphere. Captured CO2 is injected into locations deep underground for safe, permanent storage. CCUS is a necessary, developing part of reducing emissions, and the government recognizes the value that CCUS will bring to Alberta, playing a critical role in a low-carbon economy.

Large scale CCUS development requires significant investment to develop and operate, which highlights the importance of attracting CCUS investment to accelerate the deployment and retain Alberta's position as a global leader in the technology. CCUS incentives provided by the American *Inflation Reduction Act* have made development in the United States attractive for industry. Energy has been working with the federal government to provide more financial supports for CCUS projects, maintain Alberta's competitiveness, and attract investment. Energy also worked with other ministries and organizations, such as Invest Alberta and domestic and international companies, to attract carbon capture investment and opportunities to export Alberta's CCUS technologies and expertise.

The Alberta Petrochemical Incentive Program (APIP), which provides grants to new hydrogen and petrochemical projects in Alberta, requires a CCUS component for projects that produce hydrogen or fuels from natural gas sources. The Air Products Hydrogen Production and Liquefaction Facility in Edmonton was the first hydrogen project to meet this requirement. The use of the net-zero hydrogen produced in the facility in these downstream markets will result in overall full life-cycle CO2 emissions reductions of approximately 1.4 million tonnes per year. The facility is expected to be completed in late 2024.

2008 Carbon Capture and Storage Program

In 2008, the Government of Alberta committed $2 billion to establish the Carbon Capture and Storage (CCS) Program Fund to incentivize the development of CCS large-scale projects in Alberta. Two projects decided to proceed with their plans: the Quest and the Alberta Carbon Trunk Line projects. $1.24 billion in funding is allocated for the two projects to capture approximately up to 2.76 million tonnes of CO2 each year until the end of 2025. This is roughly equivalent to annual emissions of 600,000 vehicles. Over the 2022-23 fiscal year, annual injection payments for the Alberta Carbon Trunk Line and the Quest projects totaled approximately $42 million. The amount of the greenhouse gas emission reductions is certified by third party verifiers.

Post-Closure Stewardship Fund:

The Post-Closure Stewardship Fund is administered by the department and financed by carbon-capture and storage operators in Alberta. The fund will help ensure that storage sites are properly maintained over the long term, after operations cease, and to offset the costs of the government's obligations, particularly in the post-closure period. The operators that obtain a lease under the Carbon Sequestration Tenure Regulation are required to contribute to the fund. The amount paid into the fund is based on a project-specific rate per tonne of CO2 injected into the sequestration lease each year.

A review and update of the Post-Closure Stewardship Fund rate for the Quest project took place in 2022, and the new rate took effect October 1, 2022. To date, the Post-Closure Stewardship Fund has collected seven annual injection levy payments from the Quest project, and with $447,000 in revenues generated from the injection levy during 2022-23, the fund is currently valued at $2.17 million.

The Quest project is currently the only carbon sequestration project paying into the Fund. Since the Alberta Carbon Trunk Line is an enhanced oil recovery project, it holds a conventional PNG lease and does not pay into the Post-Closure Stewardship Fund.

Quest Project Update: The Quest project is capturing approximately a million tonnes of CO_2 per year from the Shell Scotford Upgrader, transporting it 65 kilometres north by pipeline, and permanently storing it underground in a deep saline aquifer. The Quest project completed its seventh year of CO_2 injection. Since entering operation in 2015, the project has exceeded its targets for the capture and safe, permanent storage of CO_2 at a lower-than-anticipated cost. Shell Canada Energy, the project operator for the Quest project, has noted that the project has captured and stored over seven million tonnes of CO_2.

Alberta Carbon Trunk Line Update: The Alberta Carbon Trunk Line (ACTL) project is transporting over one million tonnes of CO_2 per year, captured from the Sturgeon Refinery and the Nutrien Redwater Fertilizer Plant, through a 240-kilometre pipeline for use in enhanced oil recovery in Clive, Alberta. The pipeline has the potential to transport up to 14.6 million tonnes of CO_2 annually. Since entering operation in 2020, ACTL has completed its second year of CO_2 injection. Enhance Energy Inc., the sequestration site operator for the ACTL, has noted that the project has captured and sequestered over 3.5 million tonnes of CO_2.

CCUS Tenure Management

The department has received significant interest from industry for the right to use pore space for the sequestration of CO_2. The pore space used for CCUS requires secure underground geological formations that can safely and permanently store the captured CO_2. Ensuring a well-defined and strategic approach to make sure CO_2 storage options are available and accessible to all industries is essential to meet current and future demand.

The province is advancing a strategic hub concept through a competitive process. A carbon sequestration hub will be an area of pore space overseen by a private company that can effectively plan, enable, and undertake carbon sequestration of captured CO_2 from various emissions sources as a service to industrial clients. Having an industry steward of the location, with the oversight of Alberta's regulatory system, will work toward efficient use of the pore space and support strong modelling, monitoring, and risk management practices.

Energy issued two Requests for Full Project Proposals (RFPP) for carbon sequestration hubs in Alberta, the first in in December 2021 which resulted in six successful proposals in the Industrial Heartland region, and the second in March 2022, which resulted in an additional 19 successful proposals being selected in October 2022 from regions across Alberta.

Following the RFPPs, Energy developed 25 Carbon Sequestration Evaluation Agreements for the successful carbon storage hub project proposals and collected approximately $9.6 million in Evaluation Agreement rental fees. The agreements allow companies to work with the government to further evaluate the suitability of their locations for safely storing carbon from industrial emissions. Throughout the evaluation process, companies are expected to identify and address potential conflicts with other subsurface interests and undertake various regulatory approvals, consultation and business development activities. Operators will also be responsible to obtain regulatory approvals from the Alberta Energy Regulator for the capture, transportation, and subsurface injection activities of CO_2. Alberta's CCUS regulatory approval process requires careful site selection, numerous approvals, rigorous monitoring and reporting requirements, and public involvement processes.

If the evaluation demonstrates that the proposed projects can safely provide permanent storage, companies will be invited to work with the government on an agreement that provides them with the right to inject captured CO_2. When fully developed, the hubs will allow operators to safely collect, transport and permanently store captured CO_2 from industrial emissions sources across the province.

Between February and March 2023, Energy also engaged with stakeholders to better understand other CCUS opportunities to complement the development of the storage hubs. These opportunities include small-scale

CCUS and sequestration in remote locations. Based on this work, learnings may be used to inform potential RFPPs in the future.

For more information, visit: https://www.alberta.ca/carbon-capture-utilization-and-storage-hub-development-process.aspx

Sturgeon Refinery

Sturgeon Refinery commenced commercial operation on June 1, 2020 and began processing bitumen into diesel with a capacity of 79,000 barrels per day (bpd) of feedstock, increasing Alberta's total refinery capacity to 533,000 bpd.

The Sturgeon Refinery continues to work to maximize operating cash flows while maintaining safe and reliable operations and is processing an average of approximately 75,000 bpd of feedstock, producing approximately 40,000 bpd of ultra-low sulphur diesel for both Alberta and Western Canada. In addition to producing one of the cleanest low-carbon diesels in North America, the refinery is also the world's only refinery designed from the ground up with an integrated carbon-capture solution.

In addition to the APMC being a 75 per cent Tollpayer, in June 2021, the APMC became a 50 per cent owner in Sturgeon Refinery, improving oversight and governance in the refinery's operations, maintenance, engineering, scheduling and optimization, thereby providing stewardship over Albertans' investment in the refinery. As a Tollpayer, the APMC provides 75 per cent of the feedstock and receives 75 per cent of the refinery sales at the Sturgeon Refinery.

During the 2022-23 fiscal year, the refinery underwent its first major planned turnaround, with processing capacity being offline from early August and to mid- October. During this first scheduled turnaround, activities focused on catalyst replacements and equipment repair in all refinery units. The scheduled turnaround was a major milestone for the refinery.

As of March 2023, approximately 2.8 million tonnes of carbon were captured since the start of commercial operations in June 2020.

Further details on the refinery's performance can be found on the APMC website at www.apmc.ca and the North West Redwater Partnership website at www.nwrsturgeonrefinery.com

Site Rehabilitation Program (SRP)

The SRP launched on May 1, 2020, providing the opportunity to access up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan. It provided relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work.

At the conclusion of the program, approximately $1 billion in grant funding was approved and allocated to more than 562 Alberta-based companies. The SRP stopped accepting new applications on March 31, 2022. The deadline for completing work and submitting final invoices was February 14, 2023. To maximize program benefits, the Government of Alberta requested an extension of program deadlines from the Government of Canada. In response, the Government of Canada provided a 45-day extension that allowed for more time to process applications, complete the work, and submit invoices at the end of the program. This extension required that Alberta make all SRP funding commitments by May 15, 2022. Any funding not committed to approved applications is to be returned to the Government of Canada.

The $1-billion grant funding was made available in eight funding periods, each with targeted priorities, application criteria, and timelines. The information below is current to March 31, 2023, but does not represent final totals for the SRP.

	Priorities and Criteria	Funding*
Period 1: May 1, 2020, to May 15, 2020	Grant applications were accepted for oil and gas sites needing abandonment or reclamation across Alberta for projects that required 100 per cent government funding with contracts of up to $30,000 per application per closure activity. As the period two was not fully subscribed, $83 million of available funding was reallocated to period one, and a total of $183 million in funding was allocated.	Allocated: $183 million Approved: $163.79 million Paid: $139.4 million
Period 2: May 15, 2020, to June 15, 2020	Grant applications were accepted for oil and gas sites on land where government is paying compensation to landowners as required under Section 36 of the *Surface Rights Act* for projects that require 100 per cent government funding with no contract cost limits.	Allocated: $17 million Approved: $11.76 million Paid: $8.2 million
Period 3: June 17, 2020, to March 31, 2021	Grant applications were accepted for up to $139,000 in funding for each active site licensee in the province. Oil field service contractors could contract with the licensees to do closure work and apply for an SRP grant to obtain funding. The grants were eligible for 100 per cent funding.	Allocated: $100 million Approved: $57.06 million Paid: $53.1 million
Period 4: August 7, 2020, to March 31, 2022	Grant applications were accepted for licensees who submitted either confirmed or proposed Area-Based Closure plans to the Alberta Energy Regulator. Projects were eligible for up to 50 per cent grant funding, the licensee being responsible for paying the remaining costs. Grant funding was increased up to 100 per cent of the project value if the licensee contracted with Indigenous oil field service companies.	Allocated: $100 million Approved: $99.24 million Paid: $91.6 million
Period 5: February 2021 to March 31, 2022	Licensees with confirmed hydrocarbon production in 2019 and that had spent corporate funds doing closure work in 2019 or 2020 were allocated SRP grant funding amounts for period five. Projects were eligible for up to 50 per cent grant funding. Grant funding was increased up to 100 per cent of the project value if contracted with Indigenous oil field service companies. In January 2022, the period-five allocations were increased by a third for a total of $400 million in available funding, using underutilized funds from existing periods.	Allocated: $400 million Approved: $374.94 million Paid: $326.8 million
Period 6: February 12, 2021, to March 31, 2022	First Nations and Métis Settlements were allocated a portion of $85 million and $15 million in SRP closure funding, respectively. Funding supported work with licensees and applicants to close sites on reserves and settlements. In January 2022, the period-six allocations were increased by a third for a total of $133 million in available funding using estimated-to-be-underutilized funds from previous periods.	Allocated: $133 million Approved: $125.06 million Paid: $107.5 million
Period 7: August 9, 2021, to March 31, 2022	Funding was made available for post-abandonment closure work on two categories of sites: those abandoned prior to April 30, 2017, and nominated sites with abandoned wells, facilities, or pipelines abandoned prior to April 30, 2017. Projects were eligible for up to 50 per cent grant funding. Grant funding was increased up to 100 per cent of the project value if contracted with Indigenous oil field service companies.	Allocated: $100 million Approved: $83.02 million Paid: $70.9 million

	Priorities and Criteria	Funding*
Period 8: August 9, 2021, to March 31, 2022	Funding was made available for closure work in Sage Grouse, native trout, and caribou Species at Risk geographic areas identified. One-third of the $100 million in funding was allocated to each of the three Species at Risk (Sage Grouse, native trout, and caribou). Projects for post-abandonment work activities were eligible for up to 100 per cent grant funding. Abandonment projects were accepted within the identified Sage Grouse area and were eligible for up to 50 per cent of grant funding.	Allocated: $100 million Approved: $85.14 million Paid: $65.4 million

Paid amounts represent totals to March 31, 2023, and estimates of remaining amounts to be paid, but accrued to the current fiscal, and do not represent final program spending.

As of March 31, 2023, a total of $1 billion was approved and $863.0 million was expensed, enabling 562 Alberta-based companies to create over 4,135 jobs. Broken down by application type, this includes:

Activity**	Approved applications	Completed applications	Funding approved (MM)	Funding paid (MM)
Abandonment	17,731	17,514	$563.4	$476.7
Phase 1 Environmental Site Assessments	3,414	3,406	$20.9	$20.4
Phase 2 Environmental Site Assessments	4,561	4,542	$93.4	$84.0
Reclamation	8,134	8,048	$235.4	$203.7
Remediation	1,790	1,775	$86.9	$78.3
Total	*34,979	*34,642	$1,000	$863.0

* Applications can have multiple activities, and the total applications is not a sum of individual activities.

** Activities prior to December 2020 are estimated based on asset-level approved amounts and cumulative grant payments. They were approved and tracked as lump-sum grants, which could have contained multiple activities.

For more information, visit https://www.alberta.ca/site-rehabilitation-program.aspx

Hydrogen Roadmap

Hydrogen is a clean fuel that only produces water and heat when combusted. It can be used for heating, power generation and storage, transportation, and industrial processes. Alberta's abundant natural gas resources, favourable geology for carbon capture, and experience producing hydrogen present a unique opportunity for the province to be an early adopter of clean hydrogen and position itself as a global supplier to facilitate clean-energy transition.

The Government of Alberta released its Hydrogen Roadmap in November 2021 to help Alberta reach its strategic goals related to hydrogen. Alberta is striving to have large-scale hydrogen production with carbon capture, utilization, storage, and deployment in various commercial applications across the provincial economy by 2030. Its goal is to have exports of clean hydrogen and hydrogen-derived products, such as ammonia, to jurisdictions across Canada, North America, and globally by 2030. The roadmap outlined five leading markets for hydrogen end-use opportunities, including:

- heating,
- power generation and storage,
- export,
- transportation, and
- industrial processes.

Following the announcement of the roadmap, Energy began developing policy and legislative amendments to enable these key growth markets, which are currently ongoing. Overall, there is approximately $16.8 billion worth of hydrogen investment in various stages of development in Alberta.

Hydrogen Blending

In March 2022, the Government of Alberta issued an Order in Council directing the Alberta Utilities Commission (AUC) to conduct an inquiry into matters relating to hydrogen blending into natural gas distribution systems and report to the Minister of Energy. On June 30, 2022, the to the Minister of Energy and subsequently released the report publicly. Following the report's release, Energy, in partnership with Environment and Protected Areas, hosted an engagement session on hydrogen and renewable natural gas (RNG) blending in the utility market. Observations from the report and Energy's stakeholder engagement session are currently informing Energy's ongoing work to develop policy options.

Hydrogen Fueling

In January 2023, Energy issued a Request for Expression of Interest (REOI) for parties seeking to design, build, operate, and own hydrogen fueling stations in Alberta, primarily serving the heavy-duty transportation sector. The REOI will provide government with information to guide future steps regarding the conditions that need to be in place for private industry to design, build, operate, and own hydrogen fueling stations. The cross-ministry evaluation of Expressions of Interest is completed. The evaluation will inform next steps, including potential government supports for the mobility sector to adopt hydrogen.[8]

Hydrogen Centre of Excellence

The Hydrogen Centre of Excellence is operated by Alberta Innovates and supports technology and innovation across the hydrogen supply chain. This support includes funding for early-stage projects and front-end engineering and design studies, capital projects through testing capacity, and services capacity, such as through studies and codes and standards. In 2022-23, the Hydrogen Centre of Excellence provided more than $20 million to 18 projects to advance innovations in hydrogen through its first funding competition. The Hydrogen Centre of Excellence also launched its continuous-intake program that provides ongoing funding of $3.8 million, available up to 2026.

Hydrogen Innovation

The Government of Alberta-funded innovation agencies, Alberta Innovates, and Emissions Reductions Alberta, provided more than $30 million in the last year for hydrogen innovation projects. Funding has been provided to conduct pilot projects, demonstrations, and feasibility studies about hydrogen use in heavy-duty trucks, rail transportation, residential and commercial heating, and decarbonization of power generation facilities, among others. Funding for 35 hydrogen projects from these agencies now amounts to more than $92 million.

Natural Gas Investment Attraction

Alberta has distinct competitive advantages in place to lead a clean-energy economy while supporting the global effort to decarbonize, which include significant natural gas resources, a competitive business environment, strong ESG performance, partnerships with Indigenous communities, and an educated and inclusive workforce.

Natural gas investment attraction activities include targeted investor and stakeholder discussions to facilitate investments, collaborations with Global Affairs Canada and the Canadian Trade Commissioner Service on investment inquiries, high-level participation at strategic events, and media engagements to promote Alberta's natural gas investment opportunities.

[8] The mobility sector transports goods and people by methods such as rail, cars, and public transit.

In 2022-23, the Minister and Associate Minister of Energy participated in 26 key natural gas events and four missions to domestic and international markets, focused on natural gas value-chain development, hydrogen investment opportunities, and international and domestic deployment pathways. Highlights include:

- In April 2022, Energy led the Government of Alberta's participation in the inaugural Canadian Hydrogen Convention.
- In May 2022, Associate Minister Nally led a mission to Asia (Tokyo, Japan, and Seoul and Daegu, Korea), anchored by the World Gas Conference held in Daegu, Korea. The mission focused moving toward final investment decisions, global decarbonization and energy security.
- Also in May 2022, Associate Minister Nally spoke at the Canada Gas and LNG Exhibition and Conference (CGLNG) in Vancouver, B.C. Targeted discussions supporting existing and prospective LNG projects, and hydrogen-deployment opportunities in the transportation sector.
- In September 2022, Associate Minister Nally led a mission to Japan to participate at the 2022 Japan LNG Producer-Consumer Conference and 2022 Hydrogen Ministerial Conference. The mission aimed to accelerate potential investment decisions, bolster Alberta's profile, and promote Albertan clean-hydrogen production.
- In February 2023, Minister Guthrie led a mission to Norway and Germany (see page 32). The mission included bilateral meetings focused on strengthening Alberta's gas market access opportunities to Europe and encouraging developments of carbon-intensity measurement for clean hydrogen.

Natural Gas and Hydrogen Market Access

The Hydrogen Roadmap outlines hydrogen exports as one of the five leading markets for hydrogen end-use opportunities. It is more energy efficient and economical to transport hydrogen over long distances to export markets by first converting it to ammonia, which can be converted back to hydrogen at destination or used directly in certain applications (for example, ammonia co-firing in power generation). Ammonia can be shipped by pipelines or by rail to western Canadian ports, from which it can be transported on tankers to Asian markets.

Energy, jointly with Trade, Immigration and Multiculturalism, continues to work closely with the federal government to examine potential government actions that support the movement of ammonia by rail to the western coast of Canada for export to Asian markets. The department is discussing enabling of the ammonia supply chain with governments and industries.

In July 2022, The Government of Alberta committed to pursuing a joint study with the Japanese Organization of Metals and Energy Security (JOGMEC) to evaluate Alberta's potential to export clean ammonia to Japanese markets. The ongoing study offers an opportunity for Alberta to provide detailed data that can help position the province for future investment in ammonia production from Japanese companies, which will have positive economic benefits and create jobs. The study is nearing completion.

Liquified Natural Gas (LNG)

Advancing Liquid Natural Gas (LNG) is a key goal of Alberta's Natural Gas Vision and Strategy, with a target of two to three additional LNG projects by 2030 that use Alberta natural gas as a feedstock. By growing access to global markets, Alberta's natural gas can help meet the rising demand for sustainable energy while creating jobs and billions of dollars in revenue. The global energy system is undergoing immense change as Europe and Asia diversify their energy sources following Russia's invasion of Ukraine and countries turn to cleaner energy sources to lower emissions. Supplying natural gas to replace coal-fired electricity, especially in growing Asian markets, can reduce global emissions by millions of tonnes per year.

In 2022-23, Alberta's profile was increased in targeted international markets through in-market presence, such as through the Minister of Energy's Spring 2023 mission to Norway and Germany to promote Alberta's LNG objectives. Alberta is pursuing collaborative intergovernmental opportunities to advance the Canadian LNG sector. Alberta collaborated with industry, industry associations, governments, crown corporations, and agencies to encourage new routes for Alberta exports, such as through the Port of Churchill. The Government of Alberta is also working with project proponents to evaluate how Alberta's natural gas can gain global access.

Alberta-based natural gas producers are also accessing global markets through creative contracts with a U.S. Gulf Coast project.

Plastic Circular Economy

A circular economy is one in which the full value of a plastic product is used across multiple lifecycles, instead of being used once and discarded into landfills or waterways. A plastics circular economy is one of five pathways identified in Alberta's Natural Gas Vision and Strategy that has significant potential for growth. The goal is to establish Alberta as the western North American centre of excellence for plastics diversion and recycling by 2030. By extending the plastics value chain, Alberta will add jobs, diversify the economy, create wealth, and improve the environment. This will help strengthen Alberta's environmental, social, and governance performance.

Work on advancing a plastics circular economy in Alberta is a collaborative effort, led by Environment and Protected Areas. In 2022-23, Energy supported the following work:

- Energy, along with Environment and Protected Areas, Alberta Innovates, and Prairies Economic Development Canada, commissioned a third-party consultant (Eunomia Research and Consulting LLC) to conduct a study of plastics feedstock in and around Alberta. The study will support the development of a robust plastics supply chain through the identification (e.g., plastic type), quantification and flow of plastic feedstock available for recycling, and quality of plastic feedstock materials, the aim being to increase the volume of recycled material as feedstock for industrial processes.
- Energy continued to advocate for Alberta's position regarding federal plastic waste-management issues to mitigate the risk of federal encroachment and to protect Alberta's interests regarding single-use plastic bans and federal recycled-content requirements. Ongoing work is being done to foster innovation and targeted technical support, encourage intergovernmental collaborations and alignment, and address provincial policy, legislative, and regulatory barriers.

Alberta Petrochemical Incentive Program (APIP)

The Alberta Petrochemicals Incentive Program is a grant-based program created to attract petrochemical investments in Alberta, increase investment, and create jobs. The program application process consists of two stages: Advance Notification (the initial review), and Qualification (final review). Projects that are successful in both review stages enter into a grant agreement with specific operational and reporting requirements for the grant payment. Successful companies must submit an Earned Grant Application to request grant payments. The program's objective is to make Alberta one of the best locations in the world for petrochemical production.

The program has received a total of 19 applications. Currently, Energy has approved 11 advance notifications and is reviewing a qualification application. Three applications have been withdrawn, cancelled, or rejected.

In 2022-23, there was continued interest in the program, and two projects received grant approval:

- Dow Chemicals Canada was approved for a grant worth $32.5 million for its Fort Saskatchewan 12th Furnace Capacity Improvement project. Dow's Fort Saskatchewan Furnace Expansion is a $299-million project that will be an addition to the existing ethane-cracker facility in Fort Saskatchewan, Alberta. The project involves the construction of a new ethane-cracking furnace and debottleneck equipment for a 140,000 metric tonne ethylene expansion. This project created around 400 jobs during construction and four permanent jobs once operational. It is anticipated that this project will contribute $200 million to Alberta's gross domestic product in the first 12 months of being operational, along with a 30-year present-value contribution of almost $4 billion.
- Air Products was approved for a grant worth $161.5 million for its new Hydrogen Production and Liquefaciton Facility. The Air Products Hydrogen Production and Liquefaction Facility is a $1.6 billion project located near Edmonton. It is designed to consume 72,000 gigajoules per day of natural gas to produce 165 million standard cubic feet per day of hydrogen. This project is expected to create more than 2,500 construction jobs and 30 permanent jobs.
- Previous approvals under the program included a grant of $408.3 million for the Inter Pipeline Heartland Petrochemical Complex, a $3.9-billion facility in Strathcona County that converts Alberta propane into polypropylene, a recyclable plastic. This project created approximately 24,000 jobs during construction, 1,376 jobs during operations, and 275 permanent jobs.

Methane Emissions

In April 2023, Alberta announced its aspirations to develop pathways to achieve a 75 to 80 per cent methane reduction by 2030, aligning with the federal government's previously announced (2021) commitment of a 75 per cent reduction in methane emissions by 2030 from 2012 levels for the oil and gas sector. Energy is actively supporting Environment and Protected Areas to ensure Alberta maintains jurisdiction with Alberta-based approaches to methane emissions that are cost-effective and maximize benefits to all Albertans. Energy also continues to work with the Alberta Energy Regulator and industry to investigate opportunities to reduce red tape and streamline data and reporting processes.

Alberta companies continue to show great leadership, employing innovative technologies and industry expertise to reduce methane emissions. Since the start of 2020, the Government of Alberta has made more than $270 million available for methane reduction projects, including $57 million from the Technology Innovation and Emissions Reduction (TIER) fund for programs specific to supporting methane reductions and improved data.

Alberta's second annual progress report for the 2021 reporting year shows that oil and gas methane emissions decreased by about 44 per cent between 2014 and 2021. Based on these estimates, Alberta will likely meet and surpass its 2025 target to reduce methane emissions in the oil and gas sector by 45 per cent from 2014 levels.

1.2 Enhance Alberta's investment climate through measures to improve the province's standing with investors, including:

- enabling a competitive and adaptive electricity system for Albertans to support job creation, attract investment, and support the adoption of low-carbon energy in the province;[9]
- reinforcing Alberta's long-standing commitment to responsible and innovative energy and mineral resource development and communicating the province's energy and mineral industry performance; and
- working with the Ministry of Indigenous Relations, First Nations, Métis Settlements, and other Métis communities and Indigenous organizations to support Indigenous participation and partnerships in the natural-resource and energy economy.

Environmental, Social and Governance (ESG) Performance

ESG criteria are increasingly being used by investors, financial institutions, and talent to screen potential investment opportunities, highlight corporate behavior, and identify material risk traditionally left undisclosed. ESG criteria are non-financial performance measures used to assess the sustainability, societal impact, and risk of a particular investment.

In 2022-23, Energy continued to support the ESG Secretariat to provide draft input into Statistics Canada's Experimental ESG Dashboard website and interface. Energy also continued to develop its ESG–Net-ZERO Tracker tool and database to track the climate-change commitments and ESG reporting practices of all companies that produce oil and gas in Alberta. As of April 2023, Energy has collected ESG information for approximately 90 per cent of all oil and gas producers in Alberta.

Did You Know?

Canada, led by Alberta, demonstrates strong leadership in ESG performance among energy producing nations. In Alberta, 95 per cent of oil sands production is on a pathway to net zero by 2050. As a result of technological innovation, Alberta's oil sands producers have reduced emissions per barrel by 20 per cent over the past decade, additional emissions reductions of 20 to 28 per cent expected by 2035. As a result, the carbon-emissions intensity of crude oil from Alberta's oil sands falls within the range of other global crude oils. This includes several light and heavy crude oils currently imported and refined in the US, particularly when emissions associated with flaring and venting are considered.

Canadian Energy Centre (CEC)

The CEC has a mandate to respond to misinformation about Canadian oil and natural gas; create original content to elevate the general understanding of Canada's energy sector; and centralize and analyze data that targets investors, researchers, and policymakers. It promotes energy literacy and responds quickly and factually to misinformation about Canada's energy industry. A three-member board oversees the CEC's activities and operations, and consists of the Ministers of Energy, Environment and Protected Areas, and Justice.

In the 2022-23 fiscal year, expenditures were $26.06 million. The CEC established a significant global presence outside North America by using targeted digital advertisements in 2022-23. Highlights of the CEC's achievements include:

- Educated local, national, and international audiences about responsible production, distribution, and innovation in Alberta. The U.S. campaign was extended and continued to focus on Canada's role as a

[9] On October 24, 2022, the government announced new ministry structures. As such, the responsibility for legislation governing the administration of electricity and natural gas utilities in Alberta was transferred from the Ministry of Energy to the Ministry of Affordability and Utilities. Relevant reporting may be found in the Ministry of Affordability and Utilities 2022-23 Annual Report.

safe and reliable source of energy that is produced ethically and in accordance with high environmental standards. The campaign attracted four million visitors to its website.

