Responses to the Public Accounts Committee

1. **Ms Hoffman:** Has the department established measures to determine whether or not the objectives that the regulated rate option and renewable electricity program are being met? [PA-71]

   Answer:
   - The key metrics to ensure the objectives of the Regulated Rate Option are being met are:
     - to ensure all customers who are on the Regulated Rate Option are not billed more than 6.8 cents per kilowatt hour from June 1, 2017 to May 31, 2021; and
     - payments to Regulated Rate Option retailers are made within 30 days of receiving their deferral account statement.
   - These metrics were published on page 56 of the 2018-19 Ministry annual report in June 2019.
   - The key metric to ensure the objectives of the Renewable Electricity Program (REP) are being met is:
     - the percentage of electricity generated in Alberta that comes from renewable sources.
   - This metric was published on page 62 of the 2018-19 Ministry annual report in June 2019.

2. **Mr. Walker:** Can the ministry explain or elaborate on the impact that a consumer carbon tax applied in Alberta until recently had on industry and investor confidence and our investment climate over the past few years? [PA-73]

   Answer:
   The Government of Alberta is in the process of publishing a validated assessment of the economic and emissions impacts of the carbon levy and Climate Leadership Plan policies in Alberta. Impacts to “industry and investor confidence and our investment climate” are generally subjective and not able to be assessed – especially in the context of other major economic shocks that occurred in that period, including the oil price crash and associated recession, and the impact of the Fort McMurray fires and reconstruction activities. The analysis will quantify impacts to gross domestic product and costs to households, relative to a business as usual policy scenario, which are contributors to these more qualitative factors.

3. **Mr. Feehan:** Perhaps I can ask that when you get a chance to do some written submissions you give us a bit of a sense of the percentage of the wells that are being resolved at this particular time as compared to previously so that I can get a sense of whether or not we're moving closer to getting control over these wells.

   I'm also very interested in the amount of unpaid royalties that we have when we have abandoned wells. What's the loss to us as government when we have abandoned wells? If you don't have that now, that's fine, but perhaps you can provide that in the future so I have some sense of that. [PA-74]

   Answer:
   An abandoned well is a well that is no longer needed to support oil and gas development. It is permanently plugged, cut, and capped according to the requirements outlined in the AER's Directive 020.

   An orphan is a well, pipeline, or facility that does not have any legally responsible and/or financially able party to conduct abandonment and reclamation responsibilities.

   Table 1 provides the Orphan Well Association's (OWA) total inventory at the end of the 2018-19 fiscal year, along with the number of sites decommissioned and reclaimed, including the percentage reduction of the total inventory as a result of the work completed.

Table 1: OWA Activity for Fiscal Year 2018-19

Activity	Inventory at the end of 2018-19 fiscal year (A)	Activities completed in 2018-19 fiscal year (B)	2018-19 fiscal year end results {B*100/(A+B)}
Wells to be decommissioned (abandoned)	3128	799	20%
Pipelines to be decommissioned (abandoned)	3961	967	20%
Sites to be reclaimed	2151	238	10%

Table 2 provides a breakdown of the work completed by the OWA in fiscal year 2018-19 that is attributed to the funding received through the Orphan Well Loan Program. Approximately 60 per cent of the work completed by the OWA was funded through the loan program.

Table 2: OWA Activity from Orphan Well Loan Program

Activity	Total for fiscal year 2018-19	Due to OWA Loan Program Contribution for fiscal year 2018-19
Wells decommissioned (abandoned)	799	479
Pipeline decommissioned (abandoned)	967	580
Reclamation completed	238	143

Table 3 below describes the abandonment and reclamation activity for the 2018-19 fiscal year, completed by active companies (i.e. activity not related to orphan sites).

Table 3: Industry Abandonment and Reclamation Activity for 2018-19 Fiscal Year (Excluding OWA)

Industry Activity	Total for Fiscal year 2018-19
Number of wells decommissioned and left in a safe and secure condition	4,721
Number of pipelines decommissioned and left in a safe and secure condition	4,108
Number of facilities decommissioned and left in a safe and secure condition	113
Number of wells/pipelines/sites reclaimed	Data not available

Abandoning non-producing or low-producing sites, whether they are orphaned or with active companies, may have a small overall impact on royalties collected. While royalty arrears may be associated with insolvent companies, lost royalties, if any, from individual orphan sites that have been abandoned cannot be accurately determined.

