



## UPDATE: A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry

September, 2018

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and oil. CAPP's associate members provide a wide range of services that support the upstream oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about \$110 billion a year. CAPP's mission, on behalf of the Canadian upstream oil and natural gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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2100, 350 – 7 Avenue S.W.  
Calgary, Alberta  
Canada T2P 3N9  
Tel 403-267-1100  
Fax 403-261-4622

1000, 275 Slater Street  
Ottawa, Ontario  
Canada K1P 5H9  
Tel 613-288-2126  
Fax 613- 236-4280

1004, 235 Water Street  
St. John's, Newfoundland and Labrador  
Canada A1C 1B6  
Tel 709-724-4200  
Fax 709-724-4225

360B Harbour Road  
Victoria, British Columbia  
Canada V9A 3S1  
Tel 778-265-3819  
Fax 403-261-4622

## Executive Summary

Global energy demand is on the rise and the world will need more energy in all forms, including oil and natural gas. The Canadian energy industry has a long history of innovation and technological advancements that have improved efficiency and environmental performance, while growing production. Canada has an opportunity to become the world's preferred energy supplier, generating economic benefits and minimizing the environmental impacts at home and around the world.

In order for Alberta to take advantage of this opportunity, it is imperative the province is able to compete on the global stage. This is important as the oil and natural gas industry has faced significant hurdles to development in recent years, none more challenging than the struggle to maintain competitiveness and attract international investment.

At a time when both global energy demand and oil and natural gas investment are on the rise around the world, investment in Canada's upstream oil and natural gas industry is expected to decline. Unconventional oil and natural gas investment is expected to be flat at best, with comparable investment in the United States increasing by approximately 15 per cent. While long-cycle upstream spending is expected to increase globally, total annual spending in the oil sands is expected to decrease for a fourth consecutive year. This has negatively impacted employment and government revenues in Alberta.

- Alberta's net non-renewable resource revenues have declined to \$3 billion in 2016-2017 from approximately \$9 billion in 2014-2015.
- Private sector employment remains 84,000 employees below the fourth-quarter 2014 average of more than 1.5 billion.
- The average unemployed Albertan has been unemployed for more than 40 per cent of a year, which is higher than the peak unemployment duration in the aftermath of the 2007-2008 financial crisis.

For several years investor confidence in Canada's oil and natural gas industry has eroded and continues to remain low due to a number of factors:

- Market dynamics and commodity price trends;
- Market access challenges;
- Regulatory complexity and uncertainty;
- Fiscal policy, including tax reforms in the U.S.; and,
- The rising cost of doing business in Canada, including regulatory costs.

Increased market access has been key in industry's strategy to close the competitiveness gap, but it is not sufficient in and of itself. There is still a need for improvements to regulatory efficiency and certainty, effective implementation of climate policies that mitigate trade exposure and encourage innovation, strengthened fiscal terms, and a decline in resource access risk.

In 2017, the Canadian Association of Petroleum Producers (CAPP) identified the challenges facing Alberta's upstream oil and natural gas sector in its report, *A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*.<sup>1</sup> CAPP proposed solutions to working collaboratively with the Government of Alberta (GoA) to improve the investment climate.

Now, one year later, CAPP is providing an update on the status of Alberta's investment climate and its competitiveness – identifying areas of improvement, as well as opportunities for further prioritization with government.

## Vision

There is an opportunity for the GoA to take a leadership role in defining the province's vision for future development. Alberta needs a stable and efficient regulatory system and competitive fiscal structure, while maintaining environmental policy to position **the province as a supplier of choice in meeting the world's growing energy needs.**

## Oil and Natural Gas Competitiveness as an Alberta Priority

In 2017, CAPP recommended the province adopt a “whole of government” approach to strengthen Alberta's investment attractiveness while achieving policy objectives. Government needs to build on its recognition of the important role competitiveness plays in the energy sector, continuing to make a more concerted effort towards improvement.

CAPP encourages the government to address industry competitiveness. In order to ensure long-term viability and success, CAPP recommends the province:

- Adopt the above-mentioned vision for future development, complete with specific goals and performance metrics relating to the health of the industry, including investment, production, and project approval-related targets (e.g., pipelines, investment and share of global supply).
- Require all ministries meeting with the oil and natural gas sector to adopt a mandate to improve competitiveness as a key consideration in their decision-making processes, and work with industry accordingly.

This vision should be supported through a co-ordinated effort with industry, government, and individual Albertans, to create an effective policy and regulatory environment that encourages investment in Alberta's oil and natural gas resources, and ensures they are produced responsibly.

## Market Access

The GoA have championed the need to expand market access by advocating for the Trans Mountain Expansion Pipeline (TMEP). However, the recent Federal Court of Appeal's decision on TMEP is further evidence Canada's regulatory system is creating uncertainty for industry and

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<sup>1</sup> CAPP, *A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*, 2017. <https://www.capp.ca/publications-and-statistics/publications/304673>

investors. It highlights the need for the GoA to continue championing the need to expand market access for the oil and natural gas industry.

CAPP recommends the Alberta government reinforce its support for liquefied natural gas (LNG) development on Canada's West Coast, with a comparable level of commitment to its efforts on TMEP. CAPP also recommends that the province actively support industry in its call for the pause and review of federal Bills C-69 (Canadian Environmental Assessment Agency and National Energy Board [NEB] review) and the elimination of C-48 (West Coast Tanker Moratorium) in light of the Federal Court of Appeal's decision on TMEP. There is an opportunity for the Alberta government and industry to send a strong and firm message to the Government of Canada (GoC) and stand up for Alberta.

Improved market access for both oil sands and unconventional oil and natural gas is a key factor driving industry competitiveness. However, as the modelling demonstrates, increased market access in and of itself is not enough to address Canada's competitiveness challenges. Both federal and provincial governments have a role to play in addressing the cumulative policy and regulatory impacts that, in aggregate, make Alberta less competitive relative to other jurisdictions, thereby discouraging investment and, with it, negatively impacting jobs and government revenues.

## **Regulatory Competitiveness**

Alberta has some of the highest standards yet one of the most complex environmental and regulatory regimes in the world. The current regulatory environment has contributed to the erosion of investor confidence in the oil and natural gas industry. Alberta's regulatory framework is challenged by process inefficiencies, lengthy approval timelines, and escalating regulatory costs that, combined, increase costs and generate investor uncertainty in Alberta's regulatory system.

One of the most significant opportunities is enabling a more efficient and predictable regulatory process, which would help achieve industry competitiveness while maintaining environmental and regulatory outcomes. The Alberta Energy Regulator (AER), with the support of the province, is working with the industry – a regulated community held to higher standards than other stakeholders – to identify opportunities to improve regulatory certainty. CAPP supports government efforts to set and achieve clear performance metrics, and focus resources in priority areas, and ensure progress towards improved outcomes.

Routine applications in Alberta are generally approved within relatively reasonable timeframes, but there is significant variability in approval timelines for simple applications such as wells or facilities that are non-routine due to participant engagement. For example:

- The proportion of well and facility applications that are non-routine due to participant engagement has nearly doubled since 2014.
- These non-routine participant involvement (PI) well licences take can take 10 times as long as routine well licence applications.
- Facility licence applications that are non-routine PI can take as long as 130 days to approve.

These considerations are foundational drivers of risk and uncertainty for investors, and a key limiter in advancing project development. This uncertainty is compounded by the requirement for multiple approvals, licences and permits to enable a project to proceed (more than 560 are required for in situ developments), each of which has associated uncertainty with respect to approval timelines, and may be required to be obtained in sequence.

CAPP recommends the AER continues to work with industry to substantially streamline the regulatory approval process. Key opportunities to increase regulatory certainty include:

- Advancing efficiency priorities such as:
  - Improving application timelines and streamlining the Statement of Concern (SOC) process,
  - Harmonizing the Aboriginal Consultation Office (ACO) and AER consultation processes,
  - Adopting a Project Area Disposition (PAD) approach,
  - Fully implementing Area-Based Closure (ABC) programs,
  - Completing execution of the Integrated Decision Approach (IDA), and
  - Ensuring subsurface regulatory reform through modernization of requirements;
- Streamlining the regulatory process for activity within previously approved oil sands project boundaries by relying on the rigour of the original project approvals;
- Collecting data and benchmarking performance for Alberta (with a particular focus on reducing overall timelines as well as the variation within timelines) and comparable jurisdictions;
- Integrating and streamlining processes with other provincial ministries such as Alberta Indigenous Relations (IR) and Alberta Environment and Parks (AEP); and,
- Modernizing regulations to remain current with technological developments, and eliminate unnecessary or obsolete requirements.