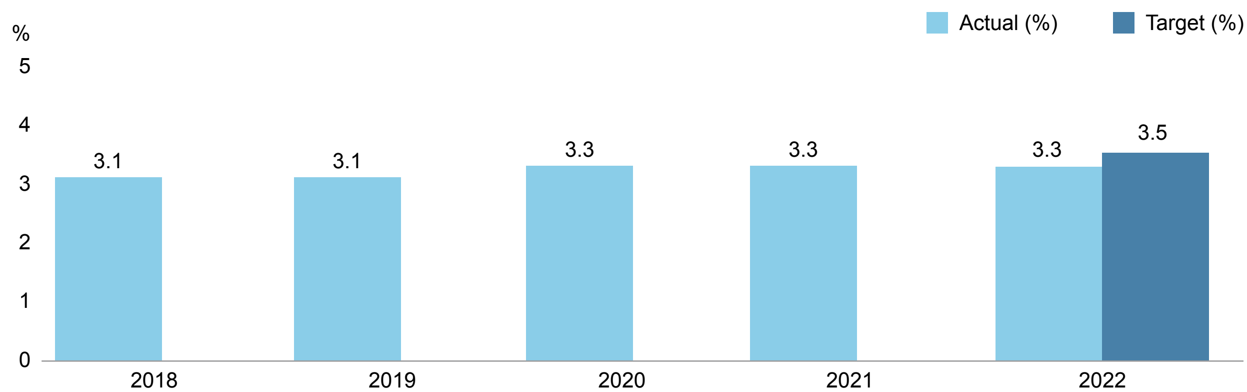
- Launched a campaign in the United Kingdom and several other Western European countries to emphasise Canada and liquefied natural gas as a key part of the long-term solution to the global energy crisis. The campaign achieved over seven million digital impressions.
- Established a significant global presence using targeted digital advertisements during significant energy and climate conference events. Digital advertising targeted leaders and decision makers during the G7 Summit in Germany, the Offshore Northern Seas conference in Norway, the International Energy Summit in the United Kingdom, COP 27 in Egypt, and Climate Week NYC 2022.
- Moved sentiment regarding Canadian energy in a positive direction. Pre- and post-campaign research indicated that support for the Canadian energy sector rose from 47 per cent to 61 per cent among individuals that saw the advertisements. In the U.S. pre- and post-campaign research indicated that support for Canada, as the preferred supplier to meet any shortfalls in oil and natural gas, rose from 65 to 85 per cent among individuals that saw the advertisements.

The CEC reinforces Alberta's long-standing commitment to communicating the province's performance in responsible, ethical, and innovative energy resource development. The CEC operates as a marketing agency, and much of its performance is based on engagement and interaction with the public. Performance targets and metrics are published online in its annual report.

For more information, visit: https://www.canadianenergycentre.ca/annual-reports/

Performance Measure 1.a: Alberta oil sands supply share of global oil consumption.

Target: 3.5 per cent of global oil consumption is supplied by Alberta's oil sands.



Sources: Alberta Energy Regulator; International Energy Agency[10]

Discussion of Results

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

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

The 2022 supply share was virtually unchanged from the share in 2021 and remained at about 3.3 per cent[11]. The supply share has remained relatively static over the past three years and was about 3.3 per cent during the 2020 to 2022 period. Although the 2022 share was below the target of 3.5 per cent, it was within the accepted range of plus or minus 0.2 per cent. The difference between the actual result and the target was primarily driven by the global oil consumption increase, which exceeded the overall bitumen production growth rate in Alberta. The rate of global year over year oil consumption increased by 2.3 per cent, from 97.7 million barrels per day[12] (bpd) in 2021 to 99.9 million bpd in 2022, as oil demand grew in both non-Organization for Economic Cooperation and Development (OECD) regions and OECD regions in nearly equal measure.

Total crude bitumen production in Alberta also increased from 2021 to 2022, from 3.26 million bpd to 3.32 million bpd, an increase of about 1.9 per cent. The production result in 2022 was an annual record, exceeding the previous record that was set in 2021.

The increase in bitumen production from 2021 to 2022 was significantly smaller than the increase from 2020 to 2021, which was driven by the fact that the impacts of COVID-19 have declined since the onset of pandemic in 2020. The bitumen production growth between 2021 and 2022 is more consistent with the long-term trend than either the acute COVID-19 impact of 2019 to 2022, or the immediate recovery from that impact in 2020 to 2021.

[10] For more information, see the Performance Measure and Indicator Methodology section of this report on page 68.

[11] Note: the last actual result for 2021 for the performance measure was retroactively revised from the result that was reported in the 2021-22 Energy Annual Report, due to the revision of the global consumption statistics reported for 2021. The revised result for 2021 (at 3.3 per cent) was included in the subsequently released 2023-26 Business Plan.

[12] The previous 2021-22 Annual Report reported 96.4 million bpd of global oil consumption for 2021. This volume has been retroactively revised up to 97.7 million bpd.

Both mined and in situ production experienced a production increase from 2021 to 2022, although in situ production grew at a faster pace. Year over year growth rates were 2.2 per cent for in situ production and 1.6 per cent for mined production. In situ production increased from 1.66 million bpd in 2021 to 1.70 million bpd in 2022, and mined production increased from 1.59 million bpd in 2021 to 1.62 million bpd in 2022. However, growth in both sectors was lower than the growth in international oil consumption.

The proportion of in situ and mined production in Alberta in 2022 was almost unchanged from the previous year. In 2022, as in the previous year, in situ production and mined production accounted for about 51 per cent and 49 per cent of total bitumen production in the province, respectively.

Outcome Two:

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

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

Key Objectives

2.1 Collaborate with other ministries to maintain and strengthen a balanced, sustainable approach to managing the cumulative effects of resource development, including the ongoing implementation of liability management activities.

Liability Management Framework[13]

The Government of Alberta announced the new Liability Management Framework in July 2020. The framework is the result of a comprehensive multi-year review undertaken by the Government of Alberta. This process included extensive engagement with a wide range of partners, including industry, the financial community, environmental groups, municipalities, Indigenous communities, and landowners. Environment and Protected Areas, Energy, industry, and the Alberta Energy Regulator (AER) have collaborated over the last year to operationalize the elements of the new framework in a phased approach.

- The Holistic Licensee Assessment uses a multifactor approach[14] to assess the capabilities of oil and gas operators to meet their regulatory obligations at each stage of the development life cycle, prior to receiving regulatory approvals. The liability management rating still plays a role in calculating the deemed liability in the oil and gas sector, as it is integrated into several AER directives as well as the Oil and Gas Conservation Rules. The Holistic Licensee Assessment will replace the liability management rating over time. As a first step, it is now used in the Inventory Reduction Program, the Licensee Management Program, license transfers and security collection for transfers. The AER operationalized the Licensee Management Program in 2022, enabling the regulator to provide proactive, practical guidance and support to licensees before they start struggling to manage their regulatory and environmental liabilities.
- The framework's Inventory Reduction Program established mandatory annual closure spending quotas for site cleanup that every licensee must adhere to and incentives for additional supplemental closure spending. This ensures that sites get cleaned up, provides flexibility for licensees to close sites in a cost effective and efficient manner, and drives consistent economic activity in the oil field and environmental services sectors. The AER required industry to spend $422 million on closure activities in 2022 and $700 million for 2023. The industry-wide spending level is set annually and is anticipated to increase by nine per cent every year, the forecasted target being $992 million in 2027.
- The Closure Nomination Program, formerly referred to as the 'opt-in mechanism', provides a way for landowners, land users, and municipal and Indigenous communities to nominate specific inactive sites for cleanup to the regulator. Licensees are required to provide a rationale for keeping the site; otherwise,

[13] More information about the Liability Management Framework and its implementation can be found at https://www.aer.ca/providing-information/by-topic/liability-management.

[14] This multifactor approach includes the Licensee Capability Assessment and factors listed in Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals.

they are required to submit a site-closure plan. The AER has considered sites nominated through the Site Rehabilitation Program, and ones that met the eligible requestor and site criteria have transitioned into the Closure Nomination Program. The AER publicly engaged about the Closure Nomination Program in 2022 and early 2023. Subsequently, in February 2023, the AER released new editions of Directive 088 and the accompanying Manual 023 that added requirements for the Closure Nomination Program. The program entered service in April 2023.

Taking a proactive approach to liability management throughout the life cycle provides more assurance that companies will be able to meet their regulatory obligations, resulting in fewer sites becoming orphaned.[15]

Unpaid Municipal Taxes

To complement the new liability management framework, the Government of Alberta also took new action to address unpaid taxes owed to municipalities. In March 2023, the Government of Alberta issued a ministerial order under the *Responsible Energy Development Act*, which requires the AER to receive evidence that municipal taxes have been paid when approving license transfers or new licenses.

The Government of Alberta conducted the Unpaid Oil and Gas Property Taxes survey in 2022 and found that a cumulative of $220 million in unpaid taxes has been reported by municipalities, most of which will not be recoverable outside insolvency proceedings because they are owed by companies that are no longer operating or the taxes have been written off by municipalities. Approximately $76 million is owed by companies that are still operating and is potentially recoverable through repayment agreements and other tools.

Integrated Resource Management System (IRMS)

The Government of Alberta approaches natural-resource management from an integrated systems approach, through which the cumulative impacts of non-renewable resource development are examined in relation to economic, environmental, and social interests. The Integrated Resource Management System (IRMS), Land-use Framework, and associated planning processes were designed to provide decision-makers with the information they require to make public-policy decisions about natural-resource development, including consideration of impacts on communities and the environment.

Land-use planning is a complex activity that provides opportunities to support Energy's mandate and presents challenges when developing strategies and outcomes that achieve the desired balance between economic prosperity, social well-being, and environmental protection. For example, it provides a forum for the IRMS ministries to engage in complex conversations about trade-offs, collaborate in the design of policy options, and ensure that existing policies are meeting Albertans' expectations. For industry, land-use plans can also provide policy assurance and surety of access–defining, where and under what conditions non-renewable and renewable resource development can take place. Policy assurance also takes the form of providing an opportunity to review, assess, revise, and update historic policy direction that may be needed to achieve today's desired outcomes.

In 2022-23, Energy worked collaboratively with cross-ministry partners, external stakeholders, and rights holders to advance the department's responsible resource development and stewardship objectives.

Sub-Regional Planning

In 2022-23, Energy supported Environment and Protected Areas on work that progressed on six sub-regional plans. The Cold Lake and Bistcho sub-regional plans were approved by Cabinet and published in April

[15] Performance Indicator 2.e, on page 72, tracks the number of wells decommissioned each year.

2022. The legally binding regulatory details for both plans remain in development. The sustained efforts that external stakeholders and rights holders put into engaging with government through the sub-regional task forces and working groups active in 2022-23 reinforced the value of engaging broadly and openly in matters pertaining to integrated resource management.

The Berland and Chinchaga task forces met throughout the year and wrapped up their work in February and March 2023, respectively. Energy worked alongside IRMS partners to coordinate external and internal working groups for the Upper Smoky and Wandering River sub-regions. Both plans were originally targeted for completion in 2022 but are now expected in 2023.

For a map of the location of these regions, please visit www.alberta.ca/assets/documents/aep-caribou-sub-regions-alberta-map.pdf.

On December 8, 2022, Energy announced it would be offering tenure extensions for Crown mineral agreements in caribou ranges. Upon application, extensions would be granted to qualifying Crown agreements in caribou ranges until the agreement expiry falls on its term date in 2026. This change is not expected to increase activity in caribou ranges since it provides current leaseholders more time to plan and complete their work. Granting tenure extensions in caribou ranges will increase short- and mid-term certainty, as the 11 sub-regional plans are not expected to be in place for all caribou ranges until at least 2025.

Regional Planning

The Lower Athabasca Regional Plan (LARP) 10-year review commenced in August 2022. This work is led by the Land Use Secretariat, within the Ministry of Environment and Protected Areas, and is supported by Energy as an active participant under the IRMS. The purpose of the review is to elicit feedback from multiple stakeholders, Indigenous communities, and organizations to help government understand the ongoing relevancy and effectiveness of the LARP. The results of the review are not expected until later in 2023.

Orphan Wells

The Orphan Well Association (OWA) has delegated regulatory authority to clean-up wells or sites that do not have a viable or responsible owner. Industry remains liable for these orphan wells. Obligations related to the full closure of oil and gas sites are the responsibility of the company (the licensee) licensed by the AER to conduct activity on the site. If a licensee goes bankrupt, and there are no related parties to conduct closure activities on their sites, the AER will declare the site an orphan and transfer the responsibility of the site to the OWA. The OWA is funded by industry and was established to address closure requirements for sites held by bankrupt licensees.

Over the last several years, the OWA decommissioned more wells than it received. In 2021, the OWA began decommissioning work

Orphan Well Loan Program

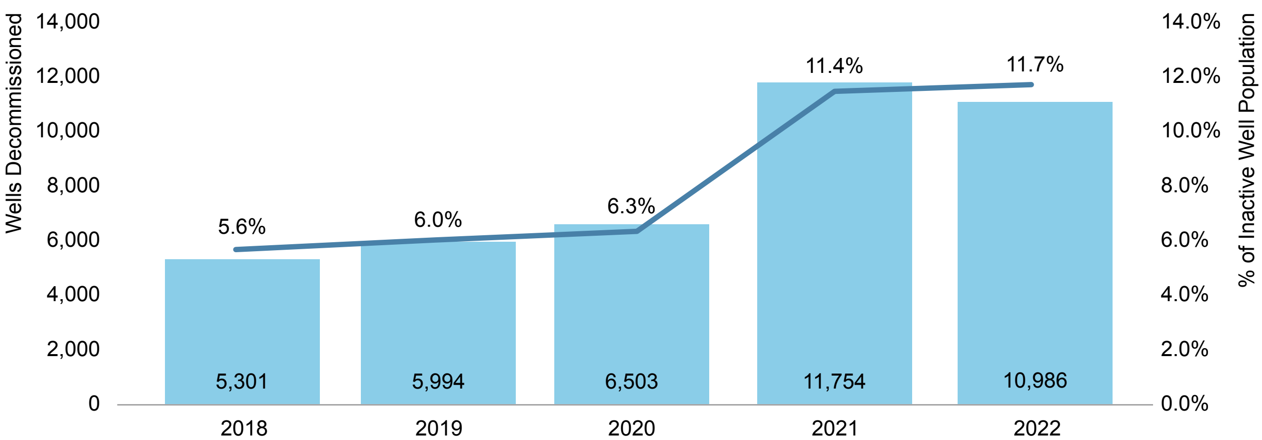
In 2017, the Alberta government provided the OWA with an interest-free loan for $235 million (the Orphan Well Loan Program) to accelerate the reclamation of oil and gas well sites that no longer have responsible owners. In April 2020, an additional $100-million loan facility was added to the loan agreement. The $100 million was advanced to the OWA on March 31, 2021, for a total of $335 million under the Orphan Well Loan Program. The focus of the additional loan facility was for closure work on lands receiving compensation under section 36 of the *Surface Rights Act*. The money received from industry through the annual Orphan Fund Levy is used by the OWA to repay the loan extended during the OWLP. As of April 2023, the OWA has repaid the Government of Alberta about $121.8 million of the $335 million advanced to accelerate reclamation of orphan well sites.

on the Mazeppa Gas Plant, the first project undertaken through the Alberta Energy Regulator (AER)'s Large Facility Program. In 2022, the OWA completed the gas plant decommissioning.[16]

Annual Wells Decommissioned: Performance Indicator 2.e

Decommissioning is part of the closure process and involves the company removing surface equipment and sealing the well to prevent the well from affecting the environment. This indicator demonstrates the degree to which industry is moving inactive well inventory through the life cycle toward closure. Increases in insolvent companies and low commodity prices during the COVID-19 pandemic resulted in an unprecedented number of wells and facilities being sent to the OWA.

Annual Wells Decommissioned



Source: Alberta Energy Regulator[17]

In 2022, 10,986 wells were decommissioned in Alberta. This is a slight decrease from 2021 levels, but both 2021 and 2022 are well above the levels of the prior three years. The notable increase in well decommissioning in 2021 is related to a variety of efforts, including the organized and staged implementation of the Liability Management Framework, Directive 088, the continuation of the Area-Based Closure initiative, and the Site Rehabilitation Program, in addition to the increased closure activity underway by the OWA. An increase in year over year numbers is a positive signal that operators are addressing their inactive well inventory, which prevents the well from affecting the surrounding environment.

[16] For more information, please visit https://www.orphanwell.ca/about/annual-reports/.

[17] For more information, see the Performance Measure and Indicator Methodology section of this report on page 68.

2.2 Reduce red tape, and optimize regulation and oversight of:

- Alberta's energy and mineral resource sector to utilize and develop resource potential; and
- Alberta's utilities to ensure the public interest of Alberta is protected through legislation to ensure safe, reliable, efficient, and environmentally responsible development and operation of the electric and natural gas system.[18]

Alberta Energy Regulator (AER)

The AER is responsible for regulating the life cycles of oil, oil sands, natural gas, and coal projects in a manner that protects public safety and the environment. The energy industry fully funds these activities, and in 2022-23, operating costs totaled $207 million. Under the direction of the Government of Alberta, the AER's mandate is expanding to include emerging energy and mineral resource development. In 2022-23, the Government of Alberta provided grants to support costs of $17 million towards the development of these new sectors and associated regulatory frameworks.

Industry Performance Program

The Alberta Energy Regulator's (AER) Industry Performance Program monitors, measures, evaluates, and reports the energy industry's performance in Alberta. Under the program, the AER publishes performance reports about pipeline incidents, water use, and methane emissions to provide Albertans with information regarding energy-development activities and how the AER works to protect public safety and the environment.

Pipeline performance report[19]

The pipeline performance report provides Albertans with information about the inventory and substances being transported by pipelines in the province, the number of pipeline incidents, and the type of failures and causes of pipeline incidents. The AER evaluates all pipeline failures to understand the causes and to assess compliance with rules. The AER uses what it learns to educate companies, either during pipeline inspections or, for example, by publishing bulletins.

In 2021, there were about 41 per cent fewer incidents than in 2012, even though the total pipeline kilometres grew by 9 per cent in the same period. This translates into an incident rate of 0.78 per 1,000 kilometres of pipeline compared with 1.44 per 1,000 kilometers in 2012.

Water use performance report[20]

The AER's water use performance report highlights how water is allocated and used to produce oil, gas, and oil sands resources. In 2021, companies used much less non-saline water (lake or river water, groundwater, or surface runoff water) than was allocated to them. Only 13 per cent of non-saline water allocated to all industries in the province was allocated for oil and gas development, and the industry used only 19 per cent of its allocation, down from 26 per cent in 2020. Of the water the oil and gas industry used, 17 per cent was non-saline, and 1 per cent was alternative make-up water (saline groundwater, wastewater, or water recycled from hydraulic fracturing operations). The remaining 82 per cent of the water used for energy development was recycled. Non-saline water-use intensity across the energy industry has decreased by 14 per cent since 2017.

[18] On October 24, 2022, the government announced new ministry structures. As such the responsibility for legislation governing the administration of electricity and natural gas utilities in Alberta was transferred from the Ministry of Energy to the Ministry of Affordability and Utilities. Relevant reporting may be found in the Ministry of Affordability and Utilities 2022-23 Annual Report.

[19] The 2022 release of the report can be viewed at https://www.aer.ca/protecting-what-matters/holding-industryaccountable/industry-performance/pipeline-performance.

[20] The 2022 release of the report can be viewed at https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industry-performance/water-use-performance.

Methane performance report[21]

The AER's latest methane performance report shows that methane emissions from oil and gas operations are estimate to have reduced by approximately 44 per cent between 2014 and 2021. The AER's latest methane performance report was updated in April, 2023.

Regulatory Compliance: Performance Indicator 2.c

The AER tracks the percentage of inspections that did not result in enforcement actions, and the percentage of inspections in compliance with regulatory requirements, reflecting the AER's ability to achieve its mandate through inspection (prevention) activities. Inspections allow field inspectors to determine if regulatory requirements have been met and provide an opportunity to work directly with companies to bring them back into compliance. Inspections that result in noncompliance are triaged and assessed based on the AER's Integrated Compliance Assurance Framework to determine the best course of action to the correct the noncompliance.

	2018-19	2019-20	2020-21	2021-22	2022-23
Compliant Inspections: Percentage of inspections in compliance with regulatory requirements	76	78	79	75	73

Source: Alberta Energy Regulator[22]

In 2022-23, the AER conducted 8,128 field-based inspections and 5,928 resulted in a finding of compliance. In 2021-22, 7,825 field-based inspections were conducted and 5,891 resulted in a finding of compliance.

While more inspections were completed in 2022-23, compliant inspections remained uniform with last years' totals, and conversely, sites with non-compliances saw a slight increase this year. 2,200 non-compliant inspections occurred in 2022-23 whereas 1,984 were managed in 2021-22. Non-compliances can range in severity from things such as failing to submit a required monitoring report to releasing a toxic substance into the environment. This increase is likely the result of a combination of factors, including increased industry activity as more pipelines and facilities are being reactivated, Directive 60 emissions requirements ensuring enhanced scrutiny of high-volume venting sites, and the AER's field inspectors continuing to leverage organizational data to identify common non-compliances, resulting in more items being checked during inspections.

Pipeline Safety: Performance Indicator 2.d

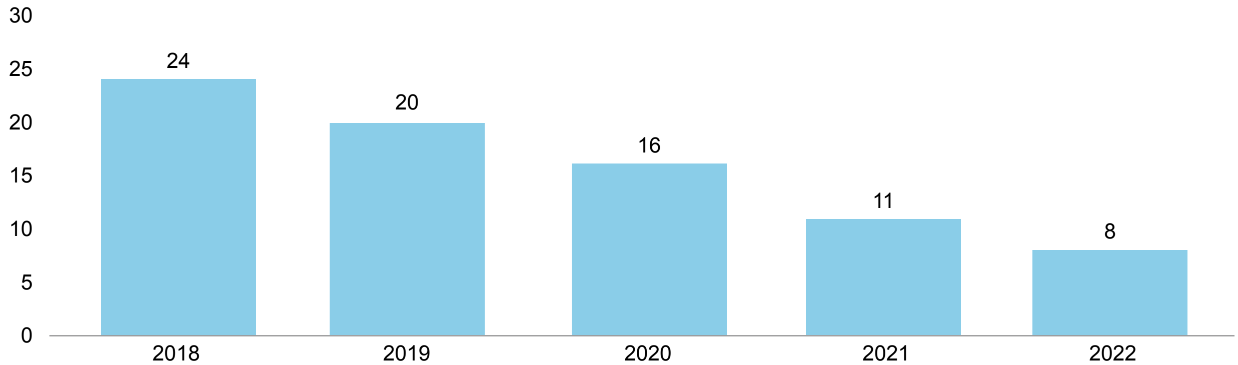
The AER conducts construction and operational inspections, to ensure operators comply with pipeline regulations to safely operate and prevent incidents. To prevent pipeline incidents from occurring, the AER inspections focus on preventative pipeline maintenance programs, leak detection, hydrotechnical and geotechnical programs and inactive pipelines. When a pipeline incident does occur, all incidents are reviewed by an inspector to understand the cause and prevent future incidents of a similar manner.

Where appropriate, the AER also helps educate licensees on pipeline integrity issues and how to address them. If the AER identifies that a pipeline is causing or has the potential to cause unacceptable impacts, it can order an immediate suspension of the pipeline until the problems are corrected.

[21] The 2022 release of the report can be viewed at: https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industry-performance/methane-performance. The report will be updated in spring 2023 with updated data.

[22] For more information, see the Performance Measure and Indicator Methodology section of this report on page 68.

Number of High Consequence Pipeline Incidents



Source: Alberta Energy Regulator[23]

Note: Reviews of past incidents and more accurate information coming available over time has resulted in changes to previously reported numbers and are subject to change as more information is gathered.

Compared with 2021, 2022 saw a decrease of high consequence pipeline incidents from 11 to 8. Some factors that influenced these results in 2022 include the following:

- industry developing and adopting better pipeline practices;
- the AER continuing to improve pipeline requirements, inspections, and placing a greater focus on educating industry about pipeline safety;
- the AER continuing to educate industry and ensure compliance through leak detection programs to prevent large volume spills; and
- the AER issuing Bulletin 2021-36 to remind licensees to consider stress corrosion cracking as part of their integrity management programs after an increase in incidents where this was the cause.

Dam Safety

Dams are owned by operators in oil sands mining, in situ oil sands, coal mining, and oil and gas operations. Under the Water Ministerial Regulation and its associated Dam and Canal Safety Directive, the Alberta Energy Regulator (AER) regulates 243 dams across the province, including 129 tailings dams, the majority of which are in the oil sands mining sector dams operated by energy companies.

Did You Know?

The AER dam safety map provides the public information on AER-regulated dams and is available at www.aer.ca

In 2022, the AER released the AER Dam Safety Program: 2021 Report:[24]

- The AER completed 71 inspections of dams and more than 250 technical reviews of dam safety submissions.
- No critical safety deficiencies were identified during inspections or reported to the AER.
- 30 notices of noncompliance were issued, and all have been adequately addressed by the dam owners, and either compliance has been achieved or is in progress.

[23] For more information, see the Performance Measure and Indicator Methodology section of this report on page 68.

[24] The report is available at: https://www.aer.ca/providing-information/by-topic/dams.

- The AER responded to one dam safety-related incident[25] where the dam had insufficient conveyance or storage capacity and was overtopped; this incident was a critical safety deficiency is being investigated by the AER.[26]

Fluid Tailings Management

The Alberta Energy Regulator (AER) regulates tailings in Alberta's mineable oil sands in accordance with all requirements set under the Government of Alberta's Tailings Management Framework for the Mineable Athabasca Oil Sands (TMF) and the AER's Directive 085: Fluid Tailings Management for Oil Sands Mining Projects (Directive 085). The TMF requires companies to progressively treat their tailings with a technology approved by the AER, so that they are ready to reclaim within 10 years after mining has stopped. The AER has approved tailings management plans for each oil sands mine, which list the actions companies will take over the next several decades to meet this objective in the TMF.

Under Directive 085, the AER reports annually on the amount of tailings produced at each oil sands mine and the technologies that companies are using to treat their tailings. The AER's latest report, titled 2021 State of Fluid Tailings Management for Mineable Oil Sands[27] shows:

- operators continue to operate within all limits and triggers set by the AER within their approvals;
- from 2014 to 2017, the total volume of water in tailings ponds decreased, then increased between 2018 and 2020, before a decrease in 2021;
- from 2014 to 2019, bitumen production increased, as did the number of operating mines, followed by a decrease in production in 2020 during the COVID-19 and the associated drop in global oil demand; and
- bitumen production increased to its highest level yet in 2021.

An Environmental Protection Order (EPO) was issued February 6, 2023, by the Alberta Energy Regulator to Imperial Oil in response to two separate waste water release incidents at the Kearl Oil Sands Project. Kearl is an Imperial Oil owned and operated oil sands operation.[28]

Seismicity

The Alberta Energy Regulator (AER), through the Alberta Geological Survey (AGS) uses a network of over 50 monitoring stations across the province to measure and research seismic activity across Alberta. This information is used by AGS to form an accurate picture of earthquake locations, magnitudes and to determine the cause of these events, which are publicly reported on the Alberta Earthquake Dashboard. Alberta experiences natural and induced seismic events, most of which are not felt due to low intensity and ground conditions. To date, the AER is not aware of any damage that has been caused by seismic events in Alberta.

In Alberta, human activities that can cause induced earthquakes include:

- the extraction of fluids,
- geothermal operations,
- wastewater disposal,
- the impoundment of dams,

[25] A "dam safety incident" is defined by the Dam and Canal Safety Directive as an operation or action at, or in connection with, a dam that has the potential to create a hazardous condition or to be or become a hazard to factors at risk.

[26] Please refer to the AER compliance dashboard and search the reference number "2022-047" for further details, which is available at: https://www1.aer.ca/compliancedashboard/index.html.

[27] https://static.aer.ca/prd/documents/reports/State-Fluid-Tailings-Management-Mineable-OilSands.pdf.

[28] Reporting on the two incidents at the Kearl Oil Sands Project can be found in the Environment and Protected Areas 2022-23 Annual Report.

- subsurface storage using Carbon Capture Utilization and Storage technology (CCUS), and
- hydraulic fracturing.

In areas where earthquakes have been induced from energy development in the past, the AER has issued orders to operators to limit the hazard of induced seismic activity. In addition, in areas of the province where the likelihood of an induced earthquake is higher, the AER has developed monitoring and reporting requirements that companies conducting hydraulic fracturing must follow. If companies fail to meet AER requirements, compliance and enforcement tools are available to bring operators back into compliance.