For more information on the current inventory please see: https://www.alberta.ca/upstream-oil-and-gas-liability-and-orphan-well-inventory.aspx

4. **Mr. Guthrie:** Do you know how much capacity we need to move this supply to actually make a difference? [PA-75]

   Answer:
   Based on the Canadian Association of Petroleum Producers (CAPP's) 2019 Crude Oil Market Outlook, there will be a continued shortage of egress from Western Canada. Current pipeline capacity is approximately 4.2 million barrels per day (bpd) (as of 2018). By the end of 2020, using CAPP's outlook it is projected that supply could outpace export capacity by 800,000 bpd, as production is anticipated to be capable of 5 million bpd – and increasing. This shortage of egress will be alleviated with crude by rail shipments (which in 2018 reached 350 thousand bpd and in August reached 310 thousand bpd), enhancements to existing pipelines – some of which are already in progress or completed – and from the development of new pipelines and expansions, including Enbridge's Line 3. Based on current production trends, in order to ensure a sufficient balance of supply and takeaway capacity, the province will require Line 3's completion, and at least one of the other two pipeline expansions—Trans Mountain or Keystone XL – in the years to come.

   Other forecasts would have different production levels depending on their assumptions.

   In the short-term, curtailment is being utilized to align production and takeaway capacity. Through curtailment, crude oil and bitumen demand and anticipated takeaway capacity are factored into the amount monthly production permitted for curtailed producers. The amount of additional potential supply is dependent on each company's forecast of what they can produce without limitations. Other factors include potential investment in drilling activity, new projects and expansions.

   It is also generally looked at from a broader western Canadian perspective as all three provinces put oil into the internal market and export pipelines and rail facilities.

5. **Mr. Turton:** As provincial domestic coal consumption has dropped, coal exports have actually risen. Is this the case that the tonnes exported has remained steady, but the percentage has changed due to coal having a smaller piece of the pie, or are coal exports actually increased with consumption based in other jurisdictions? [PA-76]

   Answer:
   The volume of coal exports increased by 6.6 per cent in 2018-2019 compared to the previous year (metallurgical coal exports increase by 9.8 per cent and thermal coal exports increase by 4.7 per cent). The export figures shown in the Annual Report are relative to total coal deliveries, which dropped by 24 per cent

in 2018-2019. The percentage of coal exports to total coal deliveries is therefore higher (19.4 per cent) than the actual growth in coal exports (6.6 per cent).

6. **Mr. Dach:** I wanted to hear from you about the process leading to the full commissioning of the northwest refinery. My understanding is, sir, that one unit, the gasification unit, is the difficulty with the project right now – it's not functioning properly – and that also it was the one unit that was built offshore, the one module of the refinery that was built offshore, and that it was actually mandated to be built offshore, somehow, by contract. Is that the case, that the one unit, the gasification unit that is not functioning properly was actually mandated to be built offshore? [PA-76]

   Answer:
   There is nothing in the contracts, available on the website https://apmc.alberta.ca, which mandated any of the components to be built offshore.

7. **Ms Renaud:** Thanks, Madam Chair. My questions are about oil by rail. I'm wondering if we can get just some perspective about the advice that was given to the previous government to pursue the contract or the work that they did around, you know, increasing capacity to move oil by rail and where we were at this process at the end of the fiscal year, how much money was spent, how much oil had moved, and how had that benefited the economy? [PA-78]

   Answer:
   Advice provided to a previous government is not made available to a current government due to cabinet confidentiality. During the 2018-2019 fiscal year, contracts were signed in February and March for the provision of 120,000 barrels per day of rail capacity. Also during the fiscal year, prepaid expenses of $308 million (1) were made for railway services to Canadian Pacific (CP) Railway and Canadian National (CN) Railway under the Province's Crude by Rail initiative announced in November 2018. The prepayments were a necessary part of the execution of the contracts and resulted in a reduction of future toll charges. A further expense of $6 million (2) for professional, consulting and legal services was incurred during the fiscal year. No oil was transported as part of the crude by rail initiative during the 2018-2019 fiscal year.