## Climate Policy

The Canadian oil and natural gas industry supports effective and efficient climate policies that take cumulative costs into account.

It is crucial that any climate policies are well implemented in order to ensure they do not further hinder competitiveness. CAPP recommends the province implement climate policies with protection mechanisms for energy-intensive, trade-exposed (EITE) sectors, and re-invest any carbon-related revenue into EITE industries through revenue recycling and innovation funding. CAPP further recommends the province actively work with industry to advocate the federal government for appropriate EITE protection for aggregate climate compliance costs (including methane, carbon pricing and clean fuel standard [CFS]).

## Fiscal and Economic Policy

A globally competitive fiscal framework encourages innovation, and positions Alberta's oil and natural gas as the world's energy supplier of choice. In 2015 the GoA increased the corporate income tax rate to 12 per cent from 10 per cent. The combined federal and provincial corporate

income rate for Alberta is 27 per cent. In contrast, recent tax reform in the U.S. has caused Canada's fiscal framework to fall behind on key factors with respect to tax policy. The average U.S. combined federal and state corporate income tax rate is now 25.75 per cent.<sup>2</sup> Texas, which draws the bulk of U.S. oil and natural gas investment, has zero corporate tax rate therefore companies only pay a federal rate of 21 per cent.

CAPP recommends the province work with industry to advocate to the federal government for 100 per cent immediate deductibility of capital expenditures, in a manner similar to the U.S. tax reforms.

The GoA deserves credit for its efforts on advancing value-add in the province. More work is needed to encourage innovation and competitiveness through reforms to oil sands royalty valuation, enforcing municipal tax rate ratios, and returning corporate income tax rates to previous levels.

## **Resource Access**

Alberta's environmental standards ensure the province's resources are responsibly developed. The government needs to ensure industry has access to resources, implements policies that limit risks to resource access – potentially avoiding jeopardizing the economic viability of potential investments, and eliminates duplicative or contradictory policies.

Issues such as caribou range planning, lease tenure policy, and land-use planning all create some level of risk in terms of industry's ability to access the resource.

## **Benefits of Action**

The benefits of governments (both federal and provincial) addressing all these issues could be extraordinary. Industry-led modelling suggests the following national benefits: \$20 billion per year of incremental investment; approximately 120,000 additional ongoing jobs (70,000 for liquids-rich natural gas [LRNG] and 50,000 for oil sands); production growth of 50 per cent for LRNG, and 40 per cent for oil sands (or 25 per cent growth above CAPP's current oil sands production forecast); natural gas production growth achieved with greenhouse gas (GHG) emissions intensity declining and GHG emissions essentially flat; and a 20 per cent to 25 per cent decline in oil sands GHG emissions intensity by 2030.

## **Conclusion**

CAPP encourages the province to recognize the importance of Alberta's oil and natural gas industry and its global competitiveness. The government needs to ensure a competitive future for oil and natural gas development. CAPP recommends the province continue building on its commitment to enhance competitiveness with strong and overt leadership, with a corresponding commitment to specific outcomes, targets, timelines, and performance metrics.

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<sup>2</sup> Grant Thornton, Tax reform is finally here. What do we do now? 2018.

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# 1 Introduction

CAPP represents companies, large and small, that explore for, develop and produce oil and natural gas throughout Canada. CAPP's member companies produce about 80 per cent of Canada's oil and natural gas. CAPP's associate members provide a wide range of services that support the upstream oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about \$110 billion per year.

From a competitiveness perspective, the upstream oil and natural gas industry is currently confronted with significant challenges and risks from a competitiveness perspective, particularly in a North American context. These challenges have the potential to further diminish Canada's and Alberta's ability to attract investment and generate employment, and the economic and government revenue benefits associated with developing our resources responsibly.

Competitiveness challenges facing the industry were identified in CAPP's previous report, *A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry*. This report seeks to provide an update of Alberta's competitiveness position, and offer recommendations to improve competitiveness while maintaining environmental, social and regulatory outcomes.

## 2 Competitiveness Context: Investment Climate

With Canada's high-quality, world-class resources, environmental leadership, and the most robust regulatory regime in the world, Alberta should be the global supplier of choice to meet increasing future energy demand.

For a number of reasons, including market dynamics and commodity price trends, regulatory complexity and uncertainty, market access challenges, tax policy (including U.S. tax reforms) and the rising cost of doing business (including regulatory costs), Canada's oil and natural gas sector has experienced reduced investor confidence over the past several years. Market conditions and cost issues unique to the Canadian oil and natural gas sector have played a role in this shift in competitiveness. However, government policy and regulatory actions have also been a factor in diminishing Alberta's, and Canada's, competitive position relative to competing jurisdictions. There is increasing momentum toward migration of investment capital to other jurisdictions, and once established this negative momentum is difficult and time-consuming to reverse.

Upstream oil and natural gas investment in Canada is expected to decline in 2018, at a time when global energy demand and upstream investment is projected to rise. Recent investment trends are reflected in the charts below.



### Production

**FIFTH** largest global producer of natural gas.

**SIXTH** largest global producer of oil.



### Economy

**533,000 CANADIAN JOBS**

(direct and indirect) in 2017

**\$109 BILLION** in direct real GDP in 2017, 6.25% of Canada's total GDP.



**\$110 BILLION/YEAR** in average annual revenue (2014-2016).

**\$12 BILLION/YEAR** in average annual revenue to governments

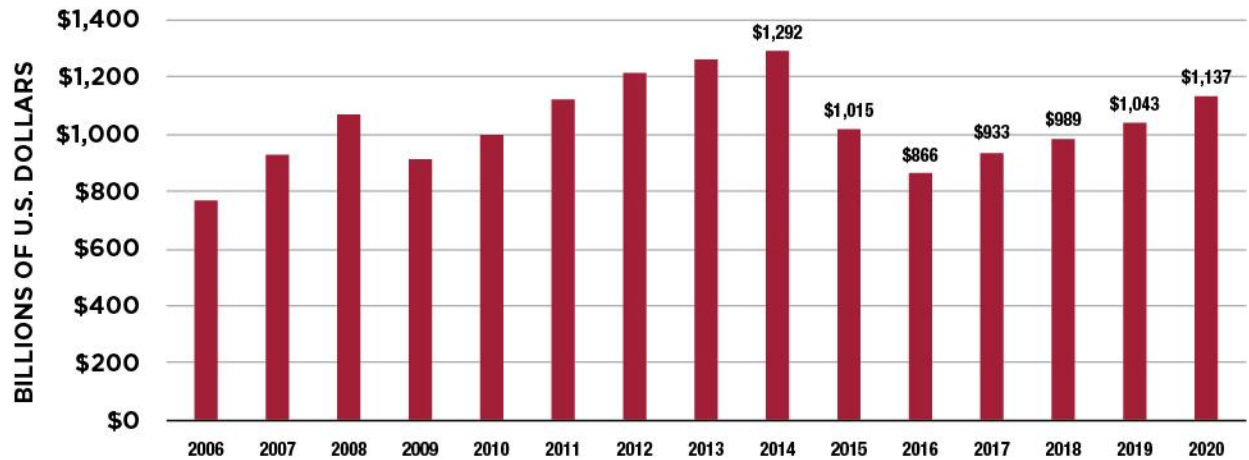


### Indigenous Participation

**\$75 MILLION** in annual payments to Indigenous governments.

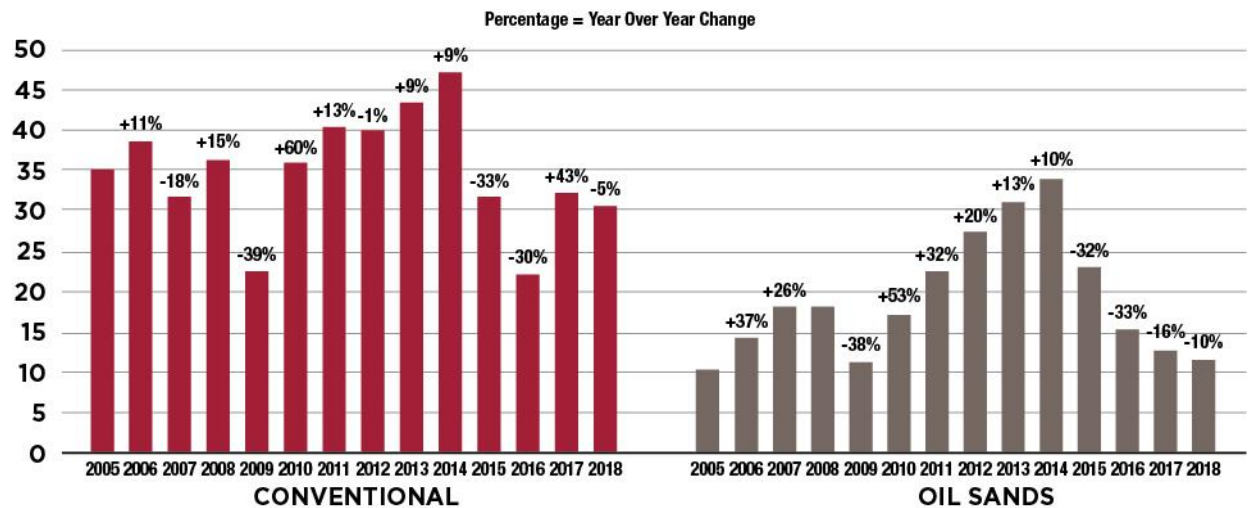
**\$3 BILLION IN PRODUCTS AND SERVICES** purchased from Indigenous businesses in 2015-2016 and contributed **\$50 MILLION** to Indigenous communities (oil sands only).