In 2022-23, the AER and AGS:

- issued one order to operators to limit public and environmental impacts when earthquakes are confirmed to be induced by energy development.[29]
- produced annual seismic hazard analysis maps which provide the public with additional information on ground shaking from earthquakes in the province in the previous year and a forecast of potential ground shaking in the upcoming year.[30]
- added two additional seismic stations to the AGS network in 2022, and continued to update webpages on https://www.aer.ca and https://ags.aer.ca to provide the public with additional information on induced seismicity.[31]

[29] To view the list of the AER's Subsurface Orders, please visit: https://www.aer.ca/regulating-development/compliance/orders/subsurface-orders.

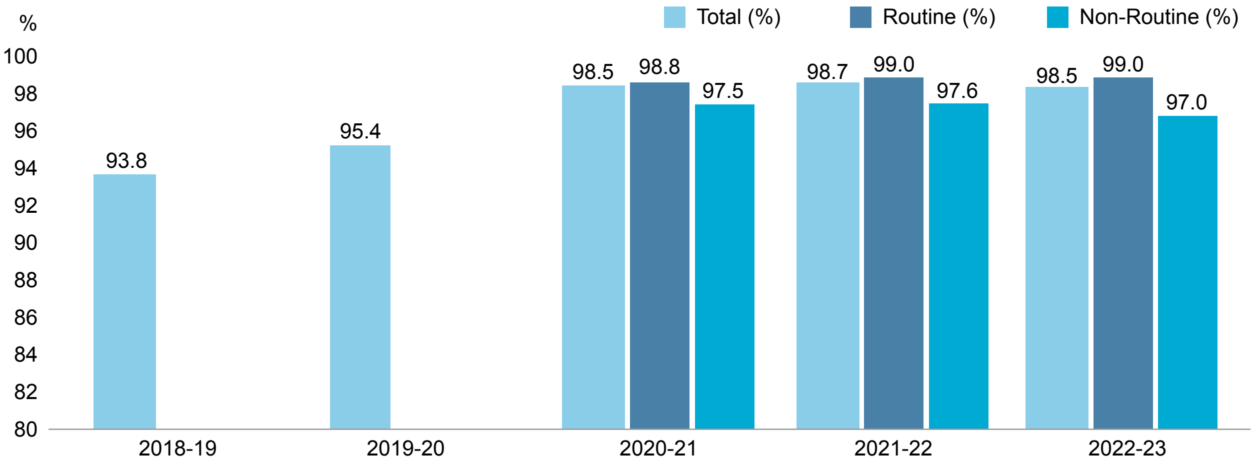
[30] The maps are available at: https://ags.aer.ca/research-initiatives/mapping-seismic-hazard.

[31] For more information, please visit: https://www.aer.ca/providing-information/by-topic/seismic-activity.

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

Target: The target for applications meeting turnaround targets for 2022-23 is 99 per cent for routine applications and 95 per cent for non-routine applications.

Percentage of Alberta Energy Regulator applications that met the turnaround targets



Sources: Alberta Energy Regulator[32]

Discussion of Results

This measure indicates the Alberta Energy Regulator's efficiency in application processing, drives internal performance, and provides certainty and transparency to the public related to AER's turnaround targets. Overall, in 2022-23, 98.5 per cent of AER applications met turnaround targets.

The total number of applications received by the AER in 2022-23 was 36,552. This was comparable to the 37,357 applications received in 2021-22. In 2022-23, the AER met processing targets for 99.0 per cent of routine applications. The AER also met the processing targets for 97.0 per cent of the non-routine, which are higher-risk and more-complex applications, and exceeded target of 95.0 per cent. Of the 36,464 applications processed in 2022-23, there were 28,094 routine applications and 8,370 non-routine applications.

This performance can be attributed to ongoing implementation of the AER's Integrated Decision Approach, and improvements to AER systems to automate low risk application types allowing AER staff to focus on applications that pose higher risk. These initiatives will contribute to continued improvement in the turnaround targets for routine and non-routine applications.

Application turn-around targets for each application process can be found on the AER's website: https://www.aer.ca/regulating-development/project-application/application-processes.

[32] For more information, see the Performance Measure and Indicator Methodology section of this report on page 68.

Energy Highlights Table

		2021-22	2022-23
Bitumen	Revenue	$11.61 billion	$16.88 billion
	Bitumen wells drilled (1)	1,866 (2021)	3,580 (2022)
	Total bitumen production in barrels per day (bpd)	3.26 million bpd (2021)	3.32 million bpd (2022)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	3.07 million bpd (2021)	3.12 million bpd (2022)
Conventional Crude Oil	Revenue	$1.95 billion	$3.97 billion
	Average price for West Texas Intermediate (WTI)	US$77.03/bbl	US$89.69/bbl
	Conventional crude oil production	0.44 million bpd (2021)	0.49 million bpd (2022)
	Pentanes and condensate production	0.34 million bpd (2021)	0.37 million bpd (2022)
	Crude oil wells drilled (1)	2,519 (2021)	3,653 (2022)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates)	3.85 million bpd (2021)	3.98 million bpd (2022)
	Removals from Alberta	3.74 million bpd (2021)	3.86 million bpd (2022)
	Per cent of total crude oil and equivalent disposition	88% (2021)	87% (2022)
Natural Gas and By-Products	Revenue	$2.23 billion	$3.60 billion
	Average Alberta Gas Reference Price	3.48/GJ	4.63/GJ
	Number of conventional natural gas wells drilled (1)	802 (2021)	956 (2022)
	Total marketable natural gas production including coalbed methane	3.52 Tcf (2021)	3.76 Tcf (2022)
	Coalbed methane production	0.16 Tcf (2021)	0.16 Tcf (2022)
	Total natural gas deliveries	5.25 Tcf (2021)	5.51 Tcf (2022)
	* To the United States	33%	32%
	* Within Alberta	39%	39%
	* To rest of Canada	27%	29%
	Helium Revenue	$146,256	$199,893[33]
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases (6)	$228 million	$465 million
	Revenue from rentals and fees	$153 million	$189 million
	Direct sales of Crown leases	$2 million	$13 million
	Average price per hectare (ha) paid at petroleum and natural gas rights sales	$328.35	$579.50
	Petroleum and natural gas hectares sold at auction	495,004.82 ha	658,494.09 ha
	Average price per hectare paid for oil sands mineral rights	$1,075.34	$700.86
	Oil sands hectares sold at auction	59,256.78 ha	100,585 ha

[33] Note: Helium revenue results for 2022-23 include April 2022 to January 2023. Results for the full fiscal year will be available in July.

		2021-22	2022-23
Freehold Mineral Tax	Revenue	$107 million	$161 million
Wells and Licences	Well Licences issued (3)	6,523 (2021)	7,639 (2022)
	Industry drilling (4)	5,709 (2021)	8,863 (2022)
Coal	Revenue	$10 million	$146 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.1 billion tonnes
	Raw coal production	14.4 million tonnes (2021)	20.1 million tonnes (2022)
	Total marketable coal deliveries	11.1 million tonnes (2021)	13.4 million tonnes (2022)
	Percentage of total coal deliveries exported out of province	59.5% (2021)	65.6% (2022)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	$591,883	$494,896
	Hectares of mineral permits issued to exploration companies (LAMAS, MIM Permits and New Application Issued)	3.2 million ha	2.4 million ha
Upstream Energy Sector Employment		139 thousand (2021)	138 thousand (2022)
Upstream Energy Sector Investment (5)		$19.0 billion (2021)	Estimated $24.6 billion (2022)

Notes to table:

1. Data on wells drilled include both development and exploratory wells.
2. Totals may not align due to rounding.
3. Results have been retroactively adjusted.
4. In addition to development and exploratory bitumen, crude oil, and natural gas wells drilled, total industry drilling includes oil sands evaluation wells, and other wells, such as water, waste brine, and miscellaneous wells. Coalbed methane wells are also included, where applicable.
5. Investment data results for 2021 have been retroactively adjusted to reflect the updates that took place since the publication of the 2021-22 Annual Report.
6. Results include direct sales of Crown leases.

In some cases, totals may not add up due to rounding.

Royalty Programs

The Government of Alberta owns 81 per cent of oil and gas resources in Alberta and collects royalties from companies when an oil or gas well, oil sands project, or mineral project is in production. On behalf of Albertans, the ministry reviews and maintains a competitive and effective royalty regime that attracts industry investment, which provides jobs, business opportunities, tax and royalty revenue, and numerous other benefits to the provincial economy. This work supports outcome one from the Ministry of Energy's 2022-23 Business Plan: Albertans benefit from investment in responsible energy and mineral development and access to global markets.

Royalty programs exist for a number of reasons, including:

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

There are programs under the two royalty frameworks in Alberta: the Modernized Royalty Framework and the Alberta Royalty Framework.

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

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

- The total royalty revenue for each royalty program is sourced from various royalty reporting systems for crude oil, natural gas and oil sands. Amendments by industry can be filed for up to three years from the production year. In addition, the total royalty revenue for each royalty program reflects the revenue from wells that are qualified for the respective royalty programs in a given year. It does not represent the net revenue from those wells as the royalty revenue on natural gas and gas products can be further reduced by eligible deductions, such as the Gas Cost Allowance.
- The royalty programs under the Alberta Royalty Framework are reported on a calendar year basis and reflect the amendments filed by industry each year.
- The royalty programs under the Modernized Royalty Framework are reported on a fiscal year basis to align with government reporting as a whole and reflect amendments filed by industry each year.
- In June 2019, government introduced the *Royalty Guarantee Act* to increase investor certainty that the royalty structure in place when a well is drilled will remain in place for at least 10 years.

Modernized Royalty Framework Royalty Programs

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

Enhanced Hydrocarbon Recovery Program

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

The objectives of the Enhanced Hydrocarbon Recovery Program are to:

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

During the 2021-22 fiscal year, the Enhanced Hydrocarbon Recovery Program received nine applications in comparison to three applications in the 2020-21 fiscal year. The increase is likely due to the significant increase in commodity prices for the fiscal year as we emerged from COVID-19. The overall trend for program uptake has been relatively steady since the first year of the program inception. Since the program's inception in 2017, 44 applications were received from 26 companies, of which 19 were approved.

Enhanced recovery techniques are typically used in a phased approach in legacy fields where primary production has already occurred.

- Two applications for the secondary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by water flooding, gas cycling, gas flooding, polymer flooding or similar techniques, were approved during the 2021-22 fiscal year.
- Zero applications for the tertiary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or similar techniques, were approved during the 2021-22 fiscal year.

	2017-18	2018-19	2019-20	2020-21	2021-22	Total
Number of Applications Received	11	12	9	3	9	44
Number of Different Companies Submitting Applications[34]	8	11	7	3	8	26
Number of Applications Approved	0	4	7	6	2	19
Number of Applications Denied	0	11	4	1	3	19
Number of Applications Withdrawn	0	1	0	0	0	1
Applications to be Processed at the end of 2021-22 Fiscal Year						1

Note: Application approval/denial/withdrawal are counted in the year a decision is made, not in the year of receipt of application.

The active enhanced recovery schemes in the program generated a total Crown production of 187,208 cubic metres of oil, and 169,022,500 cubic metres of gas in 2021-22. In comparison, active enhanced recovery schemes generated a total Crown production of 128,918 cubic meters of oil, and 181,071,700 cubic meters of gas in 2020-21, a year over year increase of 45.2 per cent for oil and a decrease of 6.7 per cent for gas. The increase in oil can be attributed to developed wells in the approved schemes starting hydrocarbon production, and 17 out of 19 approved recovery schemes are in oil pools.

[34] Note: Annual numbers of companies do not add up to the total as some companies submitted applications in more than one year.

Total Crown royalty volumes from the approved enhanced recovery schemes totaled 10,014 cubic metres of oil, 4,252 cubic metres of natural gas liquids and 21,327,300 cubic metres of gas, which translates to about $7.0 million in total royalty revenue in 2021-22, an increase of 124 per cent from 2020-21.

	2018-19	2019-20	2020-21	2021-22
Total Crown Royalty Volumes–Oil (m^3)	2,698	5,195	6,448	10,014
Total Crown Royalty Volumes–NGL (m^3)	1,395*	2,347	2,967	4,252
Total Crown Royalty Volumes–Gas (10^3m^3)	12,407*	15,275	14,570	21,327
Total Crown Royalty Revenue ($)	1,820,232*	3,114,633	3,112,904	6,963,606

*Previous year's data has been restated to show the Crown Royalty Volumes after the Royalty Rate is applied to align with control record methodology for determining oil data.

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

Emerging Resources Program

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

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

During the 2021-22 fiscal year, the Emerging Resources Program received one application. Since the program was launched, 24 applications have been received from 15 companies. Seven applications were approved, 15 applications were denied, one was withdrawn, and one was under review at the end of the 2021-22 fiscal year.

	2017-18	2018-19	2019-20	2020-21	2021-22	Total
Number of Applications Received	7	6	4	2	1	24
Number of Different Companies Submitting Applications[35]	6	5	4	1	1	15
Number of Applications Approved	1	3	3	0	0	7
Number of Applications Denied	4	1	5	4	1	15
Number of Applications Withdrawn	0	1	0	0	0	1
Applications to be Processed at the end of 2021-22 Fiscal Year						1

The cumulative number of potential new project wells participating in the program in 2021-22 fiscal year was 4,080. The number of new project wells did not increase in 2021-22 as no new applications were approved.

	2017-18	2018-19	2019-20	2020-21	2021-22
Number of New Project Wells	766*	2,190*	1,124	0	0
Cumulative Number of Project Wells	766*	2,956*	4,080	4,080	4,080

*Previous year's data has been amended to match control record methodology.

[35] Note: Annual numbers of companies do not add up to the total as some companies submitted applications in more than one year.

Approved projects in the program generated a total Crown production of 308,491 cubic metres of oil, 12,374 cubic metres of condensate, and 2,022,063,400 cubic metres of gas in 2021-22, which are similar to production levels in 2020-21, driven by new project wells have started to produce.

Total Crown royalty volumes from Emerging Resources Program projects totaled 15,425 cubic metres of oil, 81,606 cubic metres of natural gas liquids, 619 cubic metres of condensate, and 101,103,200 cubic metres of gas. This translates to about $62.3 million in total royalty revenue in 2021-22 from approved Emerging Resource Program projects, an 84 per cent increase from 2020-21 – this increase can be attributed to a ramp up of production as the pandemic eased. This royalty revenue to the Crown may not have been generated without the program incentives.

	2018-19	2019-20	2020-21	2021-22
Total Crown Royalty Volumes–Oil (m^3)	7,387	7,246	15,289	15,425
Total Crown Royalty Volumes–NGL (m^3)	9,706*	37,126	82,577	81,606
Total Crown Royalty Volumes–Condensate (m^3)	1,888*	1,242	1,109	619
Total Crown Royalty Volumes–Gas (10^3m^3)	10,499*	34,120	83,788	101,103
Total Crown Royalty Revenue ($)	7,441,782*	17,068,405	33,911,792	62,286,027

*Previous year's data has been restated to show the Crown Royalty Volumes after the Royalty Rate is applied to align the methodology for determining oil data.

Alberta Royalty Framework's Royalty Programs

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

Natural Gas Deep Drilling Program (NGDDP)

The NGDDP made progress towards achieving its intended outcomes of encouraging new exploration and developing production by providing a royalty adjustment to wells with a vertical depth greater than 2,000 metres.

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

The total residue gas[36] production from eligible wells decreased by 62 per cent and liquids production decreased by 59 per cent from 2020 to 2021 due to the termination of program enrollment.

	2017	2018	2019	2020	2021
Total gas production from eligible wells	Residue Gas: 33,746,930 Liquids: 13,274,152	Residue Gas: 22,850,190 Liquids: 8,084,252	Residue Gas: 13,482,771 Liquids: 4,523,810	Residue Gas: 6,578,175 Liquids: 2,254,175	Residue Gas: 2,530,238 Liquids: 916,120
Total Royalty from NGDDP gas wells	$307 million	$176 million	$86 million	$43 million	$29 million

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

[36] Residue gas is the gas mixture left after separation and processing of natural gas liquids that are ready for delivery to the pipeline.

In 2021, gas wells in the program contributed about $29 million in total royalty revenues. The total royalty revenue for the NGDDP has decreased by 33 per cent from the 2020 result. The decline in royalty revenue is consistent with the decline in production under the program. The decline in royalty revenue is mainly due to well production decline, and more wells reaching the NGDDP cap by dollar amount or by the sixty-calendar month cap. An increase in West Texas Intermediate (WTI) oil prices occurred from around US$39/bbl in 2020 to around US$68/bbl in 2021 could not offset the production declines leading to this decrease in royalty revenues.

The NGDDP has not accepted new wells into the program since December 31, 2016, and officially ended on December 31, 2021.

The Emerging Resources and Technologies Initiative

Introduced in 2010, the purpose of the Emerging Resources and Technologies Initiative (ER&T) was to stimulate investment and encourage development of Alberta's unconventional resources through the deployment of new technologies. The initiative supported new exploration, development and production from Alberta's emerging resources in horizontal oil, shale gas, horizontal gas and coalbed methane. The ER&T was implemented to increase investors' ability to recover upfront investments by extending the maximum five per cent New Well Royalty Rate to acknowledge the higher costs and risks in the following four situations: horizontal oil, horizontal gas, shale gas and coalbed methane.

- **Coalbed Methane:** The trend for coalbed methane production in the province is consistently downwards with no production in 2021, The economics of coalbed methane wells continue to be challenging compared to other gas wells. Despite relatively low drilling costs, the supply cost for coalbed methane wells are among the highest. Coalbed methane wells produce mainly dry gas and have very low initial production rates. In addition, coalbed methane wells are typically drilled on a single-well basis and do not benefit from economies of scale associated with drilling multiple wells at one location. This is commonly used in tight and shale formations.
- **Horizontal Gas:** Gas production under the horizontal gas new wells decreased to 6,038 thousand cubic meters in 2021 from 40,652 thousand cubic meters in 2020. Liquids production also saw a decrease to 3,116 cubic meters in 2021 from 29,947 cubic meters in 2020. This is due to termination of the program, as no new wells that spud from 2017 onwards are eligible for the program and production from existing wells decline as they mature. In addition, the pool of the ER&T wells has been shrinking as some of the remaining wells in the pool reach their production or volume cap, which also leads to production decreases.
- **Horizontal Oil:** Horizontal oil wells showed decreases of 34.21 per cent in oil production and 78.04 per cent in solution gas[37] production in 2021 respectively from 2020. Horizontal oil production decreased to 31,941 cubic metres in 2021 from 48,553 thousand cubic meters in 2020. There was no coalbed methane production in 2021 compared to 262 thousand cubic meter in 2020. These decreases are due to termination of the program and high decline rate of the existing well production.
- **Shale Gas:** Production from shale gas wells include shale gas, liquids, oil and solution gas. Production from shale gas wells has decreased since no new wells qualified for the program in 2017 to onwords. In 2021, there were no shale gas, oil or solution gas production from shale gas newly qualified wells. Liquid production from Shale gas decreased to 602 cubic meters in 2021 from 3495 in 2020. These decreases are due to termination of the program and high decline rate of the existing well production.

[37] Solution gas is the gas that is separated from crude oil or crude bitumen after recovery from a well event.

The total royalty revenue for ER&T in 2021 was approximately $1.09 million compared to the 2020 total royalty revenue of $4.23 million. Total revenue generated by wells in the program has decreased by 74.1 per cent compared to 2020. Most of the wells that participated in ER&T continue to produce and generate additional royalty revenue and other economic benefits for the Crown after they exited the program.

The ER&T has not accepted new wells into the program since December 31, 2016, and officially ended on December 31, 2021. The policy intent of the program continues to be relevant and has been built into the Modernized Royalty Framework through the drilling and completion cost allowance (C*) and also the new Emerging Resources Program. The C* is a proxy for the upfront cost of a well and provides a lower upfront royalty rate until the C* has been recovered through production.

Incremental Ethane Extraction Program

Implemented in 2007, the Incremental Ethane Extraction Program (IEEP) provides $350 million in royalty credits to petrochemical companies that consume incremental ethane for the production of high-value products, such as ethylene and its derivatives. The objective of the IEEP is to supply an additional 60,000 to 85,000 bpd of ethane for petrochemical companies to use as feedstock. The IEEP was being phased out, and ended on December 31, 2021, with the expiry of the Incremental Ethane Extraction Regulation.

The program allowed for a 60-month royalty credit eligibility period. In the 2021 calendar year, 13 of the 16 approved projects were in-service for the program. These 13 in-service projects are capable of providing up to 85,073 bpd of additional ethane or about 93 per cent of the total incremental ethane capacity approved by the minister for the IEEP. In the 2021-22 fiscal year, the department issued approximately $1.4 million in royalty credits to these projects for 2021 production year.

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

The supply and demand for ethane has continued to strengthen over the past few years, and Alberta's petrochemical supply and demand balance is considered stable. Energy will continue to process royalty credits associated with in-service ethane extraction projects that are within their 60-month credit eligibility period.

Enhanced Oil Recovery Program

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

No new applications were received in 2020 under this program, and no new schemes were approved into the program since the program is being phased out and is scheduled to end on December 31, 2026.

Total Crown production from enhanced oil recovery in 2021 was 385,946 cubic metres, which is a decrease of 20,016 cubic metres from the previous year. The Crown royalty volumes from active EOR schemes totaled to 59,188 cubic metres, which translates to approximately $26.5 million in total royalty revenue in 2021. The total royalty revenue increased by over $13.9 million in 2021 from approximately $12.6 million reported in 2020.

The increase in royalty revenue can be explained by a combination of factors. A substantial increase in the West Texas Intermediate (WTI) price of around US$68/bbl in 2021 compared to US$39/bbl in 2020 led to higher royalty rates in 2021. Though there was a drop in total Crown production from EOR due to no new wells under the program and declining production due to maturity, the total Crown royalty volumes increased in 2021 due to schemes reaching the end of their benefit periods. Of the total royalty revenue of $26.5 million, approximately $26.4 million was considered incremental royalty to the Crown that would not have been generated without the program. The incremental royalty revenue has increased by approximately $13.9 million in 2021.

	2018	2019	2020	2021
Total Crown production from EOR	642,834 m^3	502,289 m^3	405,962 m^3	385,946 m^3
Total Crown royalty volumes from EOR	103,891 m^3	69,605 m^3	39,121 m^3	59,188 m^3
Total Crown royalty revenue from EOR	$44.6 million	$27.2 million	$12.6 million	$26.5 million
Incremental Crown royalty revenue from EOR	$41.6 million	$27.0 million	$12.5 million	$26.4 million

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

Performance Measure and Indicator Methodology

Performance Measure 1.a

Alberta's Oil Sands Supply Share of Global Oil Consumption

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

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

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

Sources: Alberta Energy Regulator; International Energy Agency.

Performance Indicator 1.b

Alberta Production

Alberta's crude oil and equivalent production portion of the indicator consists of: Volume (millions of barrels/ day)

The indicator reports the volume of Alberta's annual crude oil and equivalent production. Alberta's crude oil and equivalent production consists of conventional crude oil production, marketable oil sands production (which consists of non-upgraded bitumen and upgraded bitumen), and condensate and pentanes plus. All data for this component of the indicator is taken from the AER reports. Alberta's Energy Resource Sector section in the Annual Report provides an overview of crude oil and equivalent production, calculated from the AER reports. There was a change in the presentation of results from the 2021-24 Business Plan to the 2022-25 Business Plan, on which the present, 2022-23 Annual Report is based. The 2021-24 Business Plan reported the results in thousands of barrels per day. In the 2022-25 Business Plan, the presentation of results was changed to millions of barrels per day. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

The total marketable natural gas production portion of the indicator consists of: Volume (billion cubic feet/ day).

The indicator reports the volume of Alberta's marketable natural gas production. All data for the indicator is taken from the AER reports. Alberta's Energy Resource Sector section provides an overview of marketable natural gas production in Alberta.

In the 2022-25 Business Plan, the reporting of Alberta production results, in billions of cubic feet per day, has been changed to one decimal place, from the previous reporting standard of two decimal places in the 2021-24 Business Plan. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

The 2021-24 Business Plan relied on the Canada Energy Regulator (CER) as a source. In the 2022-25 Business Plan, the AER has replaced the CER as a source for the results for both the oil and gas production portions of the indicator. The previous, 2021-22 Annual Report already included an adjustment that was made in the 2022-25 Business Plan, as the source for both the crude oil and equivalent, and marketable natural gas production components of the indicator was changed from the CER to the AER. This change in reporting is consistent with the general statistical reporting at Energy. The present Annual Report continues to rely on the AER as a source of the production statistics, and is consistent with the 2022-25 Business Plan. The Annual Report also reports the shares of Alberta oil and gas production in the Canadian context, and total percentages of oil and gas leaving the province, but this is reported as supplemental information.

Source: Alberta Energy Regulator.

Performance Indicator 1.c:
Alberta Investment

The Upstream portion of the indicator consists of: CAD$ billions.

This portion of the indicator reports investment in Alberta's Mining, Quarrying, and Oil and Gas Extraction sector. The data for the indicator is taken from Statistics Canada. Data is reported on a calendar year basis. There have been no methodological changes to this portion of the indicator from the 2021-24 Business Plan. However, the presentation of the results has been adjusted. In the 2021-24 Business Plan, the results were rounded off, with no decimal places. In the 2022-25 Business Plan, they were rounded off to one decimal place. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

The Downstream portion of the indicator consists of: CAD$ billions.

This portion of the indicator focuses on the investment impacts of the downstream activity and is explicitly focused on petroleum and coal product manufacturing, and chemical manufacturing; this allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities. The Downstream portion of the indicator is complementary to the Upstream portion. There is no overlap between the data reported by both portions of the indicator, as they are based on different industrial categories.

Just like investment data in the Upstream portion, data for the Downstream portion of the indicator is taken from Statistics Canada. Data is reported on a calendar year basis. There have been no methodological changes to this portion of indicator from the 2021-24 Business Plan. However, the presentation of the results has been adjusted. In the 2021-24 Business Plan, the results for this portion of the indicator were rounded off to two decimal places. In the 2022-25 Business Plan, they were rounded off to one decimal place. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

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

Both portions of the indicator include the investment amounts in Canadian dollars, in the upstream and downstream portions of Alberta's energy industry. The Annual Report also reports the shares of Canadian investment; however, these shares are included as supplemental information, and are not a formal part of the indicator.

Source: Statistics Canada.

Performance Measure 2.a:
Timeliness of Application Processing (Alberta Energy Regulator)

Data used to populate this measure come from the following data sources:

- Integrated Application Registry (IAR) – IAR is the application workflow system used for most applications regulated under the *Oil & Gas Conservation Act*, *Oil Sands Conservation Act*, *Coal Conservation Act*, and *Pipeline Act*.
- PLA AppTracker – The PLA AppTracker is a Microsoft Access solution used to track applications submitted under the *Public Lands Act*.
- AppTracker – The AppTracker is a Microsoft Access solution used to track applications submitted under the *Environmental Protection and Enhancement Act*, the *Water Act*, and applications that are not captured in IAR.
- Onestop – Onestop is the application workflow system developed and implemented to support AER applications, pipelines applictions, *Water Act* approvals, land use applications, new well applications, and reclamation certificattes are processed through OneStop.
- Structured Review Tool (SRT): The SRT provides a consistent and focused way to review elements of submissions that have been identified as high risk or uncertain.

Historical results may shift slightly over time due to the following factors:

- applications not being counted as either meeting or exceeding target until a decision has been issued,
- timing of the data extraction (i.e. incomplete vs a complete data set),
- back dated applications being completed and included in annual values, and
- correcting any manually entered data errors.

2020-21 marked the first year that routine and non-routine applications were tracked and given targets separately. Risks posed to the AER's mandate by energy development are assessed for each application and continually throughout the entire energy development's lifecycle. Contextual factors, such as geographic location, technical characteristics, and operator performance, fluctuate over the energy development life cycle and the AER continuously monitors these through the collection of data from various sources such as reports, inspections, audits and investigations to ensure the risk remains acceptable. All assessments of risk throughout an energy development's life cycle rely on the Government of Alberta's Common Risk Management Framework to ensure that the risk assessment process remains consistent.

Source: Alberta Energy Regulator

Performance Indicator 2.c:
Regulatory Compliance (Alberta Energy Regulator)

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

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

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

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

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

2022-23 data was retrieved on April 12, 2023. The reported numbers include closed, amended and reconsidered enforcement decisions.

Source: Alberta Energy Regulator.

Performance Indicator 2.d:
Pipeline Safety (Alberta Energy Regulator)

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

The AER is responsible for ensuring companies in Alberta develop energy resources in a safe and responsible manner. This includes holding companies accountable for their performance and driving companies to improve. The AER assesses all pipeline incidents to understand the cause and to assess compliance. The economy and industry activity affect the number of operating pipelines at any given time which can impact incident rates. Economic stresses and deterioration of financial conditions of industry can result in maintenance budget reductions.