   (1) https://open.alberta.ca/dataset/cbd7147b-d304-4e3e-af28-78970c71232c/resource/29d5328f-c689-472a-b69e-9ffe0a3b77ba/download/energy-annual-report-2018-2019-web.pdf (Page 78 of the Annual Report)

   (2) https://open.alberta.ca/dataset/3d732c88-68b0-4328-9e52-5d3273527204/resource/2b82a075-f8c2-4586-a2d8-

3ce8528a24e1/download/Budget-2019-Fiscal-Plan-2019-23.pdf (Page 12 of the Budget document).

8. **Ms Hoffman:** Thank you. A few here. One is around the materiality of preparing the Energy financial statements, so not the materiality for the audit but the materiality for your own financial statements. I'm curious as to what that was set at percentagewise and dollar amount and also what the relationship is between that and the materiality that the OAG set for the actual audit. [PA-78]

   Answer:
   In preparing the Energy financial statements, the department strives to record all accounting transactions accurately. Any discrepancies identified before the accounting records are closed for the year are corrected at the time of identification. Any items identified after the accounting records are closed, such as updated resource revenue amounts, are evaluated and/or discussed with the OAG using professional judgement and the OAG's materiality before adjustments are made.

9. **Ms Hoffman:** My other one is around the AESO and capacity market, so the ministry's relationship in terms of the – I guess I'm interested in what the dollar amounts were, what the supply measures were with regard to the capacity market, and how that may have changed with recent information, so what past documents there were that spoke to that, what the cost estimates were, and what the capacity measures were going to be, again, looking backwards at the past year. [PA-78]

   Answer:
   - The capacity market would not have carried costs to government.
   - The capacity market was to be designed and operated by the Alberta Electric System Operator (AESO), an arms length agency with its own funding mechanisms.
     - AESO operations are funded through the fees it charges to wholesale electricity market participants for exchanging electricity through the power market. The actual costs associated with capacity procurement were to be recovered through the ISO tariff which is charged to electricity market participants that are transmission system connected.

10. **Mr. Feehan:** I have a question just to have you provide any documents or work around the planning for future REPs that has been done for the renewable energy market, what's been done in terms of planning for those things up to this point, and what the parameters are for who can invest and so on. Just information about what work has been done leading toward the future. [PA-78]

Answer:

- In February 2019, the Alberta Electric System Operator was directed to provide recommendations for a Renewable Electricity Program Round 4 to procure up to 400 megawatts of large-scale renewable electricity, building on the minimum 25 per cent Indigenous equity ownership per project required in the Renewable Electricity Program Round 2.
- Also in February 2019, the Government of Alberta announced a road map for the Renewable Electricity Program, including interim targets to achieve 30 per cent renewable electricity by 2030. http://www.qp.alberta.ca/documents/MinOrders/2019/Energy/2019_141_Energy.pdf
- In June 2019, the Minister of Energy advised the Alberta Electric System Operator that the Minister does not intend to proceed with additional rounds of the Renewable Electricity Program. https://www.aeso.ca/assets/Uploads/GoA-REP-32469signed-letter.pdf
- The Minister encouraged the Alberta Electric System Operator to work with the Department of Energy to encourage market-driven renewable generation, without the need for direct subsidies, as part of Alberta's future electricity mix.
- In July 2019, the Government of Alberta also decided to maintain Alberta's energy-only market, rather than creating a capacity market. This decision was made after hosting roundtable sessions with key stakeholders, including renewable generators, and receiving feedback which indicated a preference for the energy-only market design.
- The Government of Alberta is also working on a new Technology Innovation and Emissions Reduction (TIER) system to manage emissions from large industries to encourage energy-intensive facilities to find innovative ways to reduce emissions and invest in clean technologies.

11. **Mr. Dach:** I'd like to ask: as the ministry tracks our combined tax and royalty rate for conventional oil and gas in relation to other jurisdictions, how are we measuring up? I'm wanting to know if indeed we're on the right track. [PA-78]

Answer:

- This comparison was used extensively in the 2015 Royalty Review, and that information and analysis is in the report.
    - This report can be found on the Open Government portal.
    - The analysis in the 2015 Royalty Review has not been updated.
    - The announced Modernized Royalty Framework contemplated annual updating of the proxy cost formula – which has been done.