**Figure 1: Summary of Upstream Global Spending**



SOURCE: IHS Market Global Upstream Spending; November 27, 2017

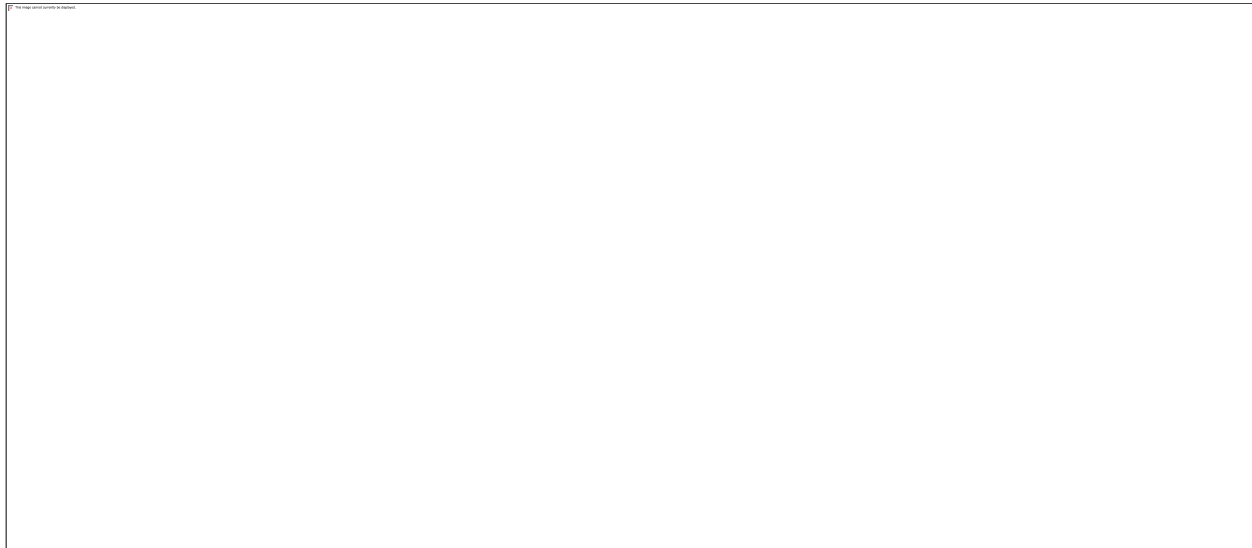
**Figure 2: Upstream Capital Investment in Alberta**



SOURCE: CAPP

While global long-cycle spending as a proportion of total upstream investment continues to be on the rise, the proportion of oil sands spending is on the decline, with total annual spending expected to decrease for a fourth consecutive year (see Figure 3).

**Figure 3: Global Long Cycle Spending<sup>3</sup> Shifting Away from Oil Sands**



Smaller oil and natural gas firms face the same competitiveness challenges as those faced by larger firms. However, their ability to mitigate these challenges is limited as smaller firms struggle to finance growth. Access to capital has all but disappeared for junior exploration and production companies as the number of small/intermediate public companies has dropped about 50 per cent since 2012.<sup>4</sup>

Exacerbating Canada's competitiveness challenges are the recently enacted U.S. tax reforms – making it harder for Canada to attract investment by comparison. In addition, as part of its North American Free Trade Agreement (NAFTA) negotiations, the U.S. has issued tariffs on Canada that potentially further threaten our competitiveness.

It is a critical time for government and industry to align on a strategic long-term vision for the oil and natural gas industry. Ensuring that Canada becomes competitive would re-establish the investor confidence required to attract the capital to sustainably grow the industry and economy. The oil and natural gas industry is of the view that there is a near-term imperative for collective actions by industry and governments to address significant and systemic competitiveness gaps.

**“Access to capital has all but disappeared for junior exploration and production companies as the number of small/intermediate public companies has dropped about 50 per cent since 2012.”**

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<sup>3</sup> Rystad's definition of global upstream spending includes capital expenditures associated with wells, facilities, exploration, and abandonment, as well as operating expenses associated with taxes, selling, general & administrative expenses (SG&A), transportation, and production.

<sup>4</sup> National Bank, Financial Markets, 2018.

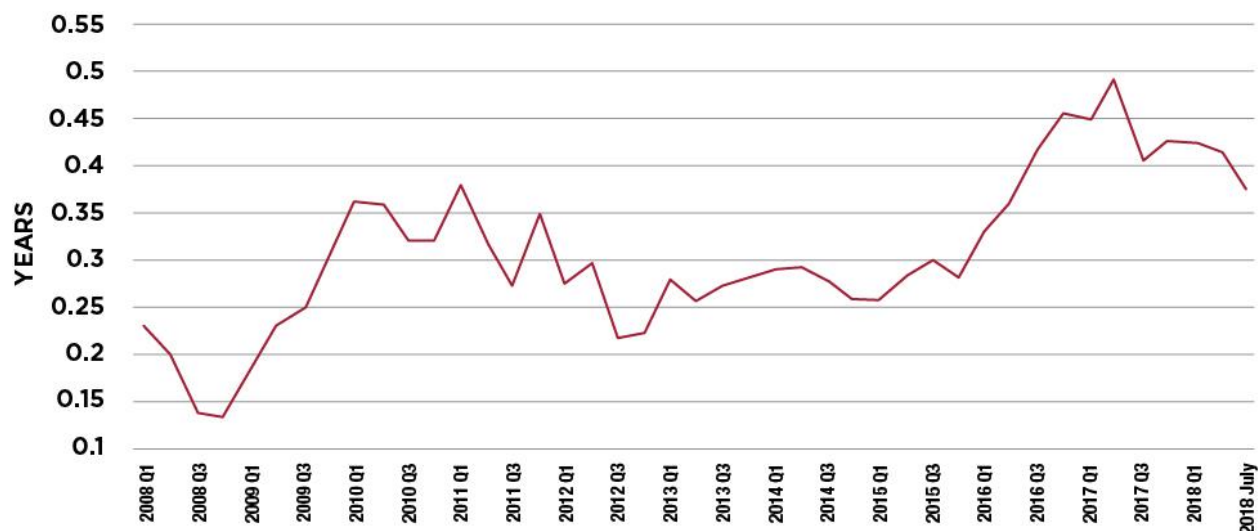
## Impacts on Employment

The oil and natural gas industry generates activity which spurs job and economic growth across the country. For example, the investments in the energy industry supported and created more than 640,000 direct and indirect jobs across the country in 2015, and 533,000 jobs in 2017.

The increased competitiveness challenges pose significant risk for Alberta workers. The province's labour force is still suffering from the 2014-2015 commodity price crash. Although economic and jobs growth are rebounding, concerning trends in Alberta's labour market continue. Private sector employment has not fully recovered, forcing more Albertans to seek alternative means of employment. As of July 2018, private sector employment remains 84,000 employees below the 2014 fourth-quarter average of more than 1.5 billion (see appendix).