Companies must have a safety and loss management system (SLMS) that outlines corporate policies and processes to manage pipeline operating risks with respect to the public, the environment, the company, its employees, and property. A company's SLMS guides the reliable operation and understanding of a company's pipeline assets. The goal of an SLMS is to manage all areas of risk, and to direct all activities associated with the safe operation of pipelines. SLMS enables and requires the implementation of risk management and integrity management plans for all pipeline assets.

Source: Alberta Energy Regulator.

Performance Indicator 2.e:
Annual Wells Decommissioned (Alberta Energy Regulator)

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

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

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

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

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

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

Source: Alberta Energy Regulator.

Financial Information

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Reporting Entity and Method Consolidation

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

The reporting entity is the ministry for which the Minister of Energy is accountable. The accounts of the ministry, which includes the department and the entities making up the ministry, are consolidated using the line-byline method, except those designated as government business enterprises (GBEs).

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

GBEs are accounted for on a modified equity basis, with the equity being computed in accordance with the accounting standards applicable to those entities. Under the modified equity method, the accounting policies of the GBEs are not adjusted to conform to those of the government. Inter-entity revenue and expense transactions and related asset and liability balances are not eliminated.

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

Ministry Financial Highlights

Statement of Revenues and Expenses (unaudited)

End of the year March 31, 2023

	2023		2022	Change from	
	Budget (Restated)	Actual	Actual (Restated)	Budget (Restated)	2022 Actual (Restated)
		(in thousands)			
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	$ 10,349,000	$ 16,878,571	$ 11,605,218	$ 6,529,571	$ 5,273,353
Natural Gas and By-Products Royalty	1,458,000	3,595,463	2,226,301	2,137,463	1,369,162
Crude Oil Royalty	1,670,000	3,968,461	1,946,938	2,298,461	2,021,523
Bonuses and Sales of Crown Leases	236,000	464,801	227,937	228,801	236,864
Rentals and Fees	119,000	189,299	152,772	70,299	36,527
Coal Royalty	8,000	145,551	10,383	137,551	135,168
Total Non-Renewable Resource Revenue	13,840,000	25,242,146	16,169,549	11,402,146	9,072,597
Freehold Mineral Rights Tax	96,000	161,142	107,251	65,142	53,891
Transfers from Government of Canada	295,000	436,726	298,356	141,726	138,370
Industry Levies and Licenses	280,759	284,746	288,211	3,987	(3,465)
Other Revenue	2,847	28,767	6,204	25,920	22,563
Net Income (Loss) from Government Business Enterprises					
Alberta Petroleum Marketing Commission	(329,295)	(487,377)	2,059,485	(158,082)	(2,546,862)
Ministry total revenues	14,185,311	25,666,150	18,929,056	11,480,839	6,737,094
Inter-ministry consolidation adjustments	(1,597)	(162)	(462)	1,435	300
Ministry total revenues	14,183,714	25,665,988	18,928,594	11,482,274	6,737,394
Expenses - Directly Incurred					
Ministry Support Services	6,046	4,117	4,482	(1,929)	(365)
Resource Development and Management	75,821	71,590	45,996	(4,231)	25,594
Cost of Selling Oil	144,000	429,381	233,705	285,381	195,676
Carbon Capture and Storage	58,914	42,789	43,665	(16,125)	(876)
Market Access	-	-	866,454	-	(866,454)
Economic Recovery Program	297,200	449,453	300,237	152,253	149,216
Energy Regulation	219,015	223,496	221,629	4,481	1,867
Orphan Well Abandonment	78,500	80,294	77,824	1,794	2,470
Ministry total expenses	879,496	1,301,120	1,793,992	421,624	(492,872)
Inter-ministry consolidation adjustments	(1,597)	(252)	(160)	1,345	(92)
Adjusted ministry total expenses	877,899	1,300,868	1,793,832	422,969	(492,964)
Annual Surplus before inter-ministry consolidation adjustments	13,305,815	24,365,030	17,135,064	11,059,215	7,229,966
Inter-ministry consolidation adjustments	-	90	(302)	90	392
Adjusted annual surplus	$ 13,305,815	$ 24,365,120	$ 17,134,762	$ 11,059,305	$ 7,230,358

Revenue and Expense Highlights

Revenues

Energy's 2022-23 total revenues of $25.67 billion consist of the following:

- **Non-Renewable Resource** revenues totalling $25.2 billion were $11.4 billion higher than budget primarily due to bitumen royalties being $6.53 billion higher than budgeted. The increase was primarily due to higher than forecasted West Texas Intermediate (WTI) and Western Canadian Select (WCS) prices.
- **Freehold Mineral Rights Tax** revenues totalled $161 million and relate to annual taxes on private freehold mineral rights and was $65 million higher than budget. This was caused mainly by a higher unit value for oil and natural gas.
- **Transfers from Government of Canada** totalling $437 million has been recognized as revenue to offset grant expenses incurred for the Site Rehabilitation Program. Of the $1 billion received in 2020-21 from the federal government's COVID-19 Economic Response Plan, $137 million has been recognized as deferred contributions to be returned to the federal government in the 2023-24 fiscal period.
- **Industry levies and licences** totalled $285 million and relate to levies and licenses collected from industry by the Alberta Energy Regulator.
- **Other revenue** totalling $29 million was $26 million higher than budget, primarily due to the prior year expenditure refund for the Crude by Rail program, which ended at the end of the 2021-22 fiscal year.

Expenses

Energy's 2022-23 operating expenditures totalled $1.3 billion, which was $422 million higher than budget. This was primarily related to surpluses for the Carbon Capture and Storage program ($16 million), Ministry Support Services ($1.9 million) and offset by overspending in Cost of Selling Oil ($285 million) and Economic Recovery Program ($152 million).

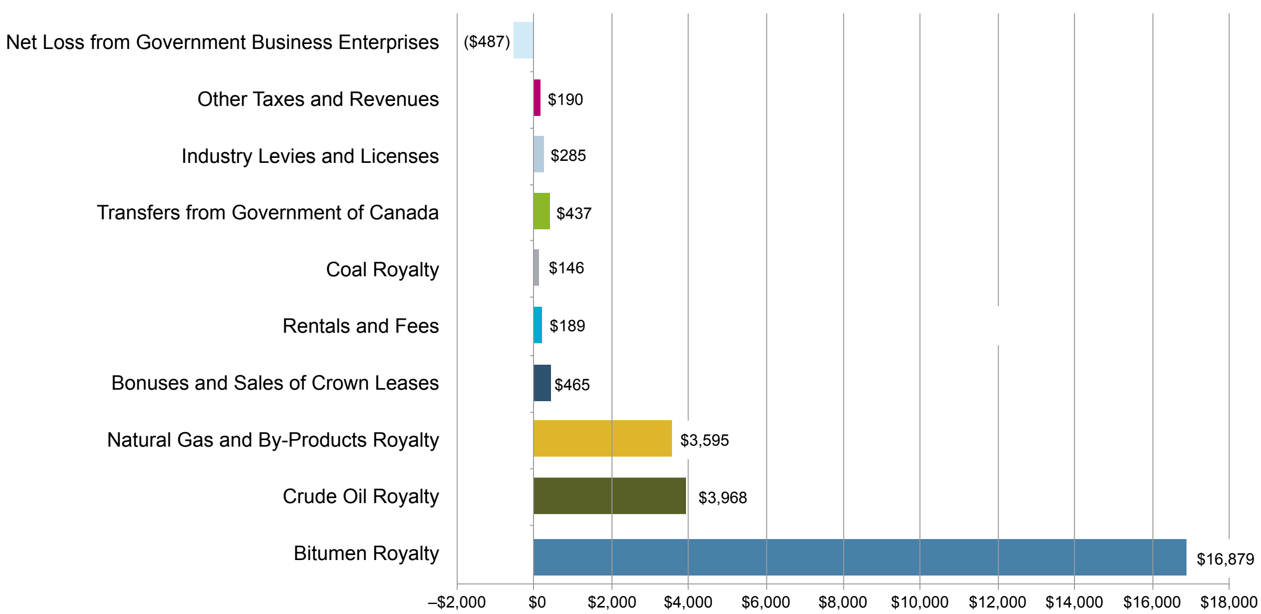
- **Ministry Support Services** – Ministry support services captures the cost incurred by the office of the Minister, Deputy Minister and Corporate Services.
- **Resource Development and Management** – Resource development and management captures the costs incurred by the ministry to support various energy policy and operations activities. These activities have an approved budget of $76 million.
  - **Energy Policy (Budget: $32 million)** – The ministry develops strategic policies to support Alberta's energy and mineral resource markets and electricity systems. The ministry incurred a surplus of $2.7 million primarily due to lower than anticipated labour costs resulting from attrition, delays in hiring and a reduction in discretionary spending.
  - **Energy Operations (Budget: $17 million)** – The ministry oversees Alberta's energy, mines and minerals royalty and tenure systems, which includes the calculation and collection of revenues from energy and mineral royalties, mineral rights leases, and bonuses and rent. The ministry experienced a $2.0 million surplus in Energy Operations, primarily due to lower than anticipated labour costs due to attrition, delays in hiring, and a reduction in discretionary spending.
  - **Industry Advocacy (Budget: $27 million)** – The ministry advocates for Alberta's energy industry in Canada and internationally, which includes activities associated with the Canadian Energy Centre (CEC).

- **Cost of Selling Oil** – This program includes the costs incurred by the Alberta Petroleum Marketing Commission to sell crude oil royalties on behalf of the ministry. These costs were $285 million higher than budget and $196 million higher than previous year actuals, due primarily to higher than forecasted oil prices and increased crude oil royalty in-kind volumes in 2022-23.
- **Carbon Capture and Storage** – This program supports two Carbon Capture and Storage projects in Alberta: the Shell Quest Project and the Alberta Carbon Trunk Line project (ACTL). Due to lower than budgeted payments for CO2 injection volumes, this program spent $16 million less than budget.
- **Economic Recovery Program** – The costs included in this program relate primarily to the Site Rehabilitation Program (SRP). In 2022-23, the ministry incurred $449 million in operating and grant expenditures, which was $152 million higher than budgeted and $149 million higher than previous year actuals. This was primarily due to timing impacts resulting from the federal government's decision to extend the SRP program close to February 2023, necessitating the advancement of expenditures previously anticipated to be spent in 2023-24.
- **Energy Regulation** – This represents the costs incurred by the Alberta Energy Regulator (AER) to support the regulation of Alberta's energy resources. The AER's activities are fully funded by industry levies.
- **Orphan Well Abandonment** expenses, totaling $80 million, relate to the remittance of levies collected on behalf of the Orphan Well Association for the reclamation of abandoned wells, facilities and pipelines that are licensed to defunct licensees, as delegated by the AER.

Breakdown of Revenues (unaudited)

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

2022-23 Actual
(in millions of dollars)



Non-Renewable Resource Revenue

Revenue ($ Millions)	2022-23 Budget	2022-23 Actual
Bitumen Royalty	10,349	16,879
Crude Oil Royalty	1,670	3,968
Natural Gas and By-Products Royalty	1,458	3,595
Bonuses and Sales of Crown Leases	236	465
Rentals and Fees	119	189
Coal Royalty	8	146
Non-Renewable Resource Revenue	**13,840**	**25,242**

- **Bitumen royalties** remained the largest portion of resource royalty revenue. In 2022-23, actual bitumen royalty revenue totaled $16.9 billion, which was $6.5 billion higher than budget. This variance is mainly due to the significantly higher WTI and WCS prices for the fiscal year.
- **Conventional crude oil royalties** contributed $4.0 billion. Conventional crude oil royalties were $2.3 billion, higher than the budget, mainly due to the significantly higher than forecasted WTI prices and production for the fiscal year.
- **Natural gas and by-products** brought in $3.6 billion revenue, and were $2.1 billion above the budget. The favorable variance is attributable to higher than budgeted WTI and Alberta Natural Gas Reference Price.

- **Bonuses and Sales of Crown Leases** totaled $465 million, which was $229 million higher than budget, mainly due to an increase in average price per hectare.
- **Rentals and Fees** totaled $189 million, which was $70 million higher than budget. Rentals and fees revenue is tied to land sales in the current and previous years, where a lease or license holder has to pay rent every year and is also required to pay the first year of rent in full and upfront when their bid wins the bonus auction. Revenue was higher than budget due to an increase in oil sands hectares sold at public auctions which adds to the pool of rent paying leases/licenses.
- **Coal royalty** totaled $146 million, which was $138 million higher than budget, largely due to higher coal prices and increased royalty obligations resulting from a mining operation reaching pay-out status.
- **Other Taxes and Revenue** include freehold mineral rights tax revenue and other revenue.

Royalty Program Adjustments

The ministry has a number of royalty programs under the Alberta Royalty Framework, which ceased accepting new participants as of 2017 and have either been phased out by December 31, 2021 or will be phased out once their regulations expire. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of all royalty programs until they have officially expired.

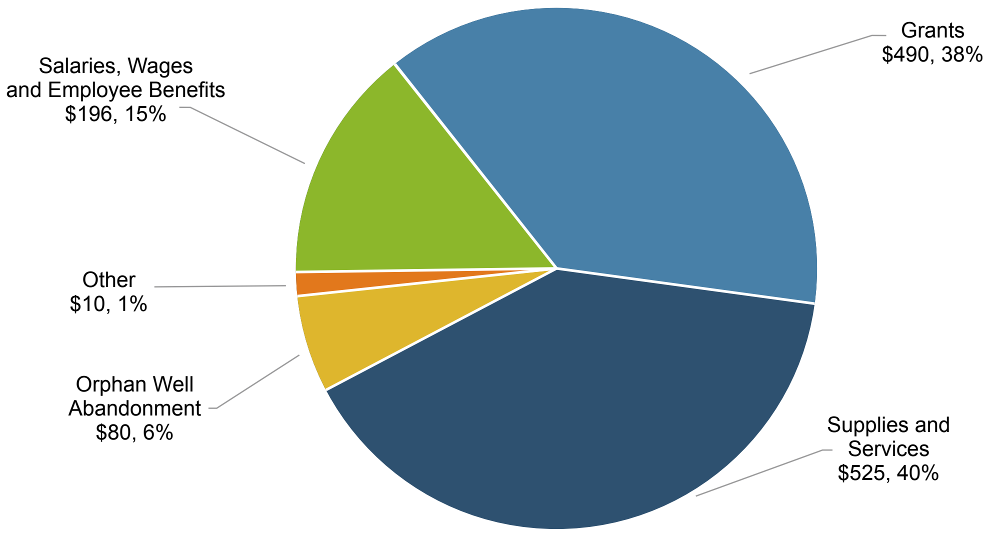
In 2022-23, Non-Renewable Resource Revenues are reported net of the following royalty program adjustments:

	2023	**2022**
	(in thousands)	
Royalty Program:		
Natural Gas Deep Drilling Program	$ 0	$ 94,122
Shale Gas	0	99
Horizontal Oil	0	1,611
Incremental Ethane Extraction Program	0	1,051
Enhanced Oil Recovery Program	28,788	21,020
Proprietary Waiver	8,282	5
Horizontal Gas	0	417
Otherwise Flared Solution Gas	6	23
Total Royalty Program Adjustment	$ 37,076	$ 118,348

Expenses – Directly Incurred Detailed by Object (unaudited)

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

2023 Actual
(in millions)



- **Supplies and Services**, which represented 40 per cent of total operating expense, were the largest component of the ministry's operating expense ($525 million). This consisted primarily of the costs related to costs of selling oil ($429 million). The remainder primarily consisted of ongoing supply requirements for the ministry (i.e., contracts and contract services, materials and supplies, and shared services provided by the Ministry of Service Alberta).
- **Grants**, which represented 38 per cent of total operating expense, were the second largest component of the ministry's operating expense ($490 million), and primarily consisted of payments related to the Site Rehabilitation Program ($437 million), Carbon Capture and Storage projects ($42 million) and the Alberta Petrochemical Incentive Program ($11 million).
- **Salaries, Wages and Employee Benefits**, which represented 15 per cent of total operating expense ($196 million), and primarily support the collection of revenue, development of resource policy, regulatory work provided by the AER, and the overall support and management of ministry operations.
- **Other expenses**, totaling $10 million (1 per cent), primarily consisted of amortization of tangible capital assets ($13 million), which was offset by $6 million of pension recovery.

Supplemental Financial Information

Liabilities

Gas Royalty Deposits

The ministry requires that natural gas producers maintain a deposit, which in most cases, is equal to one-sixth of the prior calendar year's royalties multiplied by the ratio of the long-term gas reference price on the date which the recalculation of the gas deposits is determined to the prior calendar year average gas reference price. The ministry does not pay interest on the deposits. As of March 31, 2023, the Ministry of Energy has gas royalty deposits of $282 million.

Financial Statements of Other Reporting Entities

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Alberta Energy Regulator

Consolidated Financial Statements

For the Year Ended March 31, 2023

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Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Energy Regulator

Report on the Consolidated Financial Statements

Opinion

I have audited the consolidated financial statements of the Alberta Energy Regulator (the Group), which comprise the consolidated statement of financial position as at March 31, 2023, and the consolidated statements of operations, change in net financial assets (net debt), and cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at March 31, 2023, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

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

Other information

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

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

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

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

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

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

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

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

Auditor's responsibilities for the audit of the consolidated financial statements

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

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

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

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit. I remain solely responsible for my audit opinion.

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

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

May 18, 2023
Edmonton, Alberta

Consolidated Statement of Operations

Alberta Energy Regulator
Year Ended March 31, 2023

	2023		2022
	Budget (Note 5, Schedule 3)	Actual	Actual
		(in thousands)	
Revenues			
Administration fees	$ 200,730	$ 201,429	$ 207,921
Orphan fund levies and transfers (Note 6)	78,500	80,294	77,824
Government of Alberta grants	12,811	16,754	16,988
Information, services and fees	1,299	2,576	2,247
Investment income	675	4,085	573
	294,015	305,138	305,553
Expenses			
Energy regulation (Schedule 1)	219,015	223,496	221,629
Orphan well abandonment (Note 6)	78,500	80,294	77,824
	297,515	303,790	299,453
Annual operating surplus (deficit)	(3,500)	1,348	6,100
Accumulated surplus at beginning of year	73,587	73,587	67,487
Accumulated surplus at end of year	$ 70,087	$ 74,935	$ 73,587

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

Consolidated Statement of Financial Position

Alberta Energy Regulator
As At March 31, 2023

	2023	2022
	(in thousands)	
Financial assets		
Cash and cash equivalents (Note 7)	$ 43,171	$ 52,566
Accounts receivable (Note 8)	2,927	1,684
Pension assets (Note 15)	9,903	3,958
	56,001	58,208
Liabilities		
Accounts payable and other accrued liabilities (Note 9)	26,017	26,725
Payable to Orphan Well Association	2,419	1,064
Deferred revenue (Note 10)	7,657	11,362
Deferred lease incentives (Note 12)	9,849	11,315
	45,942	50,466
Net financial assets	10,059	7,742
Non-financial assets		
Tangible capital assets (Note 16)	56,672	57,443
Prepaid expenses and other assets	8,204	8,642
	64,876	66,085
Net assets before spent deferred capital contributions	74,935	73,827
Spent deferred capital contributions (Note 10)	-	240
Net assets		
Accumulated surplus (Note 17)	$ 74,935	$ 73,587

Asset Retirement Obligation (Note 14)
Contractual rights (Note 18)
Contingent liabilities (Note 19)
Contractual obligations (Note 20)

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

Consolidated Statement of Change in Net Financial Assets (Net Debt)

Alberta Energy Regulator
Year Ended March 31, 2023

	2023		2022
	Budget (Note 5, Schedule 3)	Actual	Actual
		(in thousands)	
Annual operating surplus (deficit)	$ (3,500)	$ 1,348	$ 6,100
Acquisition of tangible capital assets (Note 16)	(14,500)	(12,808)	(12,950)
Amortization of tangible capital assets (Note 16)	18,000	13,114	13,921
Net loss on disposal and write-down of tangible capital assets		418	663
Proceeds on disposal of tangible capital assets		47	-
Write-off of leasehold improvements (Note 12)		-	1,056
Decrease in prepaid expenses and other assets		438	743
Net (decrease)/increase in spent deferred capital contributions (Note 10)		(240)	240
Decrease in net debt	-	2,317	9,773
Net financial assets (net debt) at beginning of year	7,742	7,742	(2,031)
Net financial assets at end of year	$ 7,742	$ 10,059	$ 7,742

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

Consolidated Statement of Cash Flows

Alberta Energy Regulator
Year Ended March 31, 2023

	2023	2022
	(in thousands)	
Operating transactions		
Annual operating surplus	$ 1,348	$ 6,100
Non-cash items included in annual operating surplus:		
Amortization of tangible capital assets (Note 16)	13,114	13,921
Write-off of leasehold improvements (Note 12)	-	1,056
Change in pension assets	(5,945)	965
Net loss on disposal and write-down of tangible capital assets (Note 16)	418	663
Bad debt expense (recovery)	34	(16)
Write-off of deferred lease incentives (Note 12)	-	(1,450)
Amortization of deferred lease incentives (Note 12)	(1,466)	(1,567)
	7,503	19,672
Increase in accounts receivable	(1,277)	(212)
Decrease in prepaid expenses and other assets	438	743
(Decrease)/increase in accounts payable and other accrued liabilities	(708)	8,688
Increase/(decrease) in payable to Orphan Well Association	1,355	(878)
(Decrease)/increase in deferred revenue	(3,705)	11,037
Cash provided by operating transactions	3,606	39,050
Capital transactions		
Acquisition of tangible capital assets (Note 16)	(12,808)	(12,950)
Proceeds on disposal of tangible capital assets	47	-
Cash applied to capital transactions	(12,761)	(12,950)
Financing transactions		
(Decrease)/Increase in spent deferred capital contributions (Note 10)	(240)	240
Cash (applied to) provided by financing transactions	(240)	240
(Decrease)/increase in cash and cash equivalents	(9,395)	26,340
Cash and cash equivalents at beginning of year	52,566	26,226
Cash and cash equivalents at end of year	$ 43,171	$ 52,566

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 1 AUTHORITY

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

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

Reporting Entity and Method of Consolidation

The consolidated financial statements reflect the assets, liabilities, revenues and expenses of the AER, which is composed of all components controlled by the AER. The Orphan Fund is a fund retained and administered by the AER. The AER collects an Orphan Fund Levy and a Large Facility Program Orphan Levy, and transfers the funds to the Orphan Well Association through the Orphan Fund. The AER also transfers funds for first time licensee application fees, including regulator directed transfer fees, and forfeited security deposits through the Orphan Fund. The AER and the Orphan Fund are consolidated using the line-by-line method.

Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting. The AER recognizes revenue from administration fees at their realizable value. Cash received for which services have not been provided by year end is recognized as deferred revenue.

Government of Alberta Grants

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

Provincial grants without stipulations for the use of the transfer are recognized as revenue when the transfer is authorized and the AER meets the eligibility criteria (if any). Provincial grants with stipulations for the use of the transfer are recognized as deferred revenue and subsequently recognized when the AER meets the stipulations.

Investment Income

Investment income includes interest income.

Expenses

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

Employee future benefits

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

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

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

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

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

Basis of Financial Reporting (continued)

Employee future benefits (continued)

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 11.2 years (2022 - 11.2 years).

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

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

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

Valuation of financial assets and liabilities

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

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

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

Financial assets

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

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

Cash and cash equivalents

Cash comprises cash on hand, externally restricted cash and demand deposits.

Accounts receivable

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

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

Basis of Financial Reporting (continued)

Liabilities

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

Deferred lease incentives

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

Environmental Liabilities

Liability for Contaminated Sites:

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

A liability for remediation of a contaminated site may arise from an operation that is either in productive use or no longer in productive use and may also arise from an unexpected event resulting in contamination. The resulting liability is recognized when all of the following criteria are met:

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

Contingent Liabilities

A contingent liability is recognized when:

i. there is an existing condition or situation;
ii. there is an expected future event that will resolve the uncertainty as to whether a present obligation to sacrifice economic benefits exists;
iii. it is likely that a future event will confirm that a liability has been incurred at the date of the financial statements; and
iv. a reasonable estimate of the amount can be made.

Non-financial assets

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

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

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

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

Basis of Financial Reporting (continued)

Tangible capital assets

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

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

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

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

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

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

Prepaid expenses

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

Measurement uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount, whenever estimates are used. The amounts recognized for amortization of tangible capital assets are based on estimates of the useful life of the related assets. Accrued defined benefit obligations are subject to measurement uncertainty due to the use of actuarial assumptions. The resulting estimates are within reasonable limits of materiality and are in accordance with the AER's significant accounting policies.

Estimates of contingent liabilities for contaminated sites are subject to measurement uncertainty because the existence and extent of contamination, the responsibility for clean-up, and the timing and costs of remediation cannot be reasonably estimated in all circumstances. The degree of measurement uncertainty cannot be reasonably determined.

Note 3 CHANGE IN ACCOUNTING STANDARDS

Effective April 1, 2022, the AER adopted the new accounting standards PS 3280 Asset Retirement Obligations. There was no material impact on the AER’s consolidated financial statements, as discussed in Note 14.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 4 FUTURE CHANGES IN ACCOUNTING STANDARDS

The Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2023:

PS 3400 Revenue (effective April 1, 2023)
This standard provides guidance on how to account for and report on revenue, and specifically, it differentiates between revenue arising from exchange and non-exchange transactions.

PS 3160 Public Private Partnerships (effecitve April 1, 2023)
This standard provides guidance on how to account for public private partnerships between public and private sector entities, where the public sector entity procures infrastructure using a private sector partner.

Management is currently assessing the impact of these standards on the consolidated financial statements. These standards are not expected to have a significant impact on the AER's consolidated financial statements.

Note 5 BUDGET

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

Note 6 ORPHAN WELL ABANDONMENT
(in thousands)

The Government of Alberta has delegated the authority to manage the abandonment and reclamation of wells, facilities, and pipelines that are licensed to defunct licensees to the Orphan Well Association. The AER collects an Orphan Fund Levy and a Large Facility Program Orphan Levy, and transfers the funds to the Orphan Well Association through the Orphan Fund. The AER also transfers funds for first time licensee application fees, including regulator directed transfer fees, and forfeited security deposits through the Orphan Fund. During the year ended March 31, 2023, the AER collected and transferred $78,090 (2022 - $73,788) in levies, $669 (2022 - $436) in application fees and $1,535 (2022 - $3,600) in forfeited security deposits.

Note 7 CASH AND CASH EQUIVALENTS
(in thousands, unless otherwise noted)

Cash and cash equivalents are held in an account with a Canadian chartered bank and earn interest calculated based on the average monthly cash balance. The funds are available to be withdrawn upon request. During the year ended March 31, 2023, the AER earned interest at an annual average rate of 3.5% (2022 - 0.8%).

Cash and cash equivalents includes restricted funds of $7,447 (2022 - $11,159), as reflected in deferred revenue (discussed in Note 10).

Note 8 ACCOUNTS RECEIVABLE
(in thousands)

Accounts receivable are unsecured and non-interest bearing.

	2023			2022
	Gross amount	Allowance for doubtful accounts	Net recoverable value	Net recoverable value
Accounts receivable	$ 3,187	$ (260)	$ 2,927	$ 1,684

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 9 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

(in thousands)

	2023	2022
Trade and other accrued liabilities	$ 9,743	$ 12,481
Lease termination payable	5,820	7,376
Accrued salaries and benefits	10,454	6,868
	$ 26,017	$ 26,725

Note 10 DEFERRED REVENUE

(in thousands)

Deferred revenue consists of the following:

	2023	2022
Deferred contributions[1]	$ 7,447	$ 11,159
Unearned revenue	210	203
	$ 7,657	$ 11,362
Spent deferred capital contributions	-	240
	$ 7,657	$ 11,602

(1) Deferred contributions

	2023			2022
	Government of Alberta	Other	Total	Total
Balance at beginning of year	$ 10,837	$ 322	$ 11,159	$ 143
Cash contributions received/receivable during year	12,811	347	13,158	28,369
Less: amounts recognized as revenue	(16,514)	(356)	(16,870)	(17,113)
Transferred to spent deferred capital contributions	-	-	-	(240)
Balance at end of year	$ 7,134	$ 313	$ 7,447	$ 11,159

Note 11 FINANCIAL INSTRUMENTS

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

Financial Risk Management

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

(a) Liquidity risk

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 11 FINANCIAL INSTRUMENTS (continued)

(b) Credit risk

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

Note 12 DEFERRED LEASE INCENTIVES

(in thousands)

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

	2023			2022
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 9,370	$ 1,945	$ 11,315	$ 14,332
Write-off of lease incentives[(1)]	-	-	-	(1,450)
Amortization	(1,136)	(330)	(1,466)	(1,567)
Balance at end of year	$ 8,234	$ 1,615	$ 9,849	$ 11,315

(1) In 2022, the AER exited a portion of the lease for its Calgary Head Office. As a result, the AER wrote off the related leasehold improvements and lease incentives pertaining to this office space.