  - It also contemplated a three-year review of the formula following its implementation in 2017.
- Direct comparisons between Alberta's royalty rates and those in other jurisdictions cannot be made without updating the analysis in the 2015 review.
  - Changing drilling patterns in key resource-producing jurisdictions across North America, including here in Alberta – where new drilling activity is taking place in the Duvernay and Montney plays – makes direct comparisons very challenging without an updated analysis.
  - Royalty systems in other resource producing jurisdictions are different from Alberta's.
  - Alberta's diverse and complex geology is unique, which needs to be taken into consideration when comparing royalty rates.
  - Because Alberta's royalty system is designed for Alberta's diverse geological base and changing drilling patterns, royalty rates are adjusted depending on well productivity, drilling cost and market prices.
- Alberta Treasury Board and Finance does compare Alberta's tax rates with other jurisdictions, but royalties are not included in the comparison: https://www.alberta.ca/alberta-tax-advantage.aspx
- This measure was reviewed in 2015, prior to the 2015 Royalty Review.
  - A decision was made to no longer use this measure.
  - I do not believe there is a public statement as to why that decision was made, nor can I divulge advice or confidences of the Minister.

12. **Mr. Toor:** Page 24 of the annual report contains employment numbers for the Alberta energy industry. Like capital investment, employment in the sector is down from 2014. Direct employment appears to be down from 28,000. Can you explain the connection, if any, between the decline in capital investment and investor confidence and the job losses in our energy sector since 2014? [PA-78]

Answer:
The decline in capital investment in the oil and gas sector since 2014 was largely driven by the sharp pullback in global oil prices. West Texas Intermediate (WTI), the benchmark North American crude, fell from an average of about US$93 per barrel in 2014 to US$43 per barrel in 2016. Although WTI improved in the succeeding two years, averaging US$51 and US$65 per barrel in 2017 and 2018, respectively, it is nowhere near the levels we saw in 2014. In addition, while the improvement in prices in 2017 and 2018 led to a rebound in drilling activity in the province, oil sands investment remained weak as costs have come down sharply – and because the last of the major projects that broke ground prior to 2015 wound down construction. Severe pipeline bottlenecks and rising inventories also led to unprecedented discounts for Alberta crudes in late 2018 and a sharp slowdown in drilling activity towards the end of the year.

The 2014 decline in oil prices had a major impact on employment in Alberta's mining, quarrying and oil and gas extraction sector. Between 2014 and 2016, direct employment in this sector in Alberta declined by about 23 per cent, from 175,000 to 136,000 people. However, in 2017, employment in the upstream energy sector increased by three per cent from the 2016 level to 140,000 people. From 2017 to 2018, employment in this sector went up by a further five per cent to 147,000 people. This is directly related to the declines in investment in the sector as Alberta experience a significant decline in investment since 2014 and, despite a slow recovery, it has remained below 2014 levels.

In addition to declining crude oil prices, a lack of sufficient market access also contributed to a decline in capital spending in Alberta, as several expansion projects have been cancelled or postponed. Federal government policies, such as Bill-C69 and Bill C-48, have also contributed.

It should be noted, however, that investor confidence in the energy sector has eroded throughout the world, and not just here in Alberta. This is due to rising concerns about climate change.

13. **Mr. Toor:** Second, page 24 references direct job losses from 2014 but does not reference indirect job losses since 2014. How do indirect employment numbers from 2014 compare to 2018? Is this number readily available from the department at this time? [PA-78]

Answer:
The 2014 indirect employment result that can be consistently compared with the 2015-2018 results presented in the 2018-2019 Annual Report is not available.

Alberta Energy used Statistics Canada's multiplier to calculate indirect employment in the 2018-19 Annual Report. Indirect employment numbers in the Annual Report were provided for the 2015-2018 period, as the 2015 multiplier cannot be used to estimate pre-2015 indirect employment. All indirect results for the 2015-2018 period are based on a constant ratio, so the direct and indirect employment results increase and decrease at the same rate year-over-year during this period.

The previous, 2017-18 Annual Report presented indirect employment in the Mining, Quarrying, and Oil and Gas Extraction sector for the 2013-2017 period. However, these results were based on an outdated multiplier. The indirect employment result reported in that document for 2014 should not be compared with the 2018 result in the 2018-19 Annual Report.