Moreover, during the last half of 2016 and first half of 2018, the average unemployed worker in Alberta has been unemployed for more than 40 per cent of a year (Figure 4). This is higher than the peak unemployment duration reached in Alberta in the aftermath of the 2007-2008 financial crisis. Research shows that workers unemployed for longer periods of time are more likely to earn permanently lower wages if they re-enter the workforce and are less likely to be re-employed.<sup>5</sup>

**Figure 4: Alberta Average Duration of Unemployment in Years, Unadjusted for Seasonality**



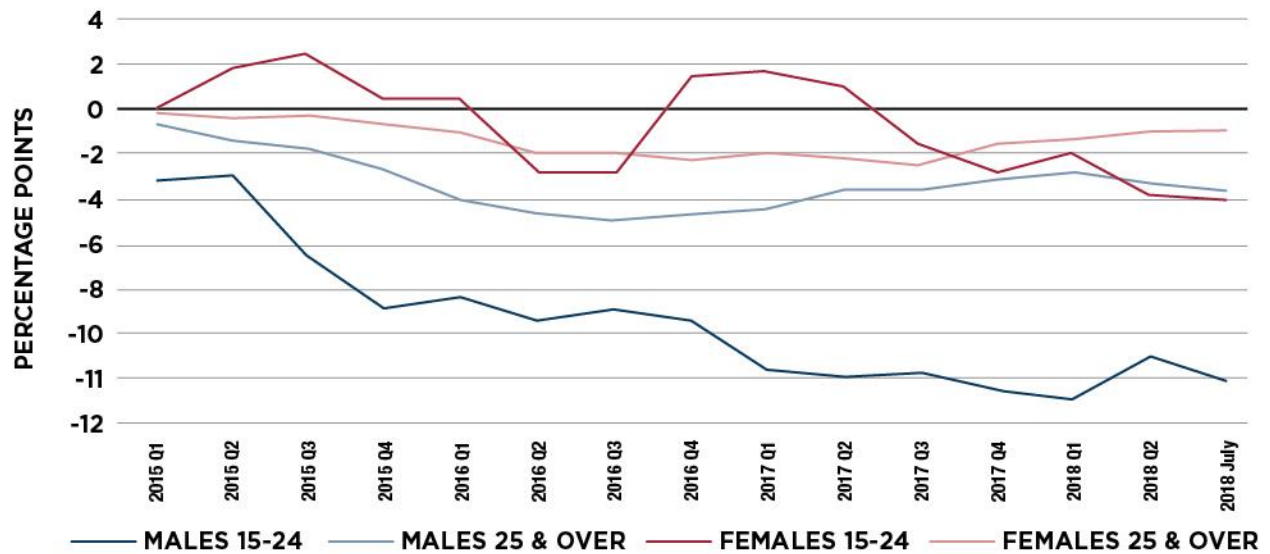
SOURCE: Statistics Canada, Table 14-10-0056-01

While the average unemployment duration has been falling since the second quarter of 2017, not all of that is attributable to unemployed workers finding work, but can be partially attributed to people dropping out of the labour force. This is reflected in Figure 5, which shows that employment rates remain below their fourth quarter 2014 average across a variety of demographic characteristics. The

<sup>5</sup> Zmitrowicz, Konrad, Khan, Mikael, "Beyond the Unemployment Rate: Assessing Canadian and U.S. Labour Markets Since the Great Recession," Bank of Canada Review, 2014. <https://www.bankofcanada.ca/wp-content/uploads/2014/05/boc-review-spring14-zmitrowicz.pdf>

employment rates for young men in particular remain severely depressed as of July 2018 at 10 percentage points below the fourth quarter 2014 average.

**Figure 5: Change in Alberta Employment Rate since Q4 2014 by Sex and Age Group, Seasonally Adjusted**



SOURCE: Statistics Canada, Table 14-10-0287-01

### **3 Policy and Regulatory Challenges Confronting Canada's Upstream Oil and Natural Gas Industry**

While the U.S. is reducing costs and streamlining regulations, in some areas Alberta is moving in new policy directions that have the potential to increase costs and reduce competitiveness. CAPP recognizes the importance of developing Canada's resources in a responsible manner to help achieve key regulatory, social and environmental outcomes. However, it is important to do so in a manner that does not unnecessarily impact industry's competitiveness. In fact, CAPP notes that a number of policy and regulatory issues currently being advanced continue to have the potential to adversely impact the industry.

#### **Market Access**

A key factor in the oil and natural gas sector's ability to attract investment and create economic growth and jobs, is access to more customers in growing markets. Improved market access for both oil sands and unconventional oil and natural gas is a key factor driving industry competitiveness. The recent Federal Court of Appeal decision on the TMEP further exacerbates the importance of market access and the challenges confronted by government and industry in advancing this objective.

#### **Regulatory Competitiveness**

Alberta has some of the highest standards and yet one of the most complex environmental and regulatory regimes in the world.<sup>6</sup> The current regulatory environment has contributed to the erosion of investor confidence in the oil and natural gas industry. Alberta's regulatory framework is challenged by process inefficiencies, lengthy approval timelines, and escalating regulatory costs that, combined, increase costs and generate investor uncertainty in the province's regulatory system.

#### **Climate Policy**

CAPP supports climate policies that are effective and efficient and take cumulative costs into account. Any climate policies advanced by government should not hinder competitiveness. CAPP recommends implementing policies with protection mechanisms for EITE sectors, and re-invest any carbon-related revenue into EITE industries through revenue recycling and innovation funding.

CAPP further recommends the province work with industry to advocate to the federal government for appropriate EITE protection for aggregate climate compliance costs including methane, carbon pricing and CFS – all of which need to be developed in a manner that takes into consideration industry concerns.

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<sup>6</sup> Worley Parsons, An International Comparison of Leading Oil and Natural Gas Producing Regions: Stringency, Transparency and Compliance, 2014.



## **Fiscal and Economic Policy**

A fiscal framework that is competitive on the global stage, encourages innovation, and achieves the GoA's vision of making Alberta oil and natural gas the global fuel of choice.

In light of tax reforms in the U.S., Canada's fiscal framework is now trailing the U.S. on key factors where it used to benefit from an overall advantage with respect to tax policy. In 2015 the GoA increased the corporate income tax rate to 12 per cent from 10 per cent, making the province's combined federal and provincial corporate income rate 27 per cent. In contrast, the average U.S. combined federal and state corporate income tax rate is now 25.75 per cent.<sup>7</sup> Texas, which draws the bulk of U.S. oil and natural gas investment, has zero corporate tax rate therefore companies only pay a federal rate of 21 per cent.

CAPP recommends the province work with industry to advocate to the federal government for 100 per cent immediate deductibility of capital expenditures, in a manner similar to the U.S. tax reforms. The GoA can also play a role in establishing fiscal terms that remove inequities and encourage investment in environmental performance and value-add technologies.

## **Resource Access**

Alberta's world-leading environmental standards ensure resources are responsibly developed. In order to facilitate future development, the government needs to ensure industry has access to resources and implements policies in a manner that limits risks, which in turn could jeopardize the economic viability of potential investments.

Current policies and plans under consideration such as caribou range planning, lease tenure, and land-use planning have the potential to add uncertainty and delay to industry's access and ability to develop the resource.

## **3.1 Quantifying Policy and Regulatory Competitiveness Impacts**

CAPP has modelled the cumulative impacts of various government policy and regulatory initiatives using an internal rate of return (IRR) analysis. IRR, expressed as a percentage (%), remains a key indicator of overall investment attractiveness for the oil and natural gas sector. The IRR is a discount rate at which a project's net present value (NPV) equals zero. If the IRR is higher than a company's cost of capital (equity and debt), then a project will add economic value. The IRR analysis is also useful when comparing across jurisdictions, as it provides a useful rationale to understand why a company would choose to invest in another jurisdictions despite what would otherwise appear to be favourable IRRs.<sup>8</sup>

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<sup>7</sup> Grant Thornton, Tax reform is finally here. What do we do now? 2018.

<sup>8</sup> All analysis draws from Wood Mackenzie models and datasets, which have been validated and calibrated independently by CAPP members. All unconventional oil and natural gas modelling was modelled at half cycle. For specifics see the note in the appendix in the section entitled "Notes Accompanying the Economic Modelling." The analysis on data coming from Wood Mackenzie GEM is solely post-final investment decision (FID), so cannot be considered truly full cycle.