Note 13 ENVIRONMENTAL LIABILITIES

(in thousands, unless otherwise noted)

The AER has a mandate to protect public safety and the environment. As at March 31, 2023, the AER is not responsible, nor has it accepted responsibility, for performing remediation and reclamation work at contaminated sites. The AER has $nil (2022 - $nil) environmental liabilities recorded.

As at March 31, 2023, the AER is administering 29 (2022 – 29) legacy sites. Of these sites, during the year ended March 31, 2023, the AER identified one (2022 – two) site as having immediate public safety and environmental risk, and the AER needed to take appropriate action to mitigate these risks. During the year ended March 31, 2023, the AER incurred $3 (2022 - $9) in costs to mitigate immediate public safety and environmental risks. Costs to mitigate immediate public safety or environmental risks are costs where the AER has completed protective or remediation work at legacy sites. Costs for ongoing assessment and monitoring are included.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 14 ASSET RETIREMENT OBLIGATION

Tangible capital assets are assessed for asset retirement obligations annually. Asset retirement obligations are initially measured as of the date the legal obligation was incurred, based on management's best estimate of the amount required to retire tangible capital assets and subsequently re-measured taking into account any new information and the appropriateness of assumptions used. At March 31, 2023, the estimate of the liability is insignificant and therefore no liability was recognized. During the year ended March 31, 2023, the AER incurred $nil (2022 - $nil) in costs to settle the obligation.

Note 15 EMPLOYEE FUTURE BENEFITS

(in thousands, unless otherwise noted)

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. For the year ended March 31, 2023, the expense for these pension plans is equal to the contributions of $12,207 (2022 - $12,253) and is included in salaries, wages and employee benefits on Schedule 1. The AER is not responsible for future funding of the plan deficit other than through contribution increases.

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

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

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2021. The accrued benefit obligation as at March 31, 2023 is based on the extrapolation of the results of this valuation. The effective date of the next required funding valuation for SEPP is December 31, 2024.

Pension plan assets are valued at market values. During the year ended March 31, 2023, the weighted average actual return on plan assets was -1.9% (5.2% in 2022).

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

Accrued benefit obligations	2023	2022
Discount rate	5.4%	4.5%
Rate of compensation increase	4.0% until March 31, 2023, 6.0% until March 31, 2024, 3.0% thereafter	4.0% until March 31, 2023, 3.0% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2023	2022
Discount rate	4.5%	4.4%
Expected rate of return on plan assets	4.5%	4.4%
Rate of compensation increase	4.0% until March 31, 2023, 3.0% thereafter	0% until March 31, 2022, 3.0% thereafter

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 15 EMPLOYEE FUTURE BENEFITS (continued)

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

	2023	2022
Market value of plan assets	$ 81,577	$ 76,893
Accrued benefit obligations	(67,126)	(70,739)
Plan surplus	14,451	6,154
Unamortized actuarial gains	(4,548)	(2,196)
Pension assets	$ 9,903	$ 3,958

(in thousands, unless otherwise noted)

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

	2023	2022
Current period benefit cost	$ 3,921	$ 4,045
Interest cost	3,277	3,197
Expected return on plan assets	(3,462)	(3,227)
Amortization of actuarial (gains)/losses	(67)	251
	$ 3,669	$ 4,266

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

	2023	2022
Benefits paid	$ 4,189	$ 5,009
AER contributions	9,615	3,298
Employees' contributions	751	684

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

	2023	2022
Equity securities	45.4%	44.1%
Debt securities	24.3%	23.4%
Alternatives	18.5%	20.0%
Other	11.8%	12.5%
	100.0%	100.0%

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 16 TANGIBLE CAPITAL ASSETS

(in thousands)

	2023					2022
	Land	**Leasehold improvements**	**Furniture and equipment (1)**	**Computer hardware and software**	**Total**	**Total**
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years		
Historical cost (2)						
Beginning of year	$ 282	$ 46,366	$ 12,400	$ 138,338	$ 197,386	$ 208,404
Additions	-	1,398	803	10,607	12,808	12,950
Disposals, including write-downs	-	(141)	(301)	(8,689)	(9,131)	(23,968)
	282	47,623	12,902	140,256	201,063	197,386
Accumulated amortization						
Beginning of year	$ -	$ 24,384	$ 9,529	$ 106,030	$ 139,943	$ 148,271
Amortization expense	-	2,737	770	9,607	13,114	13,921
Effect of disposals, including write-downs	-	(132)	(270)	(8,264)	(8,666)	(22,249)
	-	26,989	10,029	107,373	144,391	139,943
Net book value at March 31, 2023	$ 282	$ 20,634	$ 2,873	$ 32,883	$ 56,672	
Net book value at March 31, 2022	$ 282	$ 21,982	$ 2,871	$ 32,308		$ 57,443

(1) Furniture and equipment includes organization-owned vehicles, office equipment, furniture and other equipment.

(2) Historical costs includes work-in-progress at March 31, 2023 totalling $6,381 (2022 -$2,297) comprised of: computer hardware and software includes work-in-progress totalling $6,369 (2022 - $2,297) and leasehold improvements $12 (2022 - $nil).

Note 17 ACCUMULATED SURPLUS

(in thousands)

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

	2023			2022
	Investments in tangible capital assets (1)	**Unrestricted net assets**	**Total**	**Total**
Balance at beginning of year	$ 48,073	$ 25,514	$ 73,587	$ 67,487
Annual operating surplus	-	1,348	1,348	6,100
Net investment in tangible capital assets (1)	365	(365)	-	-
Balance at end of year	$ 48,438	$ 26,497	$ 74,935	$ 73,587

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 18 CONTRACTUAL RIGHTS

(in thousands)

Contractual rights are rights of the AER to economic resources arising from contracts or agreements that will result in both assets and revenues in the future when the terms of those contracts or agreements are met.

During the year ended March 31, the AER collected the following amounts for its contractual rights under operating subleases:

	2023	2022
Contractual rights from operating subleases	$ 543	$ 316

As at March 31, 2023, estimated amounts that will be received or receivable for each of the next five years are as follows:

2023-24	550
2024-25	433
2025-26	439
2026-27	182
2027-28	-
	$ 1,604

Note 19 CONTINGENT LIABILITIES

(in thousands)

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

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate. As at March 31, 2023, accruals totalling $1,312 (2022 - $1,359) have been recognized as a liability.

The AER has identified various sites where contamination may exist and the level of contamination is unknown at this time. As at March 31, 2023, no liability has been recognized for these sites as further testing and evaluation is required to determine the extent of immediate actions necessary. No liability for remediation on other sites has been recognized as the AER becoming responsible for these sites is not determinable; the AER does not expect to give up any future economic benefits; no reasonable estimate of the amount can be made; or a combination of these factors. The AER's ongoing efforts to assess contaminated sites may result in environmental remediation liabilities related to newly identified sites, or change in the assessment or intended use of existing sites. Any change to the environmental liabilities will be accrued in the year in which they are assessed as likely and measurable.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2023

Note 20 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2023, the AER had contractual obligations totalling $125,189 (2022 - $146,445).

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

As at March 31, 2023, estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2023-24	$ 50,733
2024-25	16,824
2025-26	10,891
2026-27	10,116
2027-28	9,675
Thereafter	26,950
	$ 125,189

Note 21 ASSETS UNDER ADMINISTRATION

(in thousands)

The AER administers security deposits in accordance with specified acts and regulations. Security deposits are held on behalf of depositors with no power of appropriation and therefore are not reported in these consolidated financial statements. The AER does not have any financial risk associated with security collected. Security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria. Security may be forfeited and transferred to the Orphan Well Association for the cost of suspension, abandonment, site decontamination and surface land reclamation.

As at March 31, 2023, assets under administration included the following types of security deposits:

	2023				2022
	Cash	Letters of credit	Surety Bond	Total	Total
Liability Management Rating programs and landfills	$ 102,539	$ 281,789	$ -	$ 384,328	$ 368,103
Mine Financial Security program	67,079	1,245,343	247,312	1,559,734	1,520,516
Other programs	11,061	10,923	-	21,984	21,134
	$ 180,679	$ 1,538,055	$ 247,312	$ 1,966,046	$ 1,909,753

Note 22 COMPARATIVE FIGURES

Certain 2022 figures have been reclassified, where necessary, to conform to the 2023 presentation.

Note 23 APPROVAL OF CONSOLIDATED FINANCIAL STATEMENTS

These consolidated financial statements were approved by the AER Board of Directors on May 18, 2023.

Energy Regulation Expenses - Detailed By Object

Alberta Energy Regulator
Year Ended March 31, 2023
Schedule 1

	2023	2022
	(in thousands)	
Salaries, wages and employee benefits	$ 147,068	$ 132,712
Consulting services	22,608	26,539
Buildings	18,848	27,305
Computer services	17,801	17,710
Amortization of tangible capital assets	13,114	13,921
Administrative	1,703	1,274
Travel and transportation	1,640	1,292
Loss on disposal and write-down of tangible capital assets	418	663
Equipment rent and maintenance	296	205
Abandonment and enforcement	-	8
	$ 223,496	$ 221,629

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2023
Schedule 2

	2023				2022 Restated [4]
	Base salary	Other cash benefits [1]	Other non-cash benefits [2]	Total	Total
			(in thousands)		
Position					
Board Members [3]	$ 460	$ -	$ 38	$ 498	$ 468
President and Chief Executive Officer	342	40	83	465	464
Chief Hearing Commissioner [4]	224	11	59	294	276
Chief Operations Officer	271	15	84	370	347
Executive Vice-President, Law and General Counsel [5]	230	11	84	325	-
Vice-President of Finance and Chief Financial Officer	239	9	87	335	327
Vice-President of People, Culture and Learning [6]	225	14	74	313	-
Former Executive Vice-President, Law and General Counsel [7]	41	19	12	72	346

(1) Other cash benefits include payments in lieu of vacation, pension and health benefits, as well as vehicle allowances and other cash reimbursements.

(2) Other non-cash benefits include contributions to all benefits as applicable, including employer's share of all employee benefits and contributions or payments made on behalf of employees, including pension, supplementary retirement plans, health care and payments made for professional memberships, tuition fees, parking and other taxable benefits.

(3) The incumbent Board of Directors consists of eight members. Seven Board Members are remunerated with monthly honoraria as per rates prescribed in the Orders in Council, one Board Member is unpaid. Two new Board Members were appopointed on August 22, 2022 and March 14, 2023, and one member was rescinded on October 24, 2022.

(4) The 2022 figures have been restated to include the two individuals who occupied this position during 2022. In October 2021, an incumbent was appointed as acting Chief Hearing Commissioner and held the position until April 14, 2022.

(5) The incumbent held the position effective May 23, 2022.

(6) Effective April 6, 2022 the position became a voting member of the Executive Leadership Team.

(7) The incumbent retired on May 24, 2022.

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2023
Schedule 2 (continued)

SEPP AND SRP RETIREMENT BENEFITS

(in thousands)

The costs detailed below are only for those employees, included in Schedule 2, who were employed during the years ended March 31, 2022 and 2023, and participated in the SEPP and SRP maintained by the AER. The SEPP and SRP provide retirement benefits to compensate senior staff who do not participate in the Government of Alberta's management pension plans.

	2023			2022
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Executive Vice-President, Law and General Counsel[5]	$ 24	$ (1)	$ 23	$ -
Vice-President of Finance and Chief Financial Officer	33	(1)	32	39
Vice-President of People, Culture and Learning[6]	28	-	28	-

The SEPP and SRP accrued obligation for each executive employed by the AER during the years ended March 31, 2022 and 2023 is outlined in the following table:

Position	Accrued obligation April 1, 2022	Changes in accrued obligation	Accrued obligation March 31, 2023	Accrued obligation March 31, 2022
Executive Vice-President, Law and General Counsel[5]	$ 185	$ 13	$ 198	$ 185
Vice-President of Finance and Chief Financial Officer	57	36	93	57
Vice-President of People, Culture and Learning[6]	46	24	70	46

Consolidated Actual Results Compared With Budget

Alberta Energy Regulator
Year Ended March 31, 2023
Schedule 3

	Budget (Note 5)	Adjustments [1]	Adjusted budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 200,730	$ 640	$ 201,370	$ 201,429
Orphan fund levies and transfers	78,500	-	78,500	80,294
Government of Alberta grants	12,811	10,800	23,611	16,754
Information, services and fees	1,299	203	1,502	2,576
Investment income	675	3,177	3,852	4,085
	294,015	14,820	308,835	305,138
Expenses				
Energy regulation	219,015	15,320	234,335	223,496
Orphan well abandonment	78,500	-	78,500	80,294
	297,515	15,320	312,835	303,790
	(3,500)	(500)	(4,000)	1,348
Capital				
Capital investment	14,500	(5,500)	9,000	12,808
Less: Amortization of tangible capital assets	(18,000)	5,000	(13,000)	(13,114)
Net loss on disposal and write-down of tangible capital				(418)
Proceeds on disposal of tangible capital assets				(47)
Net capital investment	(3,500)	(500)	(4,000)	(771)
Surplus	$ -	$ -	$ -	$ 2,119

(1) Adjustments reflect changes to the original budget approved by the Treasury Board. These adjustments reflect an extension of grant funding to accommodate work completed in 2023 for the Public Geoscience grant received in 2022, higher investment income, a reduction to amortization expense and capital spending, and higher energy regulation expenses to address inflationary increases for certain expenditures.

Related Party Transactions

Alberta Energy Regulator
Year Ended March 31, 2023
Schedule 4

The AER, in the normal course of business, entered into various transactions with entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. These entities are considered to be related parties of the AER. Related parties also include key management personnel and close family members of those individuals in the AER. In 2023, there were no amounts or transactions, other than compensation, between the AER and its key management personnel. Key management personnel compensation is disclosed in Schedule 2.

Related Party Transactions with Government of Alberta Entities

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

	Entities in the Ministry of Energy		Other entities	
	2023	**2022**	**2023**	**2022**
	(in thousands)		*(in thousands)*	
Revenues				
Government of Alberta grants	$ 16,754	$ 16,988	$ -	$ -
Information, services and fees	333	334	671	485
	$ 17,087	$ 17,322	$ 671	$ 485

	Entities in the Ministry of Energy		Other entities	
	2023	**2022**	**2023**	**2022**
	(in thousands)		*(in thousands)*	
Expenses				
Computer services	$ 341	$ 386	$ 3,441	$ 3,573
Buildings	-	-	433	400
Administrative	-	-	515	370
Consulting services	-	-	174	187
	$ 341	$ 386	$ 4,563	$ 4,530
Receivable from	$ 130	$ 137	$ 13	$ 6
Prepaid expenses and other assets	$ -	$ -	$ 36	$ 36
Payable to	$ -	$ -	$ 1,987	$ 1,307
Deferred revenue	$ 7,134	$ 10,837	$ 200	$ 259
Contractual obligations [a]	$ -	$ -	$ 3,869	$ 4,850

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

Alberta Petroluem Marketing Commission
Consolidated Financial Statements
For the Year Ended March 31, 2023

Table of Contents

Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Consolidated Financial Statements

Opinion

I have audited the consolidated financial statements of the Alberta Petroleum Marketing Commission (the Group), which comprise the consolidated statement of financial position as at March 31, 2023, and the consolidated statements of income (loss) and comprehensive income (loss), changes in deficit, and cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at March 31, 2023, and its financial performance, and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for opinion

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

Other information

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

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

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

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

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

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

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

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

Auditor's responsibilities for the audit of the consolidated financial statements

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

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

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

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit. I remain solely responsible for my audit opinion.

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

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

June 2, 2023
Edmonton, Alberta

Consolidated Statement of Financial Position

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

As at ($000s)	Note	**March 31, 2023**	March 31, 2022
ASSETS			
Cash and cash equivalents	6	**45,337**	26,701
Restricted cash	7	**76,633**	72,568
Accounts receivable	8	**463,438**	656,041
Inventory	9	**70,607**	95,704
Total current assets		**656,015**	851,014
Investment in KXL Expansion Project	10	**33,000**	82,000
Investment in North West Redwater Partnership	12	**230,324**	250,601
Corporate assets		**606**	599
Intangible assets	11	**6,652**	7,717
Inventory	9	**6,877**	6,877
Total assets		**933,474**	1,198,808
LIABILITIES			
Accounts payable and accrued liabilities	13	**389,109**	548,310
Due to the Department of Energy	14	**211,359**	218,949
Short term debt	15	**1,240,659**	2,031,427
Accrued interest payable	16	**27,483**	7,554
License fee provision	18	**—**	3,590
Lease liabilities		**64**	52
Sturgeon Refinery Processing Agreement provision	19	**—**	299,000
Total current liabilities		**1,868,674**	3,108,882
Long term debt	17	**1,378,392**	427,493
License fee provision	18	**87,000**	193,628
Lease liabilities		**374**	394
Sturgeon Refinery Processing Agreement provision	19	**669,000**	51,000
Total liabilities		**4,003,440**	3,781,397
SHAREHOLDERS' DEFICIT			
Deficit		**(3,069,966)**	(2,582,589)
Total liabilities and shareholders' deficit		**933,474**	1,198,808

Commitments note 21

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

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

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

		Years ended March 31,	
($000s)	**Note**	**2023**	2022
REVENUES			
Refinery sales		**2,733,082**	2,381,861
Other income	23	**—**	71,250
Marketing fee income		**12,050**	11,201
		2,745,132	2,464,312
Finance income		**2,580**	26,538
Total revenue		**2,747,712**	2,490,850
EXPENSES			
Refinery feedstock purchases		**1,884,148**	1,759,753
Refinery tolls		**878,508**	780,451
Turnaround expenditures	24	**164,279**	23,604
General and administrative	25	**11,560**	13,062
Depreciation and amortization		**1,166**	1,110
Gain on foreign exchange		**(5,802)**	(3,574)
Finance costs	27	**101,492**	88,663
Gain from North West Redwater Partnership	12	**(97,361)**	(2,611)
Change to loss provision for Sturgeon Refinery Processing Agreement	19	**289,250**	(2,218,355)
Change to Sturgeon Refinery credit loss provision	20	**16,903**	(267)
Fair value gain on investment in KXL Expansion Project	10	**(9,054)**	(10,471)
Total expenses		**3,235,089**	431,365
Net income (loss) and comprehensive income (loss)		**(487,377)**	2,059,485

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

Consolidated Statement of Cash Flows

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

		Years ended March 31,	
($000s)	**Note**	**2023**	2022
OPERATING ACTIVITIES			
Net income (loss) and comprehensive income (loss)		**(487,377)**	2,059,485
Adjusted for items not involving cash:			
Amortization of premium on long term debt	17	**(16,518)**	(7,860)
Depreciation and amortization		**1,166**	1,110
Accretion expenses		**37,170**	79,818
Fair value gain on investment in KXL Expansion Project	10	**(9,054)**	(10,471)
Unrealized foreign exchange gain		**(5,716)**	(3,324)
Gain from North West Redwater Partnership	12	**(97,361)**	(2,611)
Change for credit loss provision	20	**17,060**	(63)
Change to loss provision for Sturgeon Refinery Processing Agreement	19	**289,250**	(2,218,355)
Interest received from term loan receivable		**—**	251,486
Accrued interest on term loan		**—**	(26,326)
Changes in accrued interest payable	16	**19,929**	4,553
Changes in non-cash working capital	29	**29,784**	(127,155)
Net cash (used in) provided by operating activities		**(221,667)**	287
FINANCING ACTIVITIES			
Payment of lease liabilities		**(61)**	(32)
Proceeds from short term and long term debt	15, 17	**2,492,206**	2,487,156
Repayment of short term debt	15	**(2,315,557)**	(1,917,015)
Net cash provided by financing activities		**176,588**	570,109
INVESTING ACTIVITIES			
Liquidation proceeds received on KXL investment		**63,770**	37,795
Debt guarantee payment for KXL Expansion Project		**—**	(1,035,002)
Transaction costs attributable to acquiring partnership interest		**—**	(56,235)
Funds from term loan receivable		**—**	314,734
Expenditures on property, plant, and equipment		**(55)**	(167)
Net cash provided by (used in) investing activities		**63,715**	(738,875)
Net change in cash and cash equivalents		**18,636**	(168,479)
Cash and cash equivalents, beginning of year		**26,701**	195,180
Cash and cash equivalents, end of year		**45,337**	26,701
Cash paid			
Interest received		**2,580**	251,698
Interest paid		**(60,911)**	(12,152)
Taxes		**—**	(4,327)

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

Consolidated Statement of Changes in Deficit

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

($000s)	
Deficit, March 31, 2021	(4,642,074)
Net income and comprehensive income	2,059,485
Deficit, March 31, 2022	(2,582,589)
Deficit, March 31, 2022	**(2,582,589)**
Net loss and comprehensive loss	**(487,377)**
Deficit, March 31, 2023	**(3,069,966)**

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

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

1. AUTHORITY AND STRUCTURE

The Alberta Petroleum Marketing Commission ("APMC" or the "Commission") is a corporation created under the *Petroleum Marketing Act* (Alberta) to act as agent for the Government of Alberta ("GOA" or "Crown") in accepting delivery and dealing with the Crown's royalty share of hydrocarbons; and engaging in other hydrocarbon-related activities in a manner that is in the public interests of Albertans. Under this mandate, the APMC performs commercial activities to receive and market crude oil royalty volumes on behalf of the Crown, and to transact or invest in energy projects which seek to expand access to global energy markets or otherwise maximize the long-term sustainable value of the Crown's resources. The Commission is overseen by a majority-independent Board of Directors and operates at arm's length from the GOA; however, it is accountable to and may receive policy and other direction from the Alberta Minister of Energy. The consolidated financial statements disclose the transactions the APMC incurs while marketing crude oil on behalf of the Crown, and the APMC's investment in the North West Redwater Partnership ("NWRP" or the "Partnership"), the Sturgeon Refinery ("Refinery"), and the KXL Expansion Pipeline ("KXL Expansion Project") through newly created subsidiaries in 2020.

The Commission operates a Business Development group to identify and analyze business ideas and proposals that provide strategic value to Alberta and are financially feasible.

As an agent of the GOA, the Commission is not subject to Canadian federal or provincial corporate income taxes.

The Commission is located at the following address: 1050, 250 – 5 Street S.W., Calgary, Alberta, T2P 0R4. These consolidated financial statements were authorized for issue by the Board of Directors on June 2, 2023.

The Commission conducts its principal business in four reportable operating segments (note 30).

2. BASIS OF PRESENTATION

(a) Statement of compliance

The consolidated annual financial statements (the "Annual Financial Statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as published by the International Accounting Standards Board ("IASB") and related interpretations as issued by the IFRS Interpretations Committee ("IFRIC").

(b) Basis of measurement

The Annual Financial Statements have been prepared on a historical cost basis except for the Investment in KXL Expansion Project that has been measured at fair value.

(c) Functional and presentation currency

The Annual Financial Statements are presented in Canadian dollars ("CAD"), which is also the APMC's functional and presentation currency.

(d) Use of estimates, assumptions and judgements

The preparation of the Annual Financial Statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments used in the preparation of the Annual Financial Statements are described in note 4.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

(e) Comparative figures

Certain comparative figures on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) have been restated to conform to the current period's presentation.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in the Annual Financial Statements.

(a) Basis of consolidation

The Annual Financial Statements include the accounts of the APMC and its wholly owned subsidiaries. Subsidiaries are consolidated from the date the Commission obtains control and continues to be consolidated until the date such control ceases. Control is achieved when the APMC is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Some of the APMC’s subsidiaries have a December 31 year end for statutory purposes, however, the results of the subsidiaries are prepared for the same reporting period as the APMC, using consistent accounting policies. All inter-entity transactions have been eliminated upon consolidation between the APMC and its subsidiaries in these Annual Financial Statements. The APMC’s operations are viewed as four operating segments by the chief executive officer of the Commission for the purpose of resource allocation and assessing performance.

The following table details the APMC’s subsidiaries:

Name	Principal activities	Country of Incorporation	% Equity Interest
2254737 Alberta Ltd. [1]	Facilitate APMC’s financial support of the Canadian portion of the KXL Expansion Project and assist with various governance related matters	Canada	100%
2254755 Alberta Ltd. [1]	Facilitate APMC’s financial support for the project costs related to the Canadian portion of the KXL Expansion Project	Canada	100%
2254753 Alberta Ltd. [1]	Facilitate APMC’s financial support for the project costs related to the US portion of the KXL Expansion Project and assist with various governance related matters	Canada	100%
2254746 Alberta Ltd. [1, 2]	Facilitate APMC’s financial support for the project costs related to the US portion of the KXL Expansion Project	Canada	100%
2254746 Alberta Sub. Ltd. [1]	Facilitate APMC’s financial support for the project costs related to the US portion of the KXL Expansion Project	USA	100%
APMC (Redwater) L.P.	Holds a 50% interest in the North West Redwater Partnership	Canada	100%
APMC (Redwater) Corp.	General partner in APMC (Redwater) L.P.	Canada	100%

1. Denotes subsidiaries with a December 31 year end.
2. 2254746 Alberta Ltd. Is the sole shareholder of 2254746 Alberta Sub. Ltd.

(b) Joint arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control only exists when decisions about the activities that most significantly affect the returns of the investee are unanimous. Joint arrangements can be classified as either a joint operation or a joint venture. The classification of joint arrangements requires judgment. In determining the classification of its joint arrangements, the Commission reviews numerous criteria including the contractual rights and obligations of each investor, whether the legal structure of

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

the joint arrangement gives the entity direct rights to the assets and obligations for the liabilities, and whether substantially all of the economic output and benefit is to be received by the parties over the estimated economic life of the asset.

Where the APMC has rights to the assets and obligations for the liabilities of a joint arrangement, such arrangement is classified as a joint operation and the Commission's proportionate share of the joint operation's assets, liabilities, revenues and expenses are included in the consolidated financial statements, on a line-by-line basis.

Where the APMC has rights to the net assets of an arrangement, the arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the Commission's initial investment is recognized at cost and subsequently adjusted for the APMC's share of the joint venture's income or loss, less distributions received. When the APMC transacts with a joint venture, profits and losses resulting from the transactions are recognized in the Commission's financial statements only to the extent of interests in the joint venture that are not related to the APMC. Should the Commission's share of losses of a joint venture exceed APMC's interest in that joint venture, the Commission discontinues recognizing its share of further losses. Additional losses are recognized only to the extent that the APMC has incurred legal or constructive obligations or made payments on behalf of the joint venture.

An investment in a joint venture is accounted for using the equity method from the date on which the APMC obtains joint control in the investee. On acquisition of the investment in a joint venture, any excess of the cost of the investment over the APMC's share of the net fair value of the identifiable assets and liabilities of the investee is recognized as goodwill, which is included within the carrying amount of the investment. Any excess of the APMC's share of the net fair value of the identifiable assets and liabilities over the cost of the investment is recognized immediately in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) in the period in which the investment is acquired.

The APMC assesses whether there is objective evidence that the interest in a joint venture may be impaired. When any objective evidence exists, the investment is tested for impairment as a single asset by comparing its recoverable amount (higher of value in use and fair value less costs of disposal) with its carrying amount. Any reversal of impairment losses are recognized to the extent that the recoverable amount of the investment subsequently increases.

(c) Foreign currencies

The Commission's Annual Financial Statements are presented in Canadian dollars, which is also the functional and presentation currency of its subsidiaries. Functional currencies of the Commission's individual entities are the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates as at the balance sheet date. Foreign exchange differences arising on translation are recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rate at the date when the fair value is determined.

(d) Cash and cash equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments at the time of purchase.

(e) Prepaid expenses

Prepaid expenses relate to payments made in advance of receiving the related services and include tolls paid to NWRP in respect of turnaround costs under the Sturgeon Refinery Processing Agreement. The payments are expected to yield economic benefits over one or more future periods. Subsequent to initial recognition, prepaid expenses are recognized as

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

expenses in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss) as the services are received, or are de-recognized when it is determined there is no longer future economic benefit.

(f) Inventory

Inventory is maintained to support APMC's operations at the Sturgeon Refinery. Inventory is comprised of blended feedstock, intermediates and products. Product inventories are carried at the lower of cost and net realizable value. APMC contracts with third parties to directly deliver its share of feedstock supply to the Refinery. The cost of APMC's share of feedstock is the invoiced amount from those third parties. Net realizable value methodology for blended feedstock, intermediates and products uses a combination of weighted average index prices and actual sales prices. If the carrying amount exceeds net realizable value, a write-down is recognized.

As part of the marketing activities, oil inventory is managed on behalf of the Department of Energy ("DOE"). Inventory represents the royalty oil in feeder and trunk pipelines and consists of both purchased oil and royalty share oil. The Commission purchases oil to fulfill pipeline and quality requirements as part of the conventional crude oil marketing activities. As the Commission does not hold title to the oil and will not benefit from the ultimate sale as a principal, this inventory is not recognized.