14. **Mr. Toor:** Next, I appreciate that a driving factor for the capital investment is the accommodating prices as indicated on page 22 of the annual report, but as discussed, investor confidence across the jurisdiction is not equal and is

impacted by many factors. What other factors do you believe may have led to the flight of billions of dollars in foreign direct investment other than the price of commodities? [PA-78]

Answer:
Regulatory delays surrounding export pipeline approvals have affected market access for commodities, uncertainty about federal environmental policies, and a better economic climate for U.S. shale development, among others factors, have contributed to the decline.

15. **Mr. Toor:** Next, page 22 not only indicates that the annual investment in Alberta in total dollars; it indicates Alberta's share of Canadian investment. Alberta's share of Canadian investment declined from 67 per cent to 58 per cent in 2017, the last verified year from Statistics Canada. What key factors would you identify in Alberta's relative decline in investment attraction from 2015 to 2017? [PA-78]

Answer:
The energy sector is an important component of Alberta's investment levels. Since most of the investment decline came from the energy sector after the oil price collapse in 2014, total investment levels in the province declined. Further delays on reaching full market access and better economic conditions in the U.S. on shale development have contributed to Alberta's investment decline.

Alberta accounted for an absolute majority of total capital expenditures in the Canadian Mining, Quarrying, and Oil Extraction Sector during the entire examined period. Alberta still attracts significantly more upstream energy investment that other Canadian jurisdictions. The estimated investment in 2018 in Newfoundland and Labrador, Saskatchewan and British Columbia in this sector was also lower than in 2014.

16. Mr. Nixon: Page 64 of the annual highlights table. Under bonuses and sales of Crown leases revenue from bonuses and sales has declined $200 million. Can the department explain the decline? Is it related to the decline in investor confidence? Additionally, on page 64 the average price per hectare has declined from $415 to $271. Can you explain the significant decline and its causes for the committee? [PA-78]

Answer:
The lack of full market access and the impact of 2014 price collapse has weighed on oil and gas investment in the province. This has showed in provincial land sales over the last few years, as companies have pulled back on their exploration activities.

Crown leases revenue from bonuses and sales are generated through a transparent process and competitive bid auction. Quality and geology of parcel of lands sold are major factors in determining the average price per hectare, among other factors. In each year, companies' strategies in terms of growing production or keeping the production the same is of high importance as well. For example, companies adopting production growth strategies might think of acquiring more lands. Delivering crude to international market and limited market access are the main challenges faced by companies for growing production. Without additional pipelines, there will be limited production growth opportunities, as all the export pipelines are currently full. That being said, lack of interest or lower interest in Crown lands could drive down the price per hectare. Lower commodity prices, lack of market access and very limited growth opportunities, all results in lower investor confidence and lower Crown land price per hectare.

17. **Mr. Gotfried:** My question is that I understand the government of Alberta is liable to cover for surface leases for unpaid leases, particularly on grazing lease land and perhaps also on freehold lands. Could you please quantify annual payments or liabilities in this regard for fiscal 2018-29 and for the past three to four years for comparison if those figures are available? [PA-78]

    Answer:
    This area is the responsibility of Alberta Environment and Parks.

18. **Mr. Stephan:** How can we see grandfathering for coal plants to the end of their economic life to mitigate hundreds of millions of coal phase-out compensation payments to plant owners? [PA-78]

    Answer:
    - Under federal and provincial policy, six of Alberta's 18 coal-fired plants are slated to end operations by 2030, prior to the end of their economic lives. Both sets of policies independently drive to this outcome.
    - Consequently, extending the life of coal-fired operations beyond 2030 requires action at both provincial and federal levels, and would require the federal government to have an interest in altering its policy.
    - Grandfathering the plants will also require cooperation from the coal-fired generators, which are currently more focused on coal-to-gas conversions rather than the extension of coal-fired power operations.
    - On the provincial side, Alberta's coal phase-out is not legislated, but is instead enshrined in contracts – the Off-Coal Agreements. In light of this, Alberta could engage the impacted coal-fired generation plant owners to negotiate an amendment or end to these contracts.

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