### 3.1.1 Economic Modeling Methodology

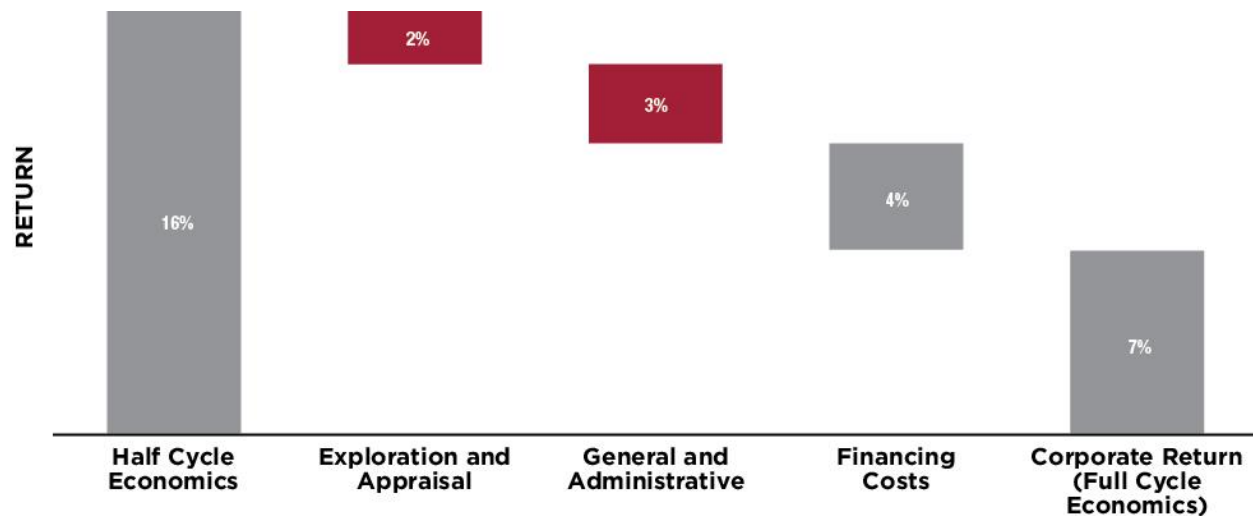
Economics included in this report are intended to reflect development economics (“half-cycle”), as opposed to fully-burdened (“full-cycle”) economics. This approach was taken to ease comparison between jurisdictions and to exclude impacts of corporate structure, which vary by company. In order to interpret the results correctly, it is important to identify which costs are reflected within the following analysis. Please refer to Appendix (A2 Modelling) for a more fulsome explanation of economic modelling assumptions.

Included in the analysis are the costs associated with drilling and completing wells, pads and facilities, as well as associated capital and operating costs required to transport and process the liquid and gaseous products. Excluded from the play analysis are:

- Exploration and Appraisal (land purchase, seismic, delineation, etc.)
- General and Administrative (G&A) (office costs, corporate insurance, salaried office employees, etc.)
- Costs of corporate financing (costs of debt and/or equity, etc.)

The chart immediately below demonstrates the impact to a representative half-cycle IRR when including these additional full cycle corporate costs, and highlights the true return to a company once all these costs have been accounted for. A company’s half-cycle 16 per cent return is reduced to seven per cent when accounting for these additional full-cycle costs.

**Figure 6: Example of Corporate Cost Layering of Half-Cycle Economics**



SOURCE: CAPP

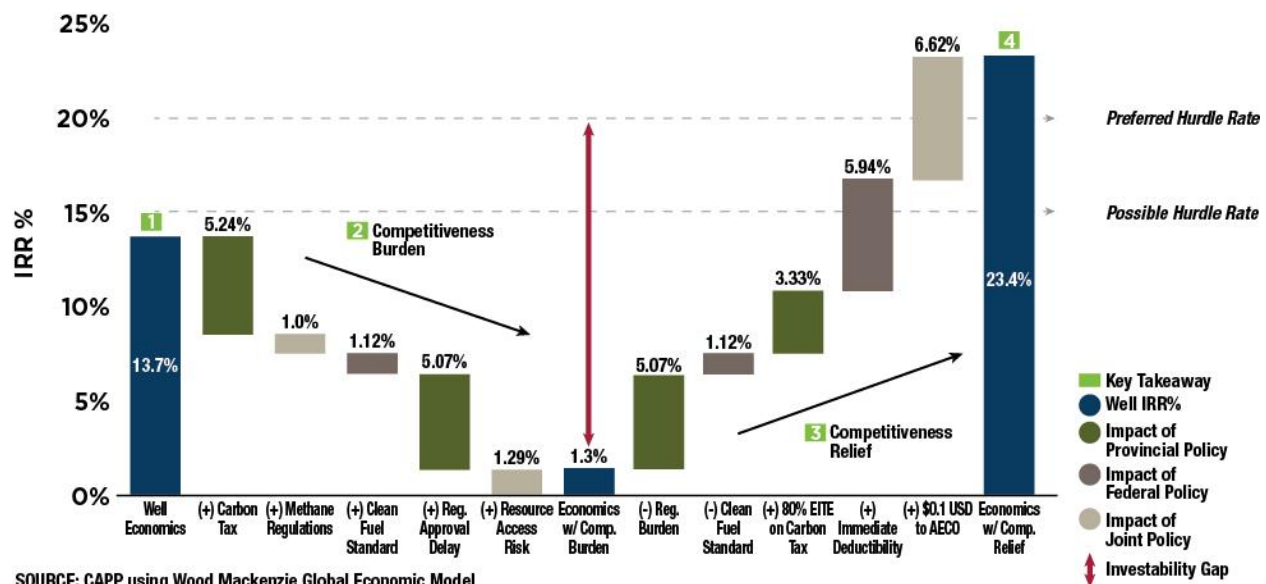
Half-cycle economics are important as companies are all structured differently with differing levels of debt and equity and account for full-cycle costs slightly differently. Financial analysts typically opt to compare wells to one another using half-cycle economics to get a more representative comparisons.

### 3.1.2 Unconventional Oil and Natural Gas

Unconventional oil and natural gas resources are found across North America and on both sides of the Canada-U.S. border. This allows for the comparison and benchmarking of wells in Alberta with comparable wells in the U.S. from the Permian (Texas) and Marcellus (Pennsylvania) plays. These wells share similar estimated recoverable resources and are used for comparison.

Companies need to recover their cost of capital, as well as generate a return for their investors. To do this, companies will set a hurdle rate (the rate of return that is acceptable for a project to proceed). A typical hurdle rate for many operators is 20 per cent, an illustrative 15 per cent and 20 per cent hurdle rate is demonstrated in the following charts. The 15 per cent shown is generally the minimum rate at which a company will invest. However, projects of 20 per cent and higher are viewed as preferred investments and more likely to attract investment capital. A half-cycle analysis does not include any costs related to land acquisition, exploration, appraisal, among others, nor do they include any G&A. If these were taken into consideration, the targeted IRR would be substantially lower.

**Figure 7: IRR Waterfall—Deep Basin Spirit River Well (Dry Natural Gas)**



SOURCE: CAPP using Wood Mackenzie Global Economic Model

Figure 8: IRR Waterfall—Montney Elmworth Karr Well (Wet Natural Gas)