(g) Office equipment and improvements

Office equipment and improvements are carried at cost less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use.

The Commission is depreciating its office furniture and equipment and leasehold improvements over a period of five years.

Office equipment and improvements and right-of-use assets have been presented as corporate assets in the Consolidated Statement of Financial Position.

(h) Software development assets

The Commission has internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions.

These software related assets are amortized on a straight-line basis over the estimated useful life of the software. The software systems have an estimated useful life of 10 years.

(i) Impairment of long-lived assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. In addition, an annual review is performed. Assets are grouped at the lowest level where there are separately identifiable cash inflows for the purpose of assessing impairment.

If there is an indication of impairment, the asset's recoverable amount is estimated. The recoverable amount is the greater of an asset's fair value less cost to sell and its value in use, if the carrying amount of the asset exceeds the recoverable amount, an impairment loss is recognized. Impairment losses are recognized in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

If the circumstances leading to the impairment are no longer present, an impairment loss may be reversed related to the software development assets described as intangible assets in these financial statements. The extent of the impairment loss

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

that can be reversed is determined by the carrying cost net of amortization that would have existed if the impairment had not occurred. Therefore, reversal of the loss cannot exceed the total carrying cost less amortization of the asset had the impairment not occurred. The impairment loss reversals are recognized in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

(j) ***Right-of-use assets and liabilities***

At inception of a contract, an assessment is performed to assess whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, an assessment is performed to determine whether: the contract involves the use of an identified asset; has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, has the right to direct the use of the asset.

A right-of-use asset and a lease liability is recognized at the commencement date of the lease contract, which is the date that the right-of-use asset is available. The right-of-use asset is initially measured at cost. The cost of a right-of-use asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the right-of-use asset is depreciated using the straight-line method over the earlier of the end of the useful life of the right-of-use asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Commission's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are re-measured if there are changes in the lease term or if the Commission changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also re-measured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

(k) Revenue from contracts with customers

Revenue from contracts with customers is recognized when or as APMC satisfies a performance obligation by transferring a promised good or service to a customer. For marketing activities, the Commission earns revenue through marketing fees charged to the DOE based on net volumes sold. Collection of revenue occurs on or about the 25th of the month following delivery. Marketing fees are recognized when earned which corresponds to the service period in which the conventional crude oil marketing activities take place.

The Sturgeon Refinery achieved the Commercial Operations Date (“COD”) as of June 1, 2020. Revenue from product sales is recognized when performance obligations in the sales contracts are satisfied and it is probable that the Commission will collect the consideration to which it is entitled. Performance obligations are satisfied at the point in time when the product is lifted from the Refinery facility and control passes to the customer. The customers are assessed for creditworthiness before entering into contracts and throughout the revenue recognition process. The larger contracts for the sale of products generally have terms of greater than a year. There are also spot deals and contracts less than a year. Revenues are typically collected in the current month or the following month.

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(l) Financial instruments

(i) Financial assets:

The Commission classifies its financial assets in the following categories: measured at amortized cost, fair value through other comprehensive income ("FVTOCI") and fair value through profit or loss ("FVTPL"). The classification is made at initial recognition and depends on the Commission's business model for managing financial assets and the contractual terms of the cash flows. In order for a financial asset to be classified and measured at amortized cost or FVTOCI, it needs to give rise to cash flows that are solely payments of principal and interest ("SPPI") on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level. Financial assets with cash flows that are not SPPI are classified and measured at fair value through profit or loss, irrespective of the business model.

The Commission's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both. Financial assets classified and measured at amortized cost are held within a business model with the objective to hold financial assets in order to collect contractual cash flows while financial assets classified and measured at FVTOCI are held within a business model with the objective of both holding to collect contractual cash flows and selling.

Subsequent measurement of financial instruments is based on their initial classifications. The Commission does not currently have any financial assets classified or measured at FVTOCI.

Financial assets at amortized cost:

The Commission classifies cash and cash equivalents, cash held in trust and accounts receivable as financial assets at amortized cost. Amortized cost is defined as the amount at which the financial asset is measured at initial recognition minus the principal repayments, plus or minus the cumulative amortization using the effective interest rate ("EIR") method of any difference between the initial amount and the maturity amount and, for financial assets, as adjusted for any loss allowance. Gains and losses are recognized in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss) when the asset is derecognized, modified or impaired.

Financial assets at FVTPL:

The Commission has determined that it does not have control, joint control or significant influence over its Investment in the KXL Expansion Project Class A and C Interests and this investment does not meet the SPPI test, despite the Class A Interests earning a return in the form of accretion income (note 10). Therefore, the Commission measures the Investment in KXL Expansion Project at FVTPL. Financial assets at FVTPL are carried in the Consolidated Statement of Financial Position at fair value with net changes in fair value recognized in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

Impairment:

The Commission's accounting policy for impairment of financial assets is as follows: at each reporting date, on a forward looking basis, the Commission assesses the expected losses associated with its financial assets carried at amortized cost. For trade accounts receivable, the simplified approach permitted by IFRS 9 is applied, which requires expected lifetime credit losses to be recognized from initial recognition of the receivable. To measure expected credit losses, accounts receivable are grouped based on the counterparty investment rating as reported by the credit rating agencies and an anticipated default rate is applied to each rating multiplied by the receivable balance outstanding at a reporting date. For counterparties not rated by the credit rating agencies, the simplified approach and a provision matrix will be used to calculate the impairment provision. The matrix would look at a different percentage applied against each aging category,

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including the current amounts. The internal and external credit rating of a counterparty will be considered as part of this overall process.

Credit risk for longer term receivables is assessed based on an external credit rating of the counterparty. For longer term receivables with credit risk that has not increased significantly since the date of recognition, the Commission measures the expected credit loss as the 12 month expected credit loss.

Changes in the provision for expected credit loss are recognized on the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

The Commission considers a financial asset to be in default when contractual payments are 90 days past due. However, in certain cases, the Commission may also consider a financial asset to be in default when internal or external information indicates that APMC is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

(ii) Financial liabilities:

Financial liabilities are classified, at initial recognition, as financial liabilities at FVTPL, loans and borrowings, payables, as appropriate.

All financial liabilities are recognized initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs. The Commission's financial liabilities include accounts payable, due to Department of Energy, short term and long term debt, and accrued interest payable.

For purposes of subsequent measurement, financial liabilities are classified in two categories:

- financial liabilities at FVTPL; or
- financial liabilities at amortized cost.

All of the Commission's financial liabilities are subsequently measured at amortized cost using the EIR method. Gains and losses are recognized in profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

(iii) Fair value measurement:

The Commission measures financial instruments such as the Investment in the KXL Expansion Project at fair value at each Consolidated Statement of Financial Position date.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability.

The principal or the most advantageous market must be accessible by the Commission. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

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A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Commission uses valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level input that is significant to the fair value measurement as a whole:

- Level 1 - Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
- Level 2 - Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
- Level 3 - Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

For assets and liabilities that are recognized in the Annual Financial Statements at fair value on a recurring basis, the Commission determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

The Commission determines the policies and procedures for fair value measurement. External valuation specialists may be utilized in the valuation of significant assets, such as the Investment in the KXL Expansion Project. Involvement of external valuation specialists is decided upon annually by senior management of APMC. Selection criteria include market knowledge, reputation, independence and whether professional standards are maintained. The Commission decides, after discussions with the external valuation specialists, which valuation techniques and inputs to use in the measurement of fair value.

At each reporting date, senior management reviews the values of assets and liabilities that are required to be re-measured or re-assessed as per the Commission’s accounting policies. When estimating the fair value, the Commission develops key assumptions based on objective observable data, to the extent possible, and agrees major inputs to contracts and other relevant documents.

The Commission compares the key assumptions and major input used in the determination of the fair value of each asset and liabilities to relevant external sources when available.

At each reporting period, the Commission presents the valuation results to the Board. This includes a discussion of the major assumptions used in the valuations.

For the purpose of fair value disclosures, the Commission has determined classes of assets and liabilities on the basis of the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy, as explained above.

(iv) Financial guarantee contracts:

Financial guarantee contracts are contracts issued by APMC that contingently require the Commission to make specified payments to reimburse the holder for a loss it incurs because the specified debtor fails to make payment when due in accordance with the terms of a debt instrument. The date the Commission becomes a party to the irrevocable commitment is the date of initial recognition. Financial guarantee contracts are initially recognized and measured at the fair value of the obligation undertaken in issuing the guarantee, which is generally equal to the guarantee fee received in advance (if any), adjusted for transaction costs that are directly attributable to the issuance of the guarantee. Subsequently, the guarantee is

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recognized as a liability measured at the higher of (i) the amount initially recognized (if any) less amortization for the passage of time and (ii) the loss allowance measured using an expected credit loss ("ECL") model.

ECLs with respect to financial guarantee contracts are calculated using a probability of default approach and are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Commission expects to receive in respect of entitlement to contractual recoveries or reimbursements (but excluding expected guarantee fees or premiums), discounted at an approximation of the current rate representing the risk of cash flows.

ECLs are recognized in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL). Any changes in the recognized liability is included in income. In assessing whether there has been a significant increase in the credit risk since initial recognition, the Commission considers the changes in the risk that the specified debtor will default on the contract.

(m) Provisions and onerous contracts

<u>Provisions</u>

Provisions, including contingent consideration, are recognized when the Commission has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount has been reliably estimated. Provisions are not recognized for future operating losses. Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognized as interest expense.

<u>Onerous contracts</u>

At each year-end, APMC performs an onerous contract assessment. A provision for an onerous contract is recorded when the unavoidable costs of meeting an obligation under a contract exceed the economic benefits expected to be received under it. APMC uses an incremental cost approach to determine the costs of fulfilling obligations under a contract. Where a provision is required, it is measured as the net present value of the unavoidable net cash flows, and is recorded as an expense on the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss) and offsetting liability on the Consolidated Statement of Financial Position.

For each subsequent year-end, the Commission will perform an assessment to determine if the contract remains onerous, and if so, update the provision accordingly.

The balance sheet provision will be adjusted each year to the new net present value (either higher or lower) with the offset being recorded through the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). If the contract is no longer onerous, then the provision is reversed in its entirety (i.e. the contract cannot become an asset).

(n) Finance income and finance expenses

Finance income generated from conventional crude oil marketing operations comprises interest income earned on cash and cash equivalents.

Finance income related to the Sturgeon Refinery is comprised of interest income earned on the term loan receivable and interest income earned daily on cash and cash equivalents.

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Finance expenses consist of interest expense on debt obligations, net of the unwinding of premiums recognized on the issuance of debt, and accretion expense on Surgeon Refinery Processing Agreement provision.

(o) Income taxes

As stated in Note 1 above, the Commission is exempted from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd., a Delaware incorporated company and 2254746 Alberta Ltd., an Alberta incorporated company have exposure to US federal and state corporate income taxes.

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the country in which the Commission generates taxable income.

Current income tax relating to items recognized directly in equity is recognized in equity and not in profit or loss. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax is accounted for using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying value for financial reporting purposes as at the reporting date.

Deferred tax assets are recognized for all deductible temporary differences, the carry forward of unused tax credits, and any unused tax losses. Deferred tax assets are recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences, the carry forward of unused tax credits, or the unused tax losses can be utilized.

Deferred tax is not recognized for:

- Temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither the accounting nor taxable profit or loss;
- Taxable temporary differences arising on the initial recognition of goodwill; and
- Temporary differences related to investments in subsidiaries and joint ventures to the extent that is probable that they will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that taxable income will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred tax asset to be recovered.

Deferred tax liabilities are recorded for all temporary differences other than where the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

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4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of these Annual Financial Statements in conformity with IFRS requires the Commission to make judgements, estimates and assumptions that affect the reported amounts of assets, liabilities, and the disclosure of contractual obligations and contingencies, if any, at the date of the Annual Financial Statements and reported amounts of revenues and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the Annual Financial Statements. Estimates and judgements are continuously evaluated and based on the Commission's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future period affected.

The following are judgements, estimates and assumptions that the Commission has made in the process of applying APMC's accounting policies and that have the most significant effect on the amounts recognized in these Annual Financial Statements.

(a) Government business enterprise

Under public sector accounting standards, organizations which are controlled by the government are either government business enterprises or other government organizations. Government business enterprises are required to apply IFRS, whereas other government organizations are provided with a choice for basis of presentation. The Commission has exercised judgment and determined that it is a government business enterprise because it is a separate legal entity and has been delegated financial and operational authority to carry on a business. In 2013, the Commission's mandate was expanded, and it is expected through its involvement with other marketing activities, such as the Sturgeon Refinery that it can provide services, maintain its operations and meet liabilities from sources outside of the government reporting entity. Had the Commission not been determined to be a government business enterprise, the Commission would have continued to apply public sector accounting standards, and such an alternative basis of accounting could have a pervasive effect on the measurement and presentation of items in the Annual Financial Statements.

(b) Revenue recognition

The Commission has exercised judgment in determining whether it is acting as a principal or agent with respect to conventional crude oil marketing activities. The Commission is providing services to the Crown as delegated in the Petroleum Marketing Act that are "…in the public interest of Alberta". The Commission accepts delivery of and markets the Crown's royalty share of crude oil, and has the ability to determine which customers to transact with, and whether it should purchase additional product for blending activities to change the composition of crude oil sold. Under the *Petroleum Marketing Act,* the Commission has the responsibility for ensuring the crude oil meets the customers' specifications and for the establishment of prices. However, the Commission does not have the ability to direct the use of the crude oil, as the use is mandated by the Crown via the *Petroleum Marketing Act*. The Commission remits the net proceeds from the sale of product to the DOE, and therefore does not have the ability to obtain the benefits from the crude oil. As the APMC does not direct the use of the crude oil, nor obtain the economic benefits from it, management has determined that it does not have control and is therefore an agent with respect to the conventional crude oil marketing activities. Therefore, the gross inflows and economic benefits of conventional crude oil marketing activities are considered collected on behalf of the DOE and are not recognized as revenue.

APMC has used judgment in determining whether it is acting as a principal or agent with respect to crude-by-rail activities. APMC was directed, on May 24, 2019, "…take all steps possible to explore best options for assigning crude-by-rail program contracts entered into by the Commission to third parties, and to enter into assignment agreements as expeditiously as possible with third parties on commercial terms, provided that the final terms have been approved by the Government". While the Commission entered into the contracts, it was acting as agent on behalf of the Crown and all financial risk belongs to the Crown. Therefore, the gross inflows and economic benefits of the crude-by-rail program are considered collected on

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behalf of the Crown and are not recognized as revenue. All of the remaining crude-by-rail program contracts were successfully divested by APMC on behalf of the Crown as of March 31, 2022.

APMC has also exercised judgment in determining whether it is acting as a principal or agent with respect to Sturgeon Refinery Tollpayer activities. As part of the processing agreement, NWRP processes the feedstock provided by APMC and CNRL (collectively, the “Tollpayers”) into refined products and will sell the refined products and by-products on behalf of APMC and CNRL. APMC and CNRL take the financial responsibility for the refined products and by-products meeting customer specifications, inventory risk, and establishing prices for the products. Therefore, APMC is acting as the principal in this arrangement and the gross inflows and economic benefits of the Sturgeon Refinery activities are recognized as revenue.

(c) Interests in Sturgeon Refinery

Prior to closing of the Optimization Transaction on June 30, 2021 (note 12), APMC’s interest in the Sturgeon Refinery was as follows:

NWRP was a general partnership formed by CNR (Redwater) Limited (formerly Canadian Natural Upgrading Limited) ("CNR Redwater"), a wholly-owned subsidiary of CNRL and by NWU LP, an indirect wholly-owned subsidiary of North West Refining Inc. NWRP was formed under the Partnership Act (Alberta) pursuant to a partnership agreement dated February 15, 2011, as amended on November 7, 2012, March 11, 2013 and April 7, 2014. The partners each had a 50 percent partnership interest in NWRP.

NWRP had entered into various agreements to construct and operate the Sturgeon Refinery, a facility 45 kilometres north-east of Edmonton which has the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an incurred facility capital cost (“FCC”) of $10.0 billion. APMC is providing the Sturgeon Refinery with 37,500 bbl/d of bitumen feedstock and Canadian Natural Resources Partnership will provide the remaining 12,500 bbl/d of bitumen feedstock under a former 30 year cost-for-service tolling agreements (collectively, the Processing Agreements). The Sturgeon Refinery achieved its COD on June 1, 2020.

Effective with the completion of the Optimization Transaction for the Sturgeon Refinery, as disclosed in note 12, APMC now owns a 50 percent partnership interest in NWRP. APMC has exercised judgement in determining that it has joint control over NWRP and that the joint arrangement is a joint venture. This determination was based upon the assessment that APMC and CNRL, under the terms of the existing Processing Agreements, are currently not expected to purchase substantially all of the economic output of the Sturgeon Refinery (i.e. refinery services) as compared to the estimated life of the Sturgeon Refinery.

APMC had entered into a term loan with NWRP which earned interest at a rate of prime plus six percent, compounded monthly, and was to be repaid over 10 years starting one year after COD. While the loan to NWRP was outstanding, APMC was entitled to a 25 percent voting interest on the Executive Leadership Committee ("ELC"), which is charged with overseeing and making decisions on the operations of the Sturgeon Refinery. CNRL and North West Refining Inc. had 50 percent and 25 percent voting interests on the ELC, respectively.

Pursuant to the Processing Agreements, NWRP processes bitumen and sells the refined products on behalf of the Tollpayers. As required by the terms of the Processing Agreements, a trust account (the "Initial Proceeds Trust Account" or "IPTA") has been established to facilitate the payments to and from the Tollpayers and NWRP. APMC has exercised judgment in determining that IPTA, on behalf of the Tollpayers, is a joint operation in which the Commission has a 75 percent interest in the assets, liabilities, revenue and expenses.

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(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate its' toll commitments pursuant to the Processing Agreement included in note 21 Commitments. The toll has both a debt component and a monthly operating component. To estimate the future toll, management has used estimates for factors including future interest rates, operating costs, oil prices (West Texas Intermediate ("WTI")) and light/heavy differentials), refined product prices, gas prices and foreign exchange rates.

(e) Sturgeon Refinery Processing Agreement assessment

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

Technical inputs may be estimated with reasonable accuracy for a particular operating plan; however revenues and costs that depend upon market prices are challenging to estimate, particularly over long future time periods. The amended Processing Agreement has a term of 40 years and may be renewed for successive five year periods at APMC’s option. In order to perform the onerous contract analysis, APMC management developed estimates for the key variables based primarily on GOA forecasts.

(f) Contingent consideration

In connection with the Optimization Transaction (note 12), NWRP entered into an agreement with NWU LP to utilize certain CO2 capture technology in exchange for an annual licensing fee based on CO2 captured from the Refinery, resulting in the recognition of a fair value provision for contingent consideration relating to APMC's acquisition of a partnership interest in NWRP.

The Commission uses a cash flow model to determine the fair value of the contingent consideration. The model uses a number of variables to calculate the cash outflows for APMC. Those variables include estimates and technical variables that arise from the design of the project such as the forecast of annual CO2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100, an assumption that the annual licensing fee will meet the economic tests in future periods and the calculation of a credit adjusted risk free discount rate.

Technical inputs for annual CO2 licensing fee may be adjusted in future periods based upon the operating performance of the Sturgeon Refinery.

(g) ***Interests in other entities***

APMC applies judgement in determining the classification of its interest in other entities, such as: (i) the determination of the level of control or significant influence held by the Commission; (ii) the legal structure and contractual terms of the arrangement; (iii) concluding whether the Commission has rights to assets and liabilities or to net assets of the arrangement; and (iv) when relevant, other facts and circumstances. The Commission has determined that the Investment in the KXL Expansion Project is a financial asset measured at fair value through profit or loss as described in IFRS 9 *Financial Instruments*.

(h) Fair value measurement of financial instruments

When the fair values of financial assets recorded in the Consolidated Statement of Financial Position cannot be measured based on quoted prices in active markets, their fair value is measured using valuation techniques.

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The Commission has estimated the fair value of the KXL Investment at March 31, 2023 and 2022 using a probability-weighted valuation technique. The fair value of the KXL Investment is included in Level 3 of the fair value hierarchy (note 10 and 20) because it requires the use of significant unobservable assumptions in the valuation techniques used to determine the fair value estimate. The determination of the fair value of the KXL Investment is complex and relies on several critical judgements and estimates. These critical assumptions and estimates used in determining the fair value of the KXL Investment are: the identification of potential scenarios that would impact the amount and timing of cash flows relating to the KXL Investment, the expected probability of those outcomes, and the estimated cash inflows and outflows relating to potential outcomes. Fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in assumptions could affect the reported fair value of the financial instrument. Assumptions used in the determination of the fair value of the KXL Investment will continue to be refined as outcomes become known and more information becomes available.

(i) Right-of-use assets

Purchase, extension and termination options are included in certain lease agreements to provide operational flexibility. To measure the lease liability, judgment is used to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. Estimates are also used to determine its incremental borrowing rate if the interest rate implicit in the contract is not readily determinable.

(j) Operating segments

The Commission has reviewed and determined its operating segments as disclosed in note 30.

5. NEW ACCOUNTING POLICIES

Amendments to IAS 16 Property, Plant and Equipment

On April 1, 2022, APMC adopted Property, Plant and Equipment - Proceeds before Intended Use issued by the IASB which made amendments to *IAS 16 Property, Plant and Equipment* ("IAS 16"). The amendments prohibit a company from deducting from the cost of property, plant, and equipment ("PP&E") amounts received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related cost in profit or loss. The adoption of the amendments to IAS 16 did not have a material impact to APMC's financial statements.

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On April 1, 2022, APMC adopted Onerous Contracts - Cost of Fulfilling a Contract issued by the IASB which made amendments to *IAS 37 Provisions, Contingent Liabilities and Contingent Assets* ("IAS 37"). The amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous. The adoption of the amendments to IAS 37 did not have a material impact to APMC's financial statements.

Amendments to IAS 1: Classification of Liabilities as Current or Non-current

In January 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classifying liabilities as current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period.

The amendments are effective for annual reporting periods beginning on or after January 1, 2023 and with early adoption permitted. These amendments must be applied retrospectively. The Commission is currently assessing the impact the amendments will have on current practice.

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Amendments to IAS 8: Definition of Accounting Estimates

In February 2021, the IASB published amendments to IAS 8 to help entities distinguish between accounting policies and accounting estimates. Under the new definition, accounting estimates are monetary amounts in financial statements that are subject to measurement uncertainty.

The definition of a change in accounting estimates was deleted. However, the IASB retained the concept of changes in accounting estimates in the standard with the following clarifications:
• A change in accounting estimate that results from new information or new developments is not the correction of an error
• The effects of a change in an input or a measurement technique used to develop an accounting estimate are changes in accounting estimates if they do not result from the correction of prior period errors

The amendments are effective for annual reporting periods beginning on or after January 1, 2023 and changes in accounting policies and changes in accounting estimates that occur on or after the start of that period. Early adoption is permitted. The Commission is currently assessing the impact the amendments will have on current practice.

6. CASH AND CASH EQUIVALENTS

Cash and cash equivalents as at March 31, 2023 was $45.3 million (March 31, 2022 - $26.7 million). Cash and cash equivalents consist of deposits in the Consolidated Liquidity Solution (the “Fund”) which is a cash pooling structure managed by Treasury Board & Finance ("TB&F") to provide competitive interest income while maintaining appropriate security and liquidity of depositors’ capital. For the year ended March 31, 2023, the Commission earned $0.6 million (year ended March 31, 2022 - $0.2 million).

7. RESTRICTED CASH

Restricted cash, including cash and cash equivalents, as at March 31, 2023 was $76.6 million (March 31, 2022 – $72.6 million) and relates to the Sturgeon Refinery. It is restricted and held on behalf of the Sturgeon Refinery Tollpayers, namely APMC and CNRL. The amount reported is the 75 percent portion attributable to APMC as a Tollpayer. The Commission does not have immediate access to the cash held in the trust account. The cash is to be used for funding the Sturgeon Refinery processing operations and for paying all tolls. Any cash distributions will be in accordance with the Processing Agreement.

Excess trust account funds at the Sturgeon Refinery are invested in low-risk, liquid short-term investments, with no longer than a 90 day term to maturity. For the year ended March 31, 2023, the short-term investments earned $1.2 million (year ended March 31, 2022 - $nil).

8. ACCOUNTS RECEIVABLE

($000s)	Note	**March 31, 2023**	March 31, 2022
Accounts receivable		**481,450**	656,993
Credit loss provision	20	**(18,012)**	(952)
Balance, end of year		**463,438**	656,041

Accounts receivable is comprised of receivables from crude oil royalty marketing transaction activities on behalf of the Province and receivables from Sturgeon Refinery product sales.

As at March 31, 2023, there was $183.9 million (March 31, 2022 – $209.8 million) of accounts receivable for marketing transaction activities primarily for the March 2023 delivery month, which was settled in cash on April 25, 2023. In addition,

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there was $279.5 million (March 31, 2022 – $446.3 million) of account receivable related to the Sturgeon Refinery which consisted primarily of the sale of refined products delivered in March 2023. The terms related to the sale of refined products are not greater than net 21 days.

9. INVENTORY

($000s)	**March 31, 2023**	March 31, 2022
Current		
Balance, beginning of year	**95,704**	51,711
Additions	**1,859,051**	1,803,746
Cost of sales	**(1,884,148)**	(1,759,753)
Balance, end of year – current portion	**70,607**	95,704
Long term		
Balance, beginning of year	**6,877**	6,877
Additions	**—**	—
Balance, end of year – long-term portion	**6,877**	6,877

As at March 31, 2023 there was $70.6 million (March 31, 2022 - $95.7 million) of hydrocarbon inventory classified as current as the Commission expects to sell it within the next twelve months of the financial reporting period. Product inventory is comprised of synthetic crude oil, intermediate products, ultra-low sulphur diesel, unconverted oil, diluent and sulphur.

As at March 31, 2023 there was $6.9 million (March 31, 2022 - $6.9 million) of long term inventory consisting of line fill and tank bottoms. The Commission does not anticipate to sell these volumes within the next 12 months.

10. INVESTMENT IN KXL EXPANSION PROJECT

On June 9, 2021, the APMC, as directed by the Alberta Government entered into the Final KXL Agreement (“the Final KXL Agreement”) with TC Energy for an orderly exit from the KXL project and partnership. APMC provided total contributions of CAD$1.035 billion on behalf of the TCPL partnerships to fund debt guarantee cancellation payments to the lenders as part of the original investment agreement.

The debt guarantee cancellation payments were paid on June 16, 2021 and the APMC has no further obligations relating to the Investment Agreement and/or the debt guarantee. In exchange for APMC making the guarantee cancellation payments through its wholly owned Canadian and US subsidiaries, Class C Interests were received from the TCPL partnerships. The Class C Interests received on June 16, 2021 do not have any put rights, voting rights or approval rights with respect to the business and affairs of the TCPL partnerships or carriers. Class A Interests were redeemed for a nominal amount on June 16, 2021. The Final KXL Agreement also provides a mechanism for future distribution of proceeds from liquidated assets of the KXL project to APMC, for its Class C interests, and to TCPL. Upon the completion of the liquidation of the KXL assets and the distribution of the gross proceeds thereof, the Final KXL Agreement also provides that all Canadian and US Class C Interests held by APMC subsidiaries shall redeemed for nominal consideration. APMC has reflected the terms of the Final KXL Agreement in determining its fair value estimates for the Investment in the KXL Expansion Project and the KXL Expansion Project Debt Guarantee in the consolidated financial statements as at March 31, 2023 and March 31, 2022. For the year ended March 31, 2023, the Commission has incurred a gain of $9.1 million (March 31, 2022: $10.5 million gain) on the estimated fair value of its Investment in the KXL Expansion Project.

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A reconciliation of the change in the KXL Expansion Project investment is as follows:

($000s)	**March 31, 2023**	March 31, 2022
Balance, beginning of year	**82,000**	106,000
Liquidation proceeds on Class C interests	**(63,770)**	(37,795)
Foreign exchange	**5,716**	3,324
Net change in fair value	**9,054**	10,471
Balance, end of year	**33,000**	82,000

The fair value of the KXL Investment as at March 31, 2023 and 2022 was estimated using a market approach to value Keystone XL Phase 4 pipeline assets under an abandonment scenario incorporating inputs for the estimated realizable value of the assets.

The determination of the fair value estimate included significant unobservable inputs (fair value measurement hierarchy – level 3): estimated cash inflows and outflows relating to an abandonment scenario. If the estimated cash flows relating to the abandonment scenario increase (decrease), the fair value estimate increases (decreases).

As the liquidation process under the abandonment scenario continues, more information is likely to become available that will impact the significant unobservable inputs used in the determination of the estimated fair value of the KXL assets. As a result, the estimated fair value will be impacted by events after the reporting period.

On February 9, 2022, the APMC, on behalf of the GOA, filed a Notice of Intent as a formal step to initiate a legacy North American Free Trade Agreement ("NAFTA") claim over the cancellation of the presidential permit for the Keystone XL pipeline. On April 27, 2023, the APMC, on behalf of the GOA, filed a Notice of Arbitration to initiate its arbitration claim against the United States of America under the Canada-United States-Mexico Agreement and the NAFTA. The Notice of Arbitration initiated an arbitration claim to seek recovery for approximately CAD $1.3 billion of the Alberta government's investment in KXL.

11. INTANGIBLE ASSETS

($000s)	**March 31, 2023**	March 31, 2022
Cost:		
Balance, beginning and end of year	**10,644**	10,644
Accumulated depreciation and amortization:		
Balance, beginning of year	**(2,927)**	(1,863)
Depreciation and amortization	**(1,065)**	(1,064)
Balance, end of year	**(3,992)**	(2,927)
Net book value, end of year	**6,652**	7,717

The Commission internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions. Both systems became operational in 2019. The intangible assets are amortized on a straight-line basis over the estimated useful life of the software of 10 years. The Commission has completed its review of intangible assets and determined there is no impairment.

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12. INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

On June 30, 2021, the Alberta Petroleum Marketing Commission and certain of its subsidiaries (collectively, "APMC") negotiated a series of agreements (collectively, the "Agreements") through which APMC would purchase a limited partnership interest in NWRP, (the "Optimization Transaction"). Pursuant to the Agreements, APMC purchased the limited partnership interest from NWU LP, a company owned by North West Refining Inc. (Alberta). To effect this purchase, APMC acquired two newly formed subsidiaries of NWU LP (as later renamed to APMC (Redwater) L.P., and its general partner APMC (Redwater) Corp.) holding the interest in NWRP. Following the purchase of the limited partnership interest, APMC holds a 50 percent interest in NWRP. The other 50 percent interest holder in NWRP is CNR Redwater.

The acquisition enables APMC to provide oversight and governance of the Refinery operations, maintenance, technical engineering, economic planning and scheduling, and optimization. To facilitate this oversight function, the APMC participates in the following committees: executive leadership, finance and insurance, commercial marketing, and audit. The CFO of APMC is the current chair of the audit committee.

As per the Partnership Interest Purchase Agreement, the contractual purchase price for the transaction was one Canadian dollar payable upon closing.

Also, in connection with the Optimization Transaction, NWRP entered into an agreement with NWU LP to utilize certain CO2 capture technology in exchange for an annual licensing fee based on CO2 captured from the Refinery. The licensing fee is payable at a rate of approximately $7.00/tonne of CO2 captured and transported in the Alberta Carbon Trunk Line ("ACTL"), with the first payment occurring in March 2022 for CO2 captured during the calendar years of 2020 and 2021. The licensing fee structure includes annual contractual escalation adjustments. Subsequent to the first payment, the annual licensing fee payable in future periods will be subject to reductions based on certain economic tests. As at June 30, 2021, APMC recognized the fair value of its share of amounts expected to be payable in future periods for the licensing fee as contingent consideration of $217.3 million.

The fair value estimate of the contingent consideration was calculated based upon the following: 1) management's forecast of annual CO2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100; 2) an assumption that the annual licensing fee payable will meet the economic tests in future periods; and 3) the calculation of a net present value of the expected license fee payments as discounted using a credit adjusted risk free rate of 3.35 percent. As at June 30, 2021, management performed a sensitivity analysis on the forecast annual CO2 volumes captured and the credit adjusted risk free discount rate estimates. If the forecast annual CO2 volumes captured were decreased by 5 percent or the discount rate was increased by 50 basis points, the contingent consideration would decrease by $10.7 million and $31.8 million, respectively.

APMC assessed the acquisition of the partnership interest in NWRP to be a joint venture and has accounted for the arrangement using the equity method of accounting in accordance with *IAS 28 Investments in Associates and Joint Ventures*. The cost of the investment comprises the purchase price and any directly attributable expenditures to obtain it. Accordingly, APMC has capitalized $56.3 million of transaction costs for legal and advisory consulting services to the cost of the investment. In addition, for the year ended March 31, 2022, $1.2 million of advisory consulting services related to the Optimization Transactions, but determined not to be directly attributable to the purchase, has been recorded to consulting in general and administrative expenses.

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The table below summarizes the purchase equation and allocation of fair value of the investment in NWRP acquired on the closing date of June 30, 2021:

($000s)	**Consideration**
Cash consideration of one dollar	-
Contingent consideration – license fee	**217,251**
	217,251
Transaction costs attributable to acquiring partnership interest	**56,235**
	273,486

($000s)	**Cost of Investment**
Share of fair value of net identifiable assets and liabilities	**(372,026)**
Goodwill on investment in NWRP	**645,512**
Cost of investment in NWRP	**273,486**

The determination of the share of fair value of net identifiable assets and liabilities as made by management at the time of the preparation of these financial statements was based on information then available. External valuation specialists were engaged to assist in the valuation of the fair value of identifiable assets and liabilities of NWRP. APMC decides, after discussions with the external valuation specialists, which valuation techniques and inputs to use in the measurement of fair value.

Under the Optimization Transaction, the original term of the Processing Agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6 percent, with lower cost senior secured bonds at an average rate of approximately 2.56 percent, reducing interest costs to NWRP and associated tolls to the Tollpayers. As such, on June 30, 2021, NWRP repaid APMC's and CNRL's subordinated debt advances, resulting in $553.8 million of principal and interest repaid on the term loan receivable to APMC. In addition, $840 million was distributed by NWRP to CNRL and NWU LP prior to the Optimization closing.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20 percent series L senior secured bonds due December 2023, $500 million of 2.00 percent series M senior secured bonds due December 2026, $1,000 million of 2.80 percent series N senior secured bonds due June 2031, and $600 million of 3.75 percent series O bonds due June 2051. Additionally, NWRP's existing $3.5 billion syndicated credit facility was amended. The $2.0 billion revolving credit facility was extended by three years to June 2024, and the $1.5 billion non-revolving credit facility was reduced by $0.5 billion to $1.0 billion and extended by two years to June 2023.

As a result of the Optimization Transaction, the APMC is a 50 percent owner in NWRP, in addition to being a 75 percent Tollpayer in the Sturgeon Refinery.

The Commission remains unconditionally obligated to pay to NWRP its 75 percent pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. The Commission's estimated commitments for the monthly toll comprised of debt and operating components include the operating and financial commitments of NWRP.

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The gain from North West Redwater Partnership consists of the following:

	Years ended March 31,	
($000s)	**2023**	2022
APMC's share of loss from the investment in NWRP	**(20,277)**	(22,885)
Adjustments to NWRP license fee provision (note 18)	**117,638**	25,496
Gain from North West Redwater Partnership	**97,361**	2,611

Summarized financial information of the joint venture, based on its IFRS financial statements, and reconciliation with the carrying amount of the investment is as follows:

($000s)	**March 31, 2023**	March 31, 2022
Current assets, including cash and cash equivalents of $nil (March 31, 2022 - $25,696)	**292,718**	229,974
Non-current assets	**11,226,974**	11,396,291
Short term borrowings	**(64,366)**	(24,000)
Other current liabilities [1]	**(804,747)**	(276,808)
Long term debt [2]	**(10,473,454)**	(11,252,894)
Other non-current liabilities	**(1,007,501)**	(862,385)
Deficit - 100%	**(830,376)**	(789,822)
APMC's share - 50%	**(415,188)**	(394,911)
Goodwill	**645,512**	645,512
APMC's carrying amount of the investment	**230,324**	250,601

1. As at March 31, 2023, other current liabilities including bank indebtedness of $103 million (March 31, 2022 - $nil). One of the senior secured notes Series L of $500 million will mature on December 1, 2023 and $60 million of credit facility is due June 25, 2023. These amounts have been included in other current liabilities.
2. As at March 31, 2023, long term debt of NWRP consisted of senior secured notes of $8.3 billion and $2.2 billion outstanding under the credit facility (year ended March 31, 2022 - $8.8 billion and $2.4 billion, respectively). As at March 31, 2023, the weighted average interest rate on all senior secured notes amounts outstanding was 3.40 percent (year ended March 31, 2022 - 3.32 percent).

Summarized statement of income (loss) of NWRP:

	Years ended March 31,	
($000s)	**2023**	2022
Revenue from Tollpayers [1]	**1,206,330**	757,631
Net income and comprehensive income for the year [2]	**(40,554)**	(45,769)
APMC's share of net income (loss) for the year	**(20,277)**	(22,885)

1. Included in NWRP's revenue for the year ended March 31, 2023 is $905 million paid by the Commission for its 75 percent share of the refining toll (year ended March 31, 2022 - $568 million).
2. Included in the net income (loss) for the year ended March 31, 2023 is the impact of depreciation and amortization expense of $304.2 million (year ended March 31, 2022 - $245.0 million), asset derecognition expense of $35.9 million (year ended March 31, 2022 - $nil) and finance costs of $355.7 million (year ended March 31, 2022 - $226 million).

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13. ACCOUNTS PAYABLE

($000s)	**March 31, 2023**	March 31, 2022
Trade payables	**123,159**	118,179
Accrued liabilities	**265,950**	430,131
Balance, end of year	**389,109**	548,310

Accounts payable and accrued liabilities are comprised of payables from marketing transactions and from Sturgeon Refinery activities.

As at March 31, 2023, there was $26.4 million (March 31, 2022 – $28.9 million) of payables for marketing activities primarily for the March 2023 delivery month, which were cash settled on April 25, 2023, as well as for general and administrative expenses.

In addition, there was $362.7 million (March 31, 2022 – $519.4 million) of account payable and accrued liabilities related to Sturgeon Refinery activities consisting of purchase of Refinery feedstock, and processor tolls for the March 2023 delivery month. The purchases of Refinery feedstock are settled on April 25, 2023. The processor tolls and Optimization Transactions are net settled against refined product sales proceeds on April 25, 2023.

14. DUE TO THE DEPARTMENT OF ENERGY

($000s)	**March 31, 2023**	March 31, 2022
Balance, beginning of year	**218,949**	58,642
Amount to be transferred	**2,821,783**	1,363,271
Amount remitted	**(2,829,373)**	(1,202,964)
Balance, end of year	**211,359**	218,949

The Commission acts as agent of the DOE of the GOA in accepting delivery and dealing with the Crown's royalty share of hydrocarbons. The Commission remits crude oil royalty-in-kind net revenue to the DOE on a monthly basis.

15. SHORT TERM DEBT

	TB&F borrowings		
($000s)	**Sturgeon Refinery**	**KXL Expansion Project**	**Total**
Balance, March 31, 2021	1,308,572	588,067	1,896,639
Draws	1,416,990	1,070,166	2,487,156
Exchanged short term debt for long term debt bond	—	(435,353)	(435,353)
Repayments	(1,671,030)	(245,985)	(1,917,015)
Balance, March 31, 2022	**1,054,532**	**976,895**	**2,031,427**
Draws	**2,161,464**	**330,742**	**2,492,206**
Exchanged short term debt for long term bond	**(668,120)**	**(299,297)**	**(967,417)**
Repayments	**(1,955,644)**	**(359,913)**	**(2,315,557)**
Balance, March 31, 2023	**592,232**	**648,427**	**1,240,659**

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T*reasury Board & Finance ("TB&F") short term borrowings*

The Commission entered into a Lending and Borrowing Agreement ("Agreement") with the GOA effective April 1, 2014, and subsequently amended April 1, 2023. The Agreement provides the framework under which APMC may from time to time request the GOA lend money to the APMC. The GOA and APMC must obtain an Order in Council (approved by the Lieutenant Governor in Council) to authorize the lending and borrowing dollar limits. TB&F is the government unit responsible for lending on behalf of the GOA.

On November 14, 2022, the APMC converted $368.8 million of the outstanding short term debt owing for the Sturgeon Refinery into a 30 year bond. The face value of the bond is $500 million, a coupon rate of 2.95 percent and matures June 1, 2052. On July 5, 2022, the APMC converted $299.3 million of the outstanding short term debt owing for each of the Sturgeon Refinery and KXL Expansion Project ($600 million converted in total) into 11 year bonds. Each bond has a face value of $300 million, a coupon rate of 4.15 percent and matures June 1, 2033. On July 16, 2021, the Commission exchanged $435.4 million of short term debt related to the KXL Expansion Project for a 3 year bond with a coupon rate of 3.1 percent maturing on June 1, 2024. The bond was issued at a premium with $408.0 million due on maturity.

The Commission has an Order in Council that allows it to borrow up to $1.8 billion for funding related to the Sturgeon Refinery. As at March 31, 2023, the Commission has $592.2 million (March 31, 2022 - $1,054.5 million) outstanding at various interest rates, with tranches of borrowing repayable over various terms not exceeding one year. In addition, at March 31, 2023, there is $661.6 million of long term bonds outstanding on the Sturgeon Refinery. The Commission draws on its Sturgeon Order in Council monthly, to temporarily fund the Crown's purchase of feedstock. Cash received from the Sturgeon Refinery at the end of the month is used to repay borrowings. As of March 31, 2023, the undrawn amount on the Order in Council was $407.8 million (March 31, 2022 - $745.5 million).

The Commission has an Order in Council that allows it to borrow up to $2.0 billion for the Investment of the KXL Expansion Project. As at March 31, 2023, $648.4 million (March 31, 2022 - $976.9 million) was outstanding at various interest rates, with tranches of borrowing repayable over various terms not exceeding one year. In addition, at March 31, 2023, there was $716.8 million of long term bonds outstanding on the KXL Expansion Project. As of March 31, 2023, the undrawn amount on the Order in Council was $643.6 million (March 31, 2022. - $615.1 million).

The weighted average interest rate for the year ended March 31, 2023 was 3.5 percent (year ended March 31, 2022 - 0.3 percent).

16. ACCRUED INTEREST PAYABLE

($000s)	**March 31, 2023**	March 31, 2022
Accrued interest on TB&F short term debt	**10,062**	3,350
Accrued interest on TB&F long term debt	**17,421**	4,204
Balance, end of year	**27,483**	7,554

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17. LONG TERM DEBT

($000s)	Sturgeon Refinery	KXL Expansion Project	Total
Balance, March 31, 2021	—	—	—
Exchanged short term debt for long term debt bond	—	435,353	435,353
Amortization of premium on long term debt	—	(7,860)	(7,860)
Balance, March 31, 2022	**—**	**427,493**	**427,493**
Exchanged short term debt for long term debt bond	**668,120**	**299,297**	**967,417**
Amortization of premium on long term debt	**(6,496)**	**(10,022)**	**(16,518)**
Balance, March 31, 2023	**661,624**	**716,768**	**1,378,392**

On November 14, 2022, the APMC converted $368.8 million of the outstanding short term debt owing for the Sturgeon Refinery into a 30 year bond issued. The face value of the bond is $500 million, a coupon rate of 2.95 percent and matures June 1, 2052. On July 5, 2022, the APMC converted $299.3 million of the outstanding short term debt owing for each of the Sturgeon Refinery and KXL Expansion Project ($600 million converted in total) into 11 year bonds. Each bond has a face value of $300 million, a coupon rate of 4.15 percent and matures June 1, 2033. On July 16, 2021, the Commission exchanged $435.4 million of short term debt related to the KXL Expansion Project with TB&F for a 3 year bond with a coupon rate of 3.1 percent maturing on June 1, 2024. The bond was issued at a premium with $408.0 million due on maturity.

	Issue Date	Maturity Date	Coupon	Face value ($000s)
Sturgeon Refinery				
	July 5, 2022	June 1, 2033	4.15 percent	$300,000
	November 14, 2022	June 1, 2052	2.95 percent	$500,000
KXL Expansion Project				
	July 5, 2022	June 1, 2033	4.15 percent	$300,000
	July 16, 2021	June 1, 2024	3.10 percent	$408,000

18. LICENSE FEE PROVISION

($000s)	March 31, 2023	March 31, 2022
Balance, beginning of year	**197,218**	—
Contingent consideration for acquisition of partnership interest	**—**	217,251
Accretion expense	**7,420**	5,463
Change in estimate - share of license fee expense recognized in the Partnership	**(1,286)**	(2,069)
- discount rate and timing	**(116,352)**	(23,427)
	87,000	197,218
Less: current portion	**—**	(3,590)
Balance, end of year	**87,000**	193,628

In connection with the Optimization Transaction (note 12), NWRP entered into an agreement with NWU LP to utilize certain CO2 capture technology in exchange for an annual licensing fee based on CO2 captured from the Refinery, resulting in the recognition of a $217.3 million provision for license fee contingent consideration relating to APMC's acquisition of a partnership interest in NWRP.

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The fair value estimate of the contingent consideration was calculated based upon the following: 1) management's forecast of annual CO2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100; 2) an assumption that the annual licensing fee will meet the economic tests in certain future periods; and 3) the calculation of a net present value of the license fee payments are discounted using a credit adjusted risk free rate of 3.35 percent upon initial recognition of the provision and a credit adjusted risk free rate of 5.78 percent as at March 31, 2023 (March 31, 2022 – 3.75 percent).

19. STURGEON REFINERY PROCESSING AGREEMENT PROVISION

As at March 31, 2023, APMC assessed the Sturgeon Refinery Processing Agreement to determine if it represents an onerous contract. APMC uses a cash flow model to assess if the unavoidable costs related to the Processing Agreement with NWRP exceed the economic benefits to be received. The contract was determined to be onerous and APMC has recognized a provision which is calculated as the net present value of revenues from the sales of refined products less feedstock costs and the Refinery tolls charged by NWRP under the Processing Agreement, as well as the net present value of expected net benefit to be realized by APMC pursuant to the Processing Agreement as a result of its newly acquired 50 percent partnership interest in NWRP.

As a result of the Optimization Transaction on June 30, 2021, certain components of the Refinery tolls have been eliminated. In addition, the interest rate on NWRP’s term debt was renegotiated, reducing the debt components of the Refinery toll. Commodity price forecasts have improved relative to March 31, 2021, increasing the net economic benefits expected to be received. The expected net economic benefits have also increased as result of the cash flows which APMC will realize from the Processing Agreement as a 50 percent joint venture owner in NWRP. As a result, a $2.2 billion recovery adjustment in the loss provision was recorded in the year ended March 31, 2022.

The Commission recorded a $289.3 million adjustment to the loss provision as at March 31, 2023. The increase in the onerous contract provision was primarily driven by increases in forecast interest rates arising from inflationary global economic concerns.

The undiscounted future cash net inflows are estimated to be $13.4 billion over the expected life of the project. The provision has been recognized by discounting these cash flows using a discount rate of 8.5 percent. The onerous contract provision is expected to be settled in periods up to May 2083.

During the years ended March 31, 2023 and 2022, the movement in the Sturgeon Refinery Processing Agreement provision is as follows.

($000s)	**March 31, 2023**	March 31, 2022
Balance, beginning of year	**350,000**	**2,494,000**
Change in loss provision	**289,250**	**(2,218,355)**
Accretion expense (note 27)	**29,750**	**74,355**
	669,000	**350,000**
Less: current portion	**—**	**(299,000)**
Balance, end of year	**669,000**	**51,000**

APMC uses the GOA budgeted commodity price forecast for WTI, Western Canadian Select ("WCS"), condensate and foreign exchange to estimate future cash flows. The most significant pricing variables that would impact the future cash flows of the contract are the forecasted WTI-WCS differential and foreign exchange rates. Due to the long-term nature of the contract, management has performed a sensitivity analysis on the forecasted WTI-WCS differential and the USD/CAD foreign exchange rates by decreasing them by 5 percent. The onerous contract provision would decrease by $315 million if, with all other variables held constant, the forecasted WTI-WCS differential and USD/CAD foreign exchange rates decreased by 5 percent.

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Changes to interest rates also impact the future cash flows under the contract. The onerous contract would increase by $83 million if, with all other variables held constant, the forecasted interest rates increased by 50 basis points.

20. FINANCIAL INSTRUMENTS

The Commission's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, Investment in KXL Expansion Project, accounts payable and accrued liabilities, due to DOE, short term debt, accrued interest on short term debt, long term debt, license fee provision and lease obligations. Except for the Investment in KXL Expansion Project, long term debt, license fee provision, and lease obligations, the carrying values of these financial instruments approximate the fair value due to the short term nature of these instruments. Refer to note 3 of the Consolidated Financial Statements – significant accounting policies for further information related to the Commission's accounting policies related to *IFRS 9 – Financial Instruments.*

The Commission is exposed to a variety of financial risks: interest rate risk, credit risk, liquidity risk and commodity price risk. The nature of the risks faced by the Commission and its policies for managing such risks are detailed below.

(a) Interest rate risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Commission is exposed to interest rate risk from fluctuations in rates on its cash and cash equivalents balance and the interest charged on the short term debt and long term debt.

The Commission manages its exposure to interest rate risk through the use of long term fixed rate debt.

(b) Credit risk

Credit risk is the risk of financial loss to the Commission if a customer or party to a financial instrument fails to meet its contractual obligation and arises principally from the Commission's cash and cash equivalents, cash held in trust, accounts receivable and other financial instruments. The maximum amount of credit risk exposure of these instruments is limited to the carrying value of the balances disclosed in these Annual Financial Statements.

The Commission manages its exposure to credit risk on cash and cash equivalents by placing these financial instruments with the Consolidated Liquidity Solution cash pooling structure maintained by TB&F (note 6).

A substantial portion of the Commission's accounts receivable are with its customers in the oil and gas industry and are subject to normal industry credit risk. The Commission monitors the credit risk and credit rating of all customers on a regular basis. Aged receivable balances are monitored and a credit loss provision is provided in the period in accordance with IFRS 9. Any credit losses on accounts receivable would be costs of APMC that would be recoverable from the DOE through the marketing fee.

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Credit loss provision

	Years ended March 31,	
($000s)	**2023**	2022
Accounts receivable – trade		
Balance, beginning of year	**452**	**248**
Change to loss provision	**157**	**204**
Balance, end of year	**609**	**452**
Accounts receivable – Sturgeon Refinery		
Balance, beginning of year	**500**	**226**
Change to loss provision	**16,903**	**274**
Balance, end of year	**17,403**	**500**
Term loan receivable and accrued interest		
Balance, beginning of year	**—**	**541**
Change to loss provision	**—**	**(541)**
Balance, end of year	**—**	**—**
Total change to loss provision for the year	**17,060**	**(63)**

The loss provision for trade accounts receivable was recorded to General and Administrative Expenses in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). The loss provisions for Sturgeon Refinery accounts receivable and term loan receivable have been recorded to Change in Sturgeon Refinery credit loss provision in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

On April 3, 2023, NWRP executed amendments to existing arrangements for the supply of the Refinery's CO2, and the related product transportation systems. Pursuant to the amended agreements, APMC, through NWRP, agreed to forfeit receipt of its CO2 revenue receivable from a counterparty, who is party to the amended agreements, in order for APMC to gain greater control of CO2 transport and preserve incremental value for C02 in the future. As a result, APMC assessed its CO2 revenue receivable for $16.9 million from the counterparty and determined it to be uncollectible and recorded a credit loss provision as of March 31, 2023.

(c) Liquidity risk

Liquidity risk is the risk that the Commission will not be able to meet its financial obligations as they come due. The Commission actively manages its liquidity through cash, accounts receivables and debt management strategies. The APMC has the ability to obtain financing through external banking credit facilities or from TB&F.

As at March 31, 2023, excluding short term debt, the Commission's non-derivative financial liabilities have contractual maturities (including interest payments where applicable) are summarized below.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

($000s)	Total	< 1 Year	1-3 Years	3-5 Years	More than 5 Years
Accounts payable and accrued liabilities	389,109	389,109	—	—	—
Due to the Department of Energy	211,359	211,359	—	—	—
Long term bonds - KXL Expansion Project[1]	708,000	—	408,000	—	300,000
Interest on KXL Expansion Project bonds	141,343	25,110	27,008	24,900	64,325
Long term bonds - Sturgeon Refinery[1]	800,000	—	—	—	800,000
Interest on Sturgeon Refinery bonds	556,783	27,200	54,400	54,400	420,783
Sturgeon Refinery Processing Agreement provision [2]	669,000	—	219,000	3,000	447,000
Lease liabilities	438	64	124	109	141
License fee provision	87,000	—	7,000	8,000	72,000
	3,563,032	**652,842**	**715,532**	**90,409**	**2,104,249**

1. Represents the face value due at maturity.
2. The amount more than 5 years represents the present value of estimated net cash inflows from the Sturgeon Refinery in later years.

(d) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollars but also worldwide economic events that influence supply and demand.

The Commission’s operational results and financial condition are impacted by prices realized on sales of refined products, feedstock purchases and tolls at the Sturgeon Refinery. In addition, the Commission’s financial position and results are also impacted by changes in estimates of future commodity prices used in the determination of the net cash flows of the Processing Agreement. As at March 31, 2023, the Commission does not have any commodity price risk management contracts. Movement in commodity prices could have a significant positive or negative impact on the Commission’s net income (loss).

(e) Foreign exchange risk

Foreign exchange risk is the risk that the fair value or future cash flows of an exposure will fluctuate because of changes in foreign exchange rates. The Commission’s exposure to the risk of changes in foreign exchange rates primarily relate to the Commission’s KXL Investment. A portion of the KXL Investment is denominated in a foreign currency and this exposes the Commission to the risk that the fair value will fluctuate due to changes in the exchange rate.

The Commission mitigates foreign exchange risk by minimizing its US currency held.

Capital Management and Liquidity

The Commission's objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its business plans. The Commission considers its capital structure to include equity (deficit), the short and long term debt available borrowings under outstanding debt agreements, and net working capital (deficit). The Commission’s objectives when managing capital are to safeguard the Commission’s ability to continue as a going concern and provide returns to the DOE through responsible marketing of conventional crude oil royalty volumes and its other business activities. The Commission does not have any externally imposed restrictions on its capital. The Commission monitors its current and forecasted capital structure in response to changes in economic conditions and the risk characteristics of its business activities. Adjustments are made on an ongoing basis in order to meet its capital management objectives. In light of the continued uncertainty in the macroeconomic environment, the Commission continues to monitor interest rate volatility given the current economic environment with increased inflationary pressures and has converted a portion of short term borrowings into longer maturity borrowings (note 15).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

The APMC believes that its current financial obligations including current commitments and working capital deficit (as defined as current assets, less current liabilities) will be adequately funded by the available borrowing capacity on the Order of Councils over the next twelve months.

21. COMMITMENTS

The estimated NWRP tolls under the Processing Agreement are as follows for future years ended:

(In $ millions)	March 31, 2024	March 31, 2025	March 31, 2026	March 31, 2027	March 31, 2028	Beyond 2028	Total
NWRP Tolls	**940**	**961**	**1,030**	**857**	**843**	**35,487**	**40,118**

Under the Processing Agreement, after COD, the Commission is obligated to pay a monthly toll comprised of debt principal repayment, debt service costs and operating components. The processing agreement has a term of 40 years starting with the Toll Commencement Date (June 1, 2018). The Commission has very restricted rights to terminate the Processing Agreement, and is unconditionally obligated to pay its 75 percent pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. The tolls, under the Processing Agreement, assuming market interest rates and a 2 percent operating cost inflation rate, are estimated above. The toll commitments above are undiscounted and are estimated up to the end of the Processing Agreement term (May 31, 2058). These undiscounted tolls do not take into account the net margin received on the sale of APMC’s bitumen feedstock.

The estimated commitments for office lease and parking costs are as follows for future years ended:

(In $000s)	March 31, 2024	March 31, 2025	March 31, 2026	March 31, 2027	March 31, 2028	Beyond 2028	Total
Office lease and parking [1]	**473**	**473**	**462**	**435**	**429**	**1,145**	**3,417**

1. Includes estimates for annual operating costs and property taxes.

The office lease has been capitalized as a right-of-use-asset and the sub-leased office space is with a related party as detailed in note 22.

22. RELATED PARTY TRANSACTIONS

The DOE pays the Commission a fee to market crude oil on its behalf under conventional crude oil marketing activities, reported as marketing fees within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). The amounts owing to the DOE have been disclosed in note 14.

The Commission enters into transactions with the DOE, a related party, in the normal course of business. For the year ended March 31, 2023, the DOE incurs costs for salaries on behalf of the Commission, as recognized under wages and benefits of $1.3 million (year ended March 31, 2022 - $2.0 million) within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

Technology and Innovation (formerly Service Alberta), a related party provided the software and maintenance services totaling $0.6 million for the year ended March 31, 2023 (year ended March 31, 2022 - $0.3 million). These expenditures were recognized within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

The Commission has a sublease agreement for office premises with the Alberta Energy Regulator (the "AER"), a related party. For the year ended March 31, 2023, the APMC paid $0.4 million (year ended March 31, 2022 - $0.3 million) to the AER for office rent and parking expenses, shared services, and leasehold improvements.