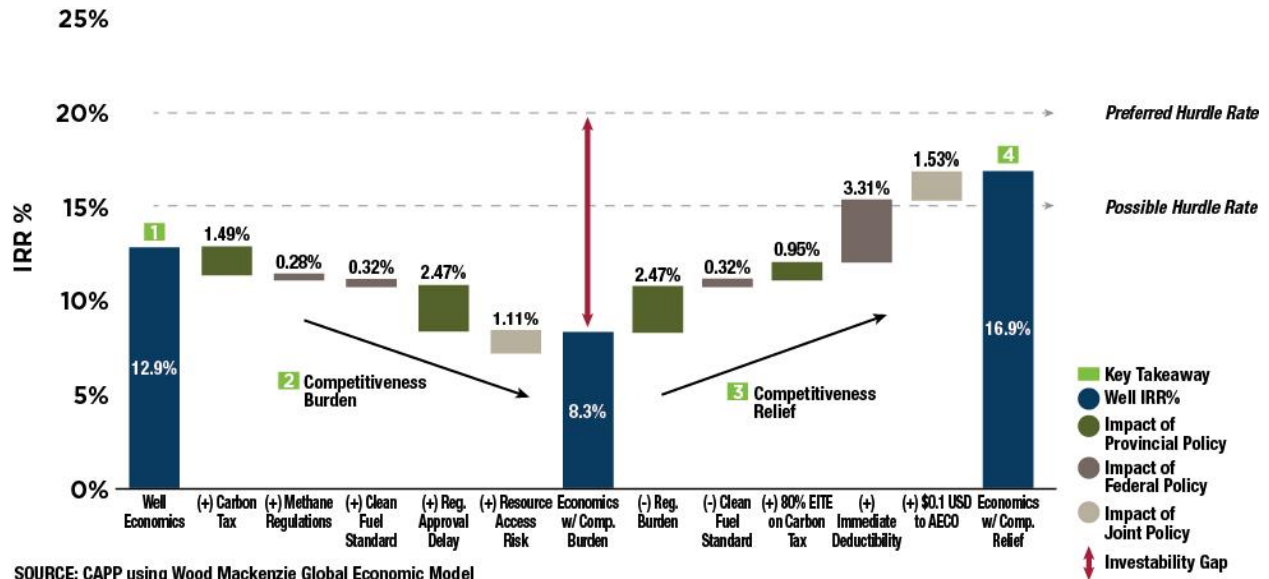
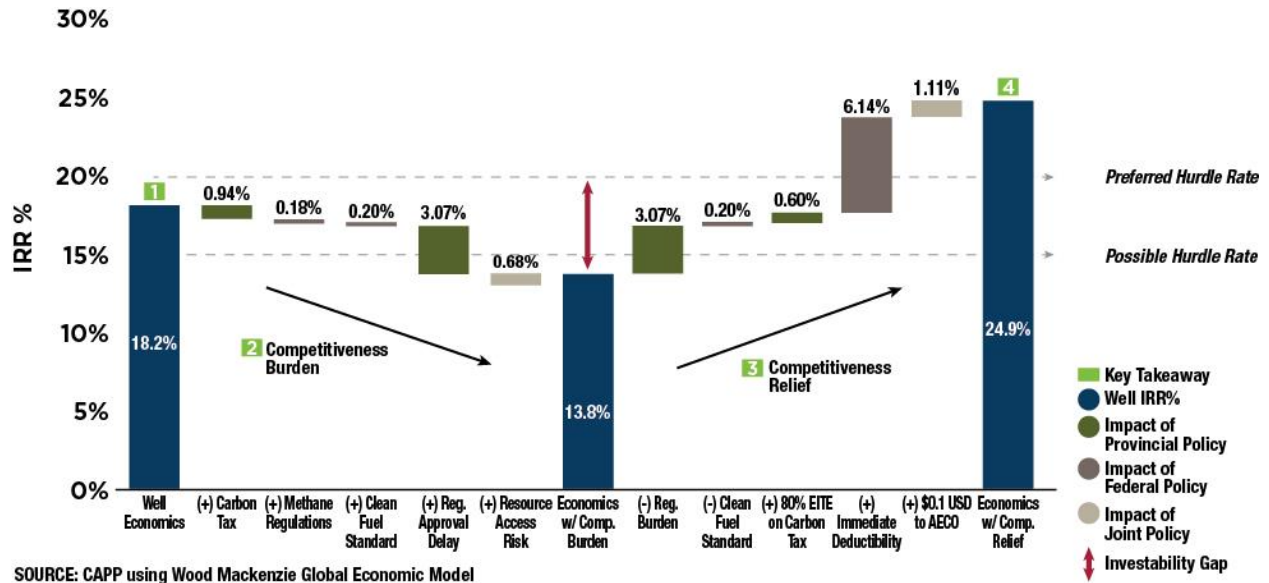


Figure 9: IRR Waterfall—Duvernay Kaybob Fox Creek (Wet Natural Gas)



Using Wood Mackenzie modelling data, vetted by CAPP members, CAPP modelled various policy levers that, when accumulated, would adversely impact well economics. These levers include land tenure issue, the provincial carbon tax, methane regulations, regulatory approval delays, and resource development risk. Federal levers include Species at Risk Act (SARA), federal immediate deductibility, and CFS.

The waterfall graphs follow an outline of the different application of the levers in sequence.

- 1. Alberta wells face varying levels of initial competitiveness challenges:** Depending on the well's costs and mix of products, its initial post-tax IRR varies. Of the wells profiled here, only one passes the 20 per cent hurdle rate. This is especially true for wells which have a heavier weighting towards natural gas production as Alberta producers continue to struggle to access markets due to pipeline constraints.
- 2. Current and pending climate and resource access policy contribute to the gap:** The implementation of a carbon tax, methane regulations, and the CFS are policies that, as conceived, could substantially erode competitiveness, particularly for drier natural gas wells. Regulatory delay and resource access risk are additional challenges weighing on the post-tax IRRs.
- 3. Fiscal policy, EITE treatment and regulatory reform can provide relief:** Addressing regulatory delay, removing the CFS and providing EITE protection on the carbon tax contributes substantially to improving well economics. However, without immediate deductibility of capital costs for corporate income tax, (as per the U.S. tax change) wells remain below their initial post-tax IRR, this immediate deductibility is within federal tax jurisdiction.
- 4. Immediate deductibility of capital costs and improved market access is still needed for more Alberta wells to be competitive:** Two of the three wells exceed the 20 per cent hurdle rate if they are able to deduct their capital costs immediately and if the AECO natural gas price differential to Henry Hub improves by US\$0.1. Alberta's Nova Natural Gas Transmission Limited (NGTL) pipeline system is currently severely bottlenecked. Addressing these bottlenecks will improve Alberta's ability to reach traditional U.S. markets and enable the supply of natural gas to support the transition from coal to natural gas-fired power generation, and as feedstock for value-added products within Alberta. The successful completion of LNG projects would also enable improved market access for western Canadian natural gas.

### **3.1.3 Competing with the U.S.**

Over the past decade, the U.S. has attracted substantial investment. Oil reserves in the U.S. have continued to grow at an astonishing rate, driven largely by new shale oil discoveries. Comparable U.S. shale investments have approximately two times the rate of return and a one-to two-year faster payout than their comparable Canadian plays. The U.S. has substantial inventory within the Permian with breakeven prices below \$45 WTI that compete directly with Canadian Shale plays like the Montney. However the Montney has far less inventory at similar \$45 breakeven price points.

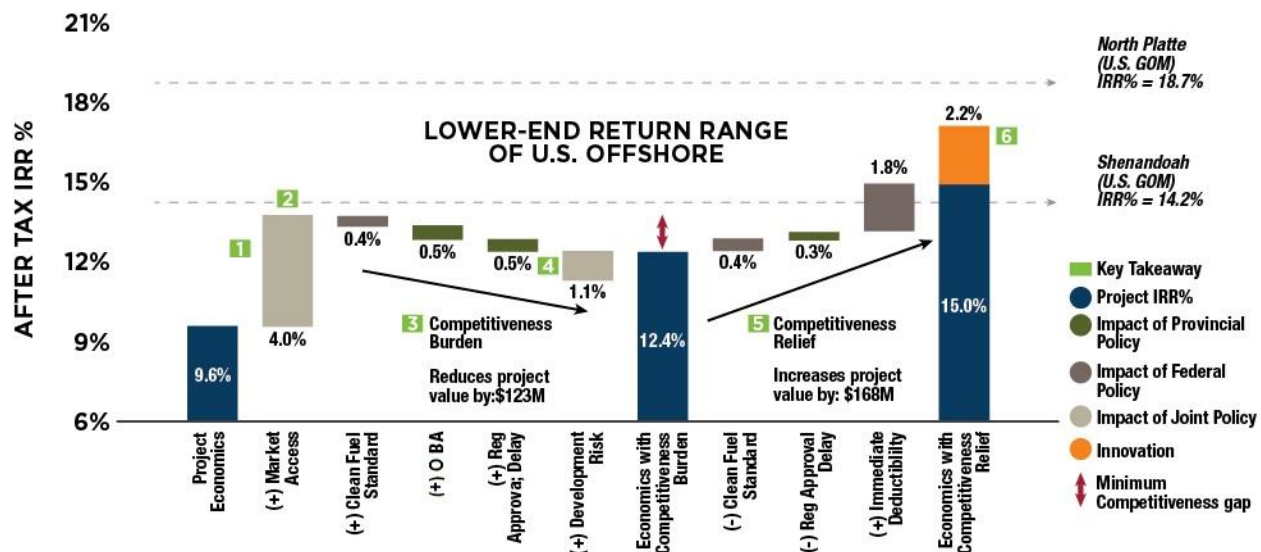
### **3.1.4 Oil Sands**

A generic 35,000-barrel-per-day (b/d) facility model created by Wood Mackenzie was used to quantify the broad impacts of policy issues on the economics of individual oil sands projects using an after tax IRR% as the key metric of project profitability.

Project economics were benchmarked against deep water projects (Shenandoah/North Platte) located in the U.S. Gulf of Mexico (GoM). These projects were selected on the basis that they are the least profitable Greenfield opportunities in the GoM expected to be developed within the next few years. Comparison of oil sands and deep water economics<sup>9</sup> is appropriate in that both types of projects share key similarities which influence the investment decision:

- Significant upfront capital investment (often in the billions of dollars) prior to any production of oil; and,
- Long-lasting, steady levels of production.

**Figure 10: IRR Waterfall—Generic 35,000 b/d in situ facility**



SOURCE: CAPP using Wood Mackenzie Global Economic Model

The following key findings can be drawn from the modelling results:

1. **Market Access is of central importance:** The Federal Court of Appeal ruling in August 2018 which overturned approval of the TMEP was a severe blow to investor confidence in Canada and the oil sands, in particular. A lack of market access significantly reduces the ability of oil sands producers to compete for capital by making the economics for new investment in the sector largely unworkable.
2. **Market access alone is not enough:** Market access cannot be considered a complete solution to the Canadian competitiveness gap. Assuming market access for the duration of the generic facility's productive life places its IRR%, just outside the lower-end return range of the least profitable deep water opportunities. At this level, new investment will remain challenged.

<sup>9</sup> Such a comparison also has a precedent in the recent Alberta Royalty Review. GoA, Alberta's Modernized Royalty Framework, 2017.

3. **Implementation of current/pending policies contributes to the gap:** Additional climate costs<sup>10</sup>, as well as regulatory delays, widen the competitiveness gap to the GoM by reducing project return by 1.4 per cent.
4. **Additional downside risk:** Further downside risk to project economics is created by initiatives such as the caribou habitat recovery under the SARA and land tenure issues. Resource access risk is included outside of the waterfall because while it has the potential to pose a significant challenge to future investment, the effect of this issue is potentially decades in the future and difficult to predict.
5. **Fiscal policy reforms can provide relief:** The policy levers available to governments at both the provincial and federal levels have the potential to greatly enhance Canada's competitive position relative to comparable opportunities in the U.S. GOM.
6. **Funding innovation will be difficult if oil sands are not competitive:** Technology has the potential to substantially improve the economics and the environmental performance of the oil sands industry, most notably through emerging steam reduction/value-add technologies. However, oil sands is a learning-by-doing industry and it takes time and significant investment to successfully implement new technologies on a commercial scale. Producers need to attract capital to drive innovation which will not occur if the competitiveness gap is not corrected. The introduction of immediate deductibility of capital costs is the most significant lever for encouraging oil sands innovation. At a provincial level, recognizing research and development (R&D) expenses as eligible for royalty credits and removing inequities in the royalty system would encourage producers to invest in R&D.<sup>11</sup>

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<sup>10</sup> CFS and the shift to a carbon tax based on Output Based Allocation (OBA)

<sup>11</sup> This lever was not included in the above waterfall owing to the fact that it is difficult to quantify the proportion of research and development (R&D) spending currently deductible for royalty purposes.



## 4 Oil and Natural Gas Competitiveness as an Alberta Priority

While some of the challenges confronting the sector are driven by the federal government, others fall squarely in the purview of the provinces. If Canada's oil and natural gas industry is to be competitive in the future, it is going to take a concerted effort from the provinces and the federal government. As part of its 2018 economic report series, CAPP's report, *Canada's Role in the World's Future Energy Mix*,<sup>12</sup> recommended the GoC take a leadership role in defining Canada's vision for oil and natural gas that positions the upstream industry as the global supplier of choice to meet the world's growing energy needs. This vision should be supported through a co-ordinated effort with industry, provincial and territorial governments, and individual Canadians to create an effective policy and regulatory environment that encourages investment in Canada's resources, ensuring those resources are produced with environmental and social responsibility.

The GoA should adopt a vision for future development of the industry, complete with specific goals and performance metrics relating to the health of the industry, including investment, production, and project-approval related targets (e.g., pipelines, investment and share of global supply).

By way of example, through its *Advance 2030* initiative, the Government of Newfoundland and Labrador envisioned the following goals for its upstream oil and natural gas sector:<sup>13</sup>

- More than 100 new exploration wells drilled;
- Multiple basins producing more than 650,000 barrels of oil equivalent per day (boe/d);
- Shortened time from prospectivity to production;
- Direct employment of more than 7,500 people in operations;
- A robust, innovative global supply and service sector;
- Commercial natural gas production; and,
- Renewables and oil and natural gas integrated in a world-class energy cluster.

Alberta's vision needs to be combined with a strong commitment to implementation, which will take a concerted effort from all relevant areas of government. In 2017 CAPP recommended the province adopt a "whole of government" approach and mandate to strengthen Alberta's investment attractiveness while achieving government policy objectives. We remain supportive of this proposed vision.

The sector is directly affected by a number of ministries, including Alberta Energy (AE), AEP, IR, and the AER. Other ministries beyond those that directly set policy and regulate oil and natural gas development, such as Finance, Municipal Affairs and Economic Development and Trade, also have a significant potential impact on competitiveness.

In order to ensure a vision of competitive oil and natural gas development is adopted as a government-wide priority and focus, CAPP recommends the province require all ministries

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<sup>12</sup> CAPP, *Canada's Role in the World's Future Energy Mix*, 2018.

[https://context.capp.ca/articles/2018/feature\\_capp-economic-report-2](https://context.capp.ca/articles/2018/feature_capp-economic-report-2)

<sup>13</sup> Newfoundland and Labrador, *Advance 2030*, 2018.

<http://www.releases.gov.nl.ca/releases/2018/exec/0219n01.aspx>



meeting with the oil and natural gas sector adopt improving competitiveness as a key consideration in their decision-making processes, and work with industry accordingly. This government-wide approach is necessary to advance policy solutions in the following sections.

## 5 Market Access

Achieving market access has the potential to add substantial value to the sector. Currently, Canadian oil and natural gas sales are mainly restricted to markets in Canada and the U.S. A lack of market access has resulted in a significant discount in the price for Canada's resource.

Canada's limited oil pipeline takeaway capacity results in heavy discounts on Canadian oil and challenges investment in new and existing projects. Current pipeline constraints will cost oil producers \$10.8 billion to \$15.6 billion in annual revenue<sup>14</sup> depending on whether rail capacity can fill the transportation gap.<sup>15</sup>

Canada's energy industry has an opportunity to supply the world with sustainably produced oil and natural gas. For industry to look beyond North America's borders, it is critical to find a way to get oil and natural gas resources to the coast for global export.

The premier and the GoA have championed the need to expand market access by advocating for the TMEP. CAPP supports the province in their tireless advocacy on this front. However, the recent Federal Court of Appeal's decision on TMEP is further evidence Canada's regulatory system has created uncertainty for industry and investors. It also highlights the need for continued efforts by the GoA to champion expanded market access for the oil and natural gas industry.

In this regard, CAPP encourages the Alberta government to continue to support TMEP, but also to strengthen its support for LNG development on Canada's West Coast with a comparable level of commitment. LNG has the potential to substantially benefit Alberta natural gas producers, which in turn benefits all Albertans and generates revenues for the province.

In addition, CAPP encourages the province to actively support industry's position in relation to pause and review the federal Bill C-69 and eliminate Bill C-48. There is an opportunity for the Alberta government and industry to send a strong and firm message to the federal government and stand up for Alberta.

### Recommendations

- Continue to advance efforts to expand market access for Canadian heavy oil through the support and endorsement of approved pipelines and expansion projects (including TMEP, Keystone XL and Enbridge Line 3).
- Visibly support and take action to advance the development of an LNG industry on Canada's West Coast with development of multiple LNG plants over time to provide access to global natural gas markets. The market window will otherwise continue to be seized by LNG projects in other jurisdictions.

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<sup>14</sup> Perrault, Jean Francois, Johnston, Rory, Pipeline Approval Delays: the Costs of Inaction. Global Economics. Scotiabank. February, 2018.

<sup>15</sup> Ibid.

- Support the reduction of the NEB approval process to 12 months for repeatable applications (expansions in existing right of ways). North American natural gas markets are highly competitive and market opportunities must be captured expediently to be successful. CAPP also recommends that the GoA facilitate a process to investigate a pre-permitting process for existing rights of way.
- Implement measures to reduce transportation costs on Canadian pipelines that serve markets also supplied by U.S. natural gas such as debottlenecking, etc.
- Undertake a review of the current challenges associated with operating mature natural gas assets in Alberta and find near-term opportunities to provide cost relief (i.e., reform asset valuations for the purposes of assessing property tax).
- Support industry in its efforts to lobby the GoC to pause and review Bill C-69 to strengthen investor confidence and encourage long-term investment in energy infrastructure.
- Support industry in advocating against a moratorium on tanker traffic off Canada's West Coast. Bill C-48 is not supported by science and is a self-imposed barrier to trade that ultimately harms Canada.