The Commission has outstanding short term debt and long term debt with TB&F (note 15 and 17).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

The Commission formerly had a Term Loan Receivable from NWRP that was settled on June 30, 2021. Information on the Term Loan Receivable settlement and summarized financial information for NWRP is found in note 12. Refer to note 4(c) for a description of the Sturgeon Refinery, note 4(d) for the NWRP monthly toll commitment and note 19 for the Sturgeon Refinery Processing Agreement Provision.

Information on the Commission's investment in the KXL Expansion Project Class A partnership interests is found in note 10.

The Board members of the Commission, executive management and their close family members are deemed related parties of the Commission. Compensation for Board members and executive management is disclosed in note 26.

23. OTHER INCOME

During the year ended March 31, 2023, APMC recognized nil (year ended March 31, 2022 - $71.3 million) of other income related to a litigation settlement received by NWRP. The settlement was received for the benefit of the Tollpayers.

24. TURNAROUND EXPENDITURES

The Commission paid $164.3 million (2022 - $23.6 million) to NWRP for tolls related to turnaround costs. As the Commission had recognized an onerous contract provision at March 31, 2023 and March 31, 2022, the tolls related to turnaround costs were expensed as incurred and not recognized as a prepaid expense.

25. GENERAL AND ADMINISTRATIVE EXPENSES

	Years ended March 31,	
($000s)	**2023**	2022
Wages and benefits	**6,607**	5,884
Software and maintenance	**1,195**	861
Consulting	**2,711**	5,454
Dues and subscriptions	**254**	263
Director fees	**106**	119
Office rent and property taxes	**344**	158
Change in loss provision for accounts receivable	**157**	204
Other	**186**	119
Total general and administrative expenses	**11,560**	13,062

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

26. KEY MANAGEMENT COMPENSATION

Key management personnel include the Commission's Board Members, Chief Executive Officer, Chief Financial Officer, Vice President, Operations and Vice President, Business Development and Marketing. The amounts relating to board members and key management compensation for the years ended March 31, 2023 and 2022 are as follows:

	Base Salary		Other Cash Benefits[2]		Other Non-cash Benefits[3]		Total	
($000s)	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Board Members[1]	**—**	—	**108**	119	**—**	—	**108**	119
Chief Executive Officer	**301**	301	**59**	94	**7**	6	**367**	401
Chief Financial Officer	**296**	281	**52**	70	**7**	6	**355**	357
Vice President, Operations	**277**	267	**81**	52	**6**	5	**364**	324
Vice President, Business Development and Marketing	**228**	220	**38**	42	**6**	4	**272**	266
General Counsel [4]	**275**	—	**51**	—	**6**	—	**332**	—
Director, Finance [5]	**—**	117	**—**	208	**—**	2	**—**	327
	1,377	1,186	**389**	585	**32**	23	**1,798**	1,794

1. The Chair of the Board (Deputy Minister, DOE) and one director (Assistant Deputy Minister, DOE) are unpaid. There are five independent Board Members. The independent Board Members receive annual retainer and meeting fees.
2. As per their employment contracts, the key management personnel receive cash payments in lieu of benefits. No bonuses were paid during the year.
3. Included in Other Non-cash benefits is parking.
4. The General Counsel was hired effective April 4, 2022.
5. The Director, Finance effective end date was September 29, 2021. Other Cash Benefits also includes severance and unpaid earned vacation.

27. FINANCE COSTS

Finance costs consist of the following:

($000s)	**March 31, 2023**	March 31, 2022
Accretion Expense - license fee provision (note 18)	**7,420**	5,463
Amortization of premium on long term debt (note 17)	**(10,022)**	(6,496)
Accretion Expense - Sturgeon Refinery Processing Agreement Provision (note 19)	**29,750**	74,355
Interest Expense	**74,344**	15,341
Total Finance Costs	**101,492**	88,663

28. INCOME TAXES

The Commission is exempt from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd. (the "US subsidiary"), a Delaware incorporated company, and 2254746 Alberta Ltd. (the "Canadian holding company"), an Alberta incorporated company, have exposure to US federal and state corporate income taxes.

Through the tax year ended December 31, 2021, the US subsidiary has estimated US net operating losses for income tax purposes of US$357 million, which carry forward indefinitely. US tax returns for the tax year ended December 31, 2021 are subject to examination by the IRS. The preparation and filing of the US tax return for the tax year ended December 31, 2022 is anticipated to occur later in 2023, at which time further net operating losses may be determined.

The Commission does not currently have any deferred income tax assets or liabilities.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

29. SUPPLEMENTAL CASH FLOW

Details of changes in non-cash working capital from operating activities include the following:

	Years ended March 31,	
($000s)	**2023**	2022
Restricted cash	**(4,065)**	(61,286)
Accounts receivable	**175,543**	(254,541)
Inventory	**25,097**	(43,993)
Accounts payable and accrued liabilities	**(159,201)**	72,358
Due to the Department of Energy	**(7,590)**	160,307
Changes in non-cash working capital from operating activities	**29,784**	(127,155)

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2023
(Expressed in thousands of Canadian dollars, unless stated otherwise)

30. SEGMENT INFORMATION

These reportable segments of the APMC have been derived because they are the segments: (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the APMC's executive leadership team to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available.

The Commission's reportable segments were determined based on differences in products and support services offered under its mandate as disclosed in note 1. The Commission has four reportable segments: conventional crude marketing operations, the Sturgeon Refinery, the Investment in NWRP and the KXL Expansion Project. The Sturgeon Refinery segment accounts for the APMC's 75 percent interest as a Tollpayer in the Sturgeon Refinery, or IPTA. As a result, the APMC provides financial information on revenues and expenses of each segment, but not total assets or liabilities by segment.

Years ended March 31, 2023 and 2022

	Conventional Crude Oil Marketing		Sturgeon Refinery (Tollpayer)		NWRP Joint Venture (Refinery Owner)		KXL Expansion Project		Total	
($000s)	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
REVENUES										
Refinery sales	**—**	—	**2,733,082**	2,381,861	**—**	—	**—**	—	**2,733,082**	2,381,861
Other income	**—**	—	**—**	71,250	**—**	—	**—**	—	**—**	71,250
Marketing fee income	**12,050**	11,201	**—**	—	**—**	—	**—**	—	**12,050**	11,201
	12,050	11,201	**2,733,082**	2,453,111	**—**	—	**—**	—	**2,745,132**	2,464,312
Finance income	**129**	77	**2,451**	26,461	**—**	—	**—**	—	**2,580**	26,538
	12,179	11,278	**2,735,533**	2,479,572	**—**	—	**—**	—	**2,747,712**	2,490,850
EXPENSES										
Refinery feedstock purchases	**—**	—	**1,884,148**	1,759,753	**—**	—	**—**	—	**1,884,148**	1,759,753
Refinery tolls	**—**	—	**878,508**	780,451	**—**	—	**—**	—	**878,508**	780,451
Turnaround expenditures	**—**	—	**164,279**	23,604	**—**	—	**—**	—	**164,279**	23,604
General and administrative	**10,735**	10,079	**374**	1,529	**—**	—	**451**	1,454	**11,560**	13,062
Depreciation and amortization	**1,166**	1,110	**—**	—	**—**	—	**—**	—	**1,166**	1,110
Loss (gain) on foreign exchange	**21**	(67)	**(78)**	(362)	**—**	—	**(5,745)**	(3,145)	**(5,802)**	(3,574)
Finance costs	**6**	3	**63,782**	78,010	**7,420**	5,463	**30,284**	5,187	**101,492**	88,663
Gain from North West Redwater Partnership	**—**	—	**—**	—	**(97,361)**	(2,611)	**—**	—	**(97,361)**	(2,611)
Provision (Recovery) for Sturgeon Refinery	**—**	—	**306,153**	(2,218,622)	**—**	—	**—**	—	**306,153**	(2,218,622)
Fair value gain investment in KXL Expansion Project	**—**	—	**—**	—	**—**	—	**(9,054)**	(10,471)	**(9,054)**	(10,471)
Total expenses	**11,928**	11,125	**3,297,166**	424,363	**(89,941)**	2,852	**15,936**	(6,975)	**3,235,089**	431,365
Net income (loss) and comprehensive income (loss)	**251**	153	**(561,633)**	2,055,209	**89,941**	(2,852)	**(15,936)**	6,975	**(487,377)**	2,059,485

Post-Closure Stewardship Fund

Financial Statements

For the Year Ended March 31, 2023

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Auditor General OF ALBERTA

Independent Auditor's Report

To the Minister of Energy and Minerals

Report on the Financial Statements

Opinion

I have audited the financial statements of the Post-Closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2023, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Post-Closure Stewardship Fund as at March 31, 2023, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

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

Other information

Management is responsible for the other information. The financial statements of the Post-Closure Stewardship Fund are included in the *Annual Report of the Ministry of Energy and Minerals*. The other information comprises the information included in the *Annual Report of the Ministry of Energy and Minerals* relating to the Post-Closure Stewardship Fund, but does not include the financial statements of the Post-Closure Stewardship Fund and my auditor's report thereon. The *Annual Report of the Ministry of Energy and Minerals* is expected to be made available to me after the date of this auditor's report.

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

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

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

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

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

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

Those charged with governance are responsible for overseeing the Post-Closure Stewardship Fund's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

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

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

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

events or conditions may cause the Post-Closure Stewardship Fund to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

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

June 6, 2023
Edmonton, Alberta

Statement of Operations

Post-Closure Stewardship Fund
Year Ended March 31, 2023
(in thousands)

	2023		2022
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	$ 230	$ 447	$ 218
Investment Income	-	51	4
Net Operating Results	230	498	222

The accompanying notes are part of these financial statements.

Statement of Financial Position

Post-Closure Stewardship Fund
As of March 31, 2023
(in thousands)

	2023	2022
Assets		
Cash (Note 4)	$ 1,830	$ 1,561
Accounts Receivable	339	110
Net Financial Assets	**$ 2,169**	**$ 1,671**
Net Financial Assets at Beginning of Year	$ 1,671	$ 1,449
Annual Operating Results	498	222
Net Financial Assets at End of Year	**$ 2,169**	**$ 1,671**

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Post-Closure Stewardship Fund
Year Ended March 31, 2023
(in thousands)

	2023		2022
	Budget	Actual	Actual
Annual Operating Results	$ 230	$ 498	$ 222
Increase in Net Financial Assets	$ 230	$ 498	$ 222
Net Financial Assets at Beginning of Year	-	1,671	1,449
Net Financial Assets at End of Year	**$ 230**	**$ 2,169**	**$ 1,671**

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Post-Closure Stewardship Fund
Year Ended March 31, 2023
(in thousands)

	2023	2022
Operating Transactions		
Net Operating Results	$ 498	$ 222
(Increase) Decrease in Accounts Receivable	(229)	23
Increase in Cash and Cash Equivalents	**$ 269**	**$ 245**
Cash and Cash Equivalents at Beginning of Year	1,561	1,316
Cash and Cash Equivalents at End of Year	**$ 1,830**	**$ 1,561**

The accompanying notes are part of these financial statements.

Notes to Financial Statements

Post-Closure Stewardship Fund
March 31, 2023

NOTE 1 **AUTHORITY & PURPOSE**

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

The MMA provides an option to the Minister to issue a Closure Certificate to an approved operator after the final injection of captured carbon dioxide has been completed and after satisfying the closure period that is to be specified in regulations. There is no liability to the Fund until such a Closure Certificate has been issued.

The Fund was established to address certain long-term liabilities that may arise from approved projects for the injection of captured carbon dioxide into subsurface reservoirs for sequestration subsequent to the issuance of a Closure Certificate.

The Injection Levy Rate(s) are set through Ministerial Orders and are reviewed on a regular schedule. Based on the result of the review, the rate(s) will be amended as necessary.

NOTE 2 **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES**

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

(a) **Basis of Financial Reporting**

Revenues
Revenues are reported on the accrual basis of accounting. The volume of carbon dioxide injected is based upon reported injection provided by the operator. Third party verification on the volume of injection will take place in the month of October, for injection to September 30. The Injection Levy is calculated based on the net present value of estimated future costs arising from the injection.

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

NOTE 3 **INJECTION LEVY**

The Injection Levy is set aside for Post-Closure Care of the injection site. Post-Closure Care occurs after the issuance of the Closure Certificate and includes the continual monitoring costs of the captured carbon dioxide injection sites and any remediation of the sites that may be required.

At March 31, 2023, there is only one approved carbon dioxide injection site. The estimated present value of the future costs for this site, based on modeling of potential requirement under current technology, is $10.9 million. Currently, approximately 32% of the site's capacity has been used. The project is expected to inject for a 25-year period.

As the site remains active and no Closure Certificate has been issued, there is no expectation of any withdrawals from the Fund at this time.

NOTE 4 **CASH**

Cash and cash equivalents includes demand deposits in the Consolidated Liquidity Solution (CLS). Effective July 4, 2022, the CLS replaces the Consolidated Cash Investment Trust Fund (CCITF) as the Province's cash pooling structure. The new CLS structure will enhance the effectiveness and efficiency from Province's cash management perspective. A CLS participant is paid interest on monthly basis on their cash balance at an interest rate based on 12 week rolling average of the Province's 3 month cost of borrowing.

The fund earns interest at an effective rate of 3.04% per annum (2022 - 0.24%).

NOTE 5 **APPROVAL OF FINANCIAL STATEMENTS**

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

Canadian Energy Centre Ltd.

Financial Statements

Year Ended March 31, 2023

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Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Canadian Energy Centre Ltd.

Report on the Financial Statements

Opinion

I have audited the financial statements of the Canadian Energy Centre Ltd. (the CEC), which comprise the statement of financial position as at March 31, 2023, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the CEC as at March 31, 2023, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

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

Other information

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

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

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

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

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

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

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

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

Auditor's responsibilities for the audit of the financial statements

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

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

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

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

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

May 9, 2023
Edmonton, Alberta

Statement of Operations

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

	2023		2022
	Budget (Note 4)	**Actual**	**Actual**
Revenues			
Government transfers			
Government of Alberta grants	$ 31,789,000	$ 31,789,000	$ 7,701,784
Other Revenue	-	537	-
	31,789,000	**31,789,537**	**7,701,784**
Expenses (Schedule 1)			
Resource Development and Management	31,789,000	26,058,712	4,158,577
	31,789,000	**26,058,712**	**4,158,577**
Annual operating surplus	**-**	**5,730,825**	3,543,207
Annual surplus	**-**	**5,730,825**	**3,543,207**
Accumulated surplus at beginning of year	4,517,394	4,517,394	974,187
Accumulated surplus at end of year (Note 8)	**$ 4,517,394**	**$ 10,248,219**	**$ 4,517,394**

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

Statement of Financial Position

Canadian Energy Centre Ltd.
As at March 31, 2023

	2023	2022
Financial Assets		
Cash	$ 9,891,211	$ 4,742,986
Accounts receivable	1,156,294	122,380
	11,047,505	**4,865,366**
Liabilities		
Accounts payable and other accrued liabilities (Note 6)	2,660,690	654,126
	2,660,690	**654,126**
Net Financial Assets	**8,386,815**	**4,211,240**
Non-Financial Assets		
Prepaid expenses (Note 7)	1,861,404	306,154
	1,861,404	**306,154**
Net Assets		
Accumulated surplus (Note 8)	**10,248,219**	**4,517,394**
	$ 10,248,219	**$ 4,517,394**

Contingent liabilities (Note 10)
Contractual obligations (Note 11)

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

Statement of Change in Net Financial Assets

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

	2023		2022
	Budget	Actual	Actual
Annual surplus	$ -	$ 5,730,825	$ 3,543,207
Increase in prepaid expenses	-	(1,555,250)	(262,667)
Increase in net financial assets	-	4,175,575	3,280,540
Net financial assets at beginning of year	4,211,240	4,211,240	930,700
Net financial assets at end of year	$ 4,211,240	$ 8,386,815	$ 4,211,240

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

Statement of Cash Flows

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

	2023	2022
Operating transactions		
Annual surplus	$ 5,730,825	$ 3,543,207
Increase in accounts receivable	(1,033,914)	(22,505)
Increase in prepaid expenses	(1,555,250)	(262,667)
Increase/(decrease) in accounts payable and other accrued liabilities	2,006,564	(361,553)
Cash provided by operating transactions	**5,148,225**	**2,896,482**
Increase in cash	**5,148,225**	**2,896,482**
Cash at beginning of year	**4,742,986**	**1,846,504**
Cash at end of year	**$ 9,891,211**	**$ 4,742,986**

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

Note 1 AUTHORITY

The Canadian Energy Centre Ltd. (the "Corporation") is a provincial corporation incorporated under the *Business Corporations Act* (Alberta) on October 9, 2019.

The Corporation is wholly owned by His Majesty the King in the Right of Alberta as represented by the Minister of Energy. It is governed by a Board of Directors appointed by the province. The Board consists of three Cabinet Ministers appointed by the Government of Alberta.

The mandate of the Corporation is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy.

As a provincial corporation, the Corporation is exempt from income taxes under the *Income Tax Act.*

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

a. Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting.

<u>Government Transfers</u>

Transfers from all governments are referred to as government transfers.

Government transfers and associated externally restricted investment income are recognized as deferred contributions if the eligibility criteria for use of the transfer, or the stipulations together with the Corporation's actions and communications as to the use of the transfer, create a liability. These transfers are recognized as revenue as the stipulations are met and, when applicable, the Corporation complies with its communicated use of these transfers.

All other government transfers, without stipulations for use of the transfer, are recognized as revenue when the transfer is authorized, and the Corporation meets the eligibility criteria (if any).

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

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

a. Basis of Financial Reporting (Continued)

Expenses

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

Valuation of Financial Assets and Liabilities

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

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

The Corporation does not have any financial instruments classified in the fair value category and does not hold derivative contracts. Therefore, these statements do not present a statement of remeasurement gains and losses as the Corporation is not exposed to remeasurement gains and losses.

Financial Assets

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

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

Cash

Cash comprises of cash on hand and demand deposits.

Accounts receivable

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

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

a. Basis of Financial Reporting (Continued)

Liabilities

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

Non-Financial Assets

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

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

Non-financial assets are limited to prepaid expenses.

<u>Tangible Capital Assets</u>

Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement, or betterment of the assets. Cost includes overhead directly attributable to construction and development, as well as interest costs that are directly attributable to the acquisition or construction of the asset, and asset retirement cost. The cost, less residual value, of the tangible capital assets, excluding land, is amortized on a straight-line basis over their estimated useful lives.

The capitalization threshold for all capital assets is $2,000. The Corporation, however, does not have any capital assets. Therefore, no tangible capital assets are reported in the financial statements.

<u>Prepaid expenses</u>

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS

The following new accounting standard of Public Sector Accounting Board is unapplicable to the corporation:

- **PS 3280 Asset Retirement Obligations**
  This accounting standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. The Corporation plans to adopt this accounting standard on a modified retroactive basis, consistent with the transitional provisions in PS 3280, and information presented for comparative purposes will be restated. The impact of the adoption of this accounting standard on the financial statements is currently being analyzed.

In addition to the above, the Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2023.

- **PS 3400 Revenue**
  This accounting standard provides guidance on how to account for and report on revenue, and specifically, it differentiates between revenue arising from exchange and non-exchange transactions.

- **PS 3160 Public Private Partnerships**
  This accounting standard provides guidance on how to account for public private partnerships between public and private sector entities, where the public sector entity procures infrastructure using a private sector partner.

Note 4 BUDGET

The below Budget was approved by the Board for the fiscal 2023 year.

Budget		Amount	Approval Date
April 2022 – March 2023 Budget	$	17,200,777	March 30, 2022
US Energy Security Campaign		6,000,000	March 28, 2022
G7 Leaders on Energy Security		300,000	May 30, 2022
US Energy Security Campaign		1,000,000	October 05, 2022
US Campaign		1,624,332	December 05, 2022
European Campaign		5,663,891	December 05, 2022
Total	**$**	**31,789,000**	

Revenue budget reported in the Statement of Operations reflects actual cash received during the year and expenses budget reported in the Statement of Operations reflects the budget.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

Note 5 FINANCIAL RISK MANAGEMENT

The Corporation is exposed to some financial risks. These financial risks include credit risk and liquidity risk.

(a) Credit Risk

Credit risk is the risk of loss arising from the failure of a counterparty to fully honour its financial obligations with the Corporation. Credit risk on accounts receivable is considered low.

As of March 31, 2023, the balance of accounts receivable does not contain amounts that were uncollectible.

(b) Liquidity Risk

Liquidity risk is the risk that the Corporation will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the Corporation are met through grants from the Ministry of Energy. The Corporation manages liquidity risks by its budget processes and regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations, including operating expenses.

Note 6 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

	2023	2022
Accounts Payable	$ 1,331,479	$ 163,703
Accrued liabilities	1,264,748	447,434
ATB Alberta Rewards Business Card	13,015	(6,483)
Accrued Salaries and Wages	12,064	6,000
Vacation Payable	39,384	43,472
Balance at end of year	**$ 2,660,690**	**$ 654,126**

Note 7 PREPAID EXPENSES

93% of 2023 prepaid expenses is related to RFP – Agency of Record expense for campaign media buys that ran into April of 2024 year. The balance will be fully expensed in 2024 year.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

Note 8 ACCUMULATED SURPLUS

Accumulated surplus is comprised of the following:

		2023		2022
Balance at beginning of year	$	4,517,394	$	974,187
Annual surplus		5,730,825		3,543,207
Balance at end of year	**$**	**10,248,219**	**$**	**4,517,394**

Note 9 SHARE CAPITAL

Share capital is comprised of the following:

		2023		2022
Issued:				
1 Common Share	$	6,800	$	6,800
Balance at end of year	**$**	**6,800**	**$**	**6,800**

Note 10 CONTINGENT LIABILITIES

As of March 31, 2023, the Corporation was not named as defendant in any specific legal actions.

Note 11 CONTRACTUAL OBLIGATIONS

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

		2023		2022
Obligations under contracts	$	845,318	$	4,974,141
Balance at end of year	**$**	**845,318**	**$**	**4,974,141**

Estimated payment requirement for the next year is as follows:

		Contracts		Total
2023-2024	$	845,318	$	845,318
	$	845,318	**$**	**845,318**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2023

Note 12 COMPARATIVE FIGURES

Certain 2022 figures have been reclassified, where necessary, to conform to the 2023 presentation.

Note 13 APPROVAL OF FINANCIAL STATEMENTS

The Board approved the financial statements of the Corporation.

Expenses – Detailed by Object

Canadian Energy Centre Ltd.
Year Ended March 31, 2023
(Schedule 1)

	2023		2022
	Budget	**Actual**	**Actual**
Salaries and Benefits	$ 1,698,538	$ 1,479,406	$ 1,571,200
Office Infrastructure	142,308	79,130	77,130
General and Administrative Expenses	43,458	70,253	18,238
Legal	177,919	59,971	137,211
Accounting	200,000	200,000	150,000
IT	8,675	8,375	6,000
Communications and Marketing	-	-	475,642
Website	43,000	34,667	50,180
Social Advertising	632,587	696,711	441,109
Research	1,321,482	1,303,614	196,347
Media	192,890	162,338	98,674
Freelance – Indigenous	-	-	2,487
RFP – Agency of Record	26,612,459	21,937,301	934,359
Contingency – Other	715,684	26,946	-
Total Expenses	**$ 31,789,000**	**$ 26,058,712**	**$ 4,158,577**

Salary and Benefits Disclosure

Canadian Energy Centre Ltd.
Year Ended March 31, 2023
(Schedule 2)

	2023			2022
	Base Salary (1)	Other Cash Benefits (2)	Total	Total
Chief Executive Officer (CEO) (3)	$ 194,252	$ 47,340	$ 241,592	$ 241,366
Executive Director (4)	109,666	26,768	136,434	213,278
Executive Director (5)	-	-	-	170,227
Executive Director (6)	171,600	41,904	213,504	90,518
Executive Director (7)	54,780	13,377	68,157	-
Total Expenses	**$ 530,298**	**$ 129,389**	**$ 659,687**	**$ 715,389**

The Chair and Members of the Board of Directors receive no remuneration for participation on the Board.

1. Base salary includes regular salary.
2. Other cash benefits include compensation in lieu of pension, health benefits and severance. No bonuses were paid during the year.
3. CEO was hired on October 9, 2019 with an annual base salary of $194,252 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.
4. Executive Director was hired on January 27, 2020 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively. Last day of employment was November 11, 2022.
5. Executive Director was hired on December 1, 2019 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively. Last day of employment was October 31, 2021.
6. Executive Director was hired on January 8, 2020, and was promoted to current position effective November 1, 2021 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.
7. Executive Director was hired on December 5, 2022 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.

Related Party Transactions

Canadian Energy Centre Ltd.
Year Ended March 31, 2023
(Schedule 3)

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. Related parties also include key management personnel and close family members of those individuals in the Corporation.

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

	2023	2022
Revenues		
Grants	$ 31,789,000	$ 7,701,784
	31,789,000	7,701,784
Expenses		
Rent	57,354	57,354
Insurance coverage	1,516	1,501
	58,870	58,855
Common Share - Department of Energy	$ 6,800	$ 6,800

Other Financial Information

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Lapse/Encumbrance (unaudited)

The following has been prepared pursuant to Section 24(4) of the *Financial Administration Act*.

Department of Energy
Year Ended March 31, 2023
(in thousands)

	Voted Estimate(1)	Supplementary Estimate(2)	Adjustments	Adjusted Voted Estimate	Voted Actuals(3)	Over Expended (Unexpended)
EXPENSE VOTE BY PROGRAM						
Ministry Support Services						
1.1 Minister's Office	$ 995	$ -	$ -	$ 995	$ 555	$ (440)
1.3 Deputy Minister's Office	667	32	-	699	657	(42)
1.5 Corporate Services	2,287	1,681	-	3,968	2,780	(1,188)
	3,949	1,713	-	5,662	3,992	(1,670)
Resource Development and Management						
2.1 Energy Operations	17,215	63	-	17,278	15,137	(2,141)
2.2 Energy Policy	31,566	10,082	-	41,648	28,843	(12,805)
2.3 Industry Advocacy	27,000	4,789	-	31,789	31,789	-
	75,781	14,934		90,715	75,769	(14,946)
Cost of Selling Oil						
3 Cost of Selling Oil	144,000	351,581	(63,802)	431,779	429,381	(2,398)
Economic Recovery Support						
4.1 Site Rehabilitation Program	297,200	257,190	-	554,390	438,618	(115,772)
4.2 Mineral Strategy	12,811	-	-	12,811	12,811	-
	310,011	257,190	-	567,201	451,429	(115,772)
CAPITAL GRANTS						
Economic Recovery Support						
4.3 Alberta Petrochemicals Incentive Program	-	10,800	-	10,800	10,837	37
Total	$ 533,741	$ 636,218	(63,802)	$ 1,106,157	$ 971,407	$ (134,750)
Encumbrance/(Lapse)						$ (134,750)
CAPITAL INVESTMENT VOTE BY PROGRAM						
Ministry Support Services						
1.3 Corporate Service	500	500	-	1,000	308	(692)
	$ 500	$ 500	$ -	$ 1,000	$ 308	$ (692)
Encumbrance/(Lapse)						$ (692)

(1) As per "Expense Vote by Program" and "Capital Investment Vote by Program", page 75 of the 2023-24 Government Estimates, 2022-23 budget.
(2) Supplementary Supply Estimates approved on March 16, 2023.
(3) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

Annual Report Extracts and Other Statutory Reports

Statutory Report: Public Interest Disclosure Act

Section 32 of the *Public Interest Disclosure (Whistleblower Protection) Act* reads:

32(1) Every chief officer must prepare a report annually on all disclosures that have been made to the designated officer of the department, public entity or office of the Legislature for which the chief officer is responsible.

(2) The report under subsection (1) must include the following information:

(a) the number of disclosures received by the designated officer, the number of disclosures acted on and the number of disclosures not acted on by the designated officer;

(b) the number of investigations commenced by the designated officer as a result of disclosures;

(c) in the case of an investigation that results in a finding of wrongdoing, a description of the wrongdoing and any recommendations made or corrective measures taken in relation to the wrongdoing or the reasons why no corrective measure was taken.

(3) The report under subsection (1) must be included in the annual report of the department, public entity or office of the Legislature if the annual report is made publicly available.

There were no disclosures of wrongdoing filed with my office for your department between April 1, 2022, and March 31, 2023.