## 6 Regulatory Competitiveness

Regulatory competitiveness is one of the most significant opportunities available to the province to strengthen industry competitiveness. An optimal regulatory system will be efficient and effective at achieving outcomes, and appropriately and effectively engage stakeholders in the process.

The AER has been working with industry to find areas of opportunity to improve regulatory efficiency and outcomes. Industry is committed to continue working with the AER to improve regulatory efficiency. Review of these operational and regulatory items through a competitiveness lens on an ongoing basis is required to improve and maintain the competitiveness of the regulated community and provide benefits to government, the regulator, and Albertans.

### 6.1 Regulatory Efficiency and Effectiveness

The oil and natural gas industry supports a regulatory environment that provides Albertans with the confidence resources are being responsibly developed, while providing a streamlined regulatory environment facilitating investor confidence.

The province's current regulatory environment has contributed to the erosion of investor confidence in the oil and natural gas industry. Alberta's regulatory framework is fraught with process inefficiencies, lengthy approval timelines, and escalating regulatory costs that, combined, increase costs and generate investor uncertainty in Alberta's regulatory system.

Regulatory efficiency and effectiveness for Alberta can be enabled through a focus on three key components:

- **Reducing Timelines** – Initiatives that will decrease current regulatory timelines and/or increase regulatory certainty while achieving outcomes.
- **Modernizing Regulation** – Initiatives that address legacy/heritage regulatory requirements and/or recognize evolution in the industry and remove associated constraints.
- **Improving Efficiency** – Initiatives that reduce regulatory costs and/or burden where those aspects add limited to no value, to protection of the environment, public safety or the Alberta economy.

#### 6.1.1 Alberta Application Timelines

Timelines are a key component of regulatory competitiveness. Certainty for application timelines, including timely approvals and consistency in achieving those timelines, is key to maintaining investor confidence and a competitive regulatory system.

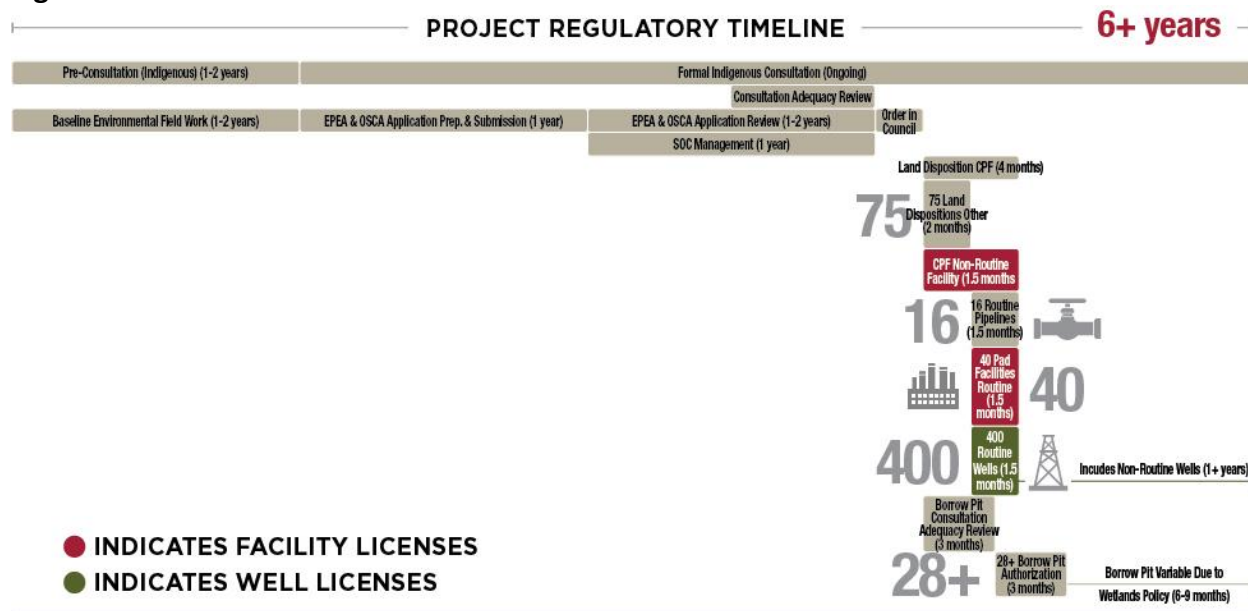
Alberta's regulatory application process is extraordinarily complex. By way of illustration, a typical in situ development in Alberta has a best-case approval timeline from the start of consultation through to the start of construction of four to six years,<sup>16</sup> and could require more

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<sup>16</sup> Review of regulatory applications submitted by proponents in Alberta.

than 560 separate, and potentially sequential, regulatory approvals, authorizations or permits under more than 15 distinct regulations or acts (Figure 11).<sup>17</sup>

**Figure 11: Timeline Chart In situ Oil Sands**



Regulatory requirements generally drive the critical path for oil and natural gas developments and can significantly affect competitiveness and investor confidence. As illustrated in the example above, an oil and natural gas development is likely to require multiple well and/or facility approvals as well as additional permits, approvals, authorizations and consents under other regulations and policy, all of which may need to be submitted sequentially. Multiple approvals and permits with long or uncertain timelines add to the regulatory risk and uncertainty. In addition to the necessary permits and approvals, other considerations related to lease tenure. Indigenous consultation, resource access, among others, increase the overall timelines and associated uncertainty with oil and natural gas projects in Alberta.

Regulatory inefficiencies and delays in one aspect of the process could potentially affect an entire project. For example, a delay with a borrow pit could delay the ability to construct and drill a well pad, ultimately delaying the development of an entire in situ project.

This complexity creates challenges for industry, government and regulators in evaluating the efficiency and effectiveness of the regulatory system and improving performance. In its 2017 report, CAPP surveyed its members and estimated that aggregate timelines for a non-routine well application in Alberta could take as long as 144 days. This analysis included aspects of Indigenous consultation, surface tenure acquisition, and well licensing.<sup>18</sup> The 2017 table (Table 1) is included for reference.

<sup>17</sup> Blake, Cassels & Graydon LLP, Overview of Environmental Regulatory Regime Related to Alberta Oil Sands Activities, 2010.  
[http://www.blakesfiles.com/Guides/2010\\_Blakes\\_Environmental\\_Regulations\\_Alberta\\_Oil\\_Sands\\_EN.pdf](http://www.blakesfiles.com/Guides/2010_Blakes_Environmental_Regulations_Alberta_Oil_Sands_EN.pdf).

<sup>18</sup> CAPP, A Competitive Policy and Regulatory Framework for Alberta's Upstream Oil and Natural Gas Industry, 2017, p. 29-30.

**Table 1: Target Approval Timelines**

Alberta	B.C.	Saskatchewan	U.S. Federal	U.S. Freehold - Texas	U.S. Freehold - Other
<b>Non-Routine with SOC*:</b> 198-220+ days	90-128 days (up to 130-day advantage)	72-120 days (up to 148-day advantage)	120 days (up to 100-day advantage)	<30-60 days (up to 190-day advantage)	90 days (up to 130-day advantage)
<b>Non-Routine:</b> 116-144 days					
<b>Routine:</b> 79-119 days					

\*Note: that while these timelines provide estimates based on recent operator data with respect to applications involving SOC's, in some cases SOC's may result in even more protracted timelines.

In order to enable a more robust analysis of regulatory performance based on tangible, third-party information, CAPP procured publicly available data from the AER to conduct a review of application timelines for a range of activities including single well licences, facility licences, licence transfers, and commercial schemes for new in situ facilities.<sup>19</sup>

The following analysis is illustrative in that it only looks at specific aspects of licensing under the current AER Directives – an approximately 1.5-month period of an overall four- to six-year approval timeline for an in situ facility. A more complete analysis would include an assessment of regulatory performance data for all aspects of the approval process. However, this information is not publicly available, particularly from the AEP and IR.

### **Well and Facility Licence Application Timelines**

Most oil and natural gas activities in Alberta share a requirement for wells in order to facilitate resource extraction and for facilities in order to generate production.

Table 2 depicts the number of well and facility applications submitted between 2014 and 2017. Interestingly, the proportion of applications classified as routine has decreased over time. In contrast, the number of applications classified as non-routine PI has nearly doubled. It is these non-routine PI applications that tend to require significant additional time for approval and that exhibit the greatest variability in approval timelines (Figures 12 and 13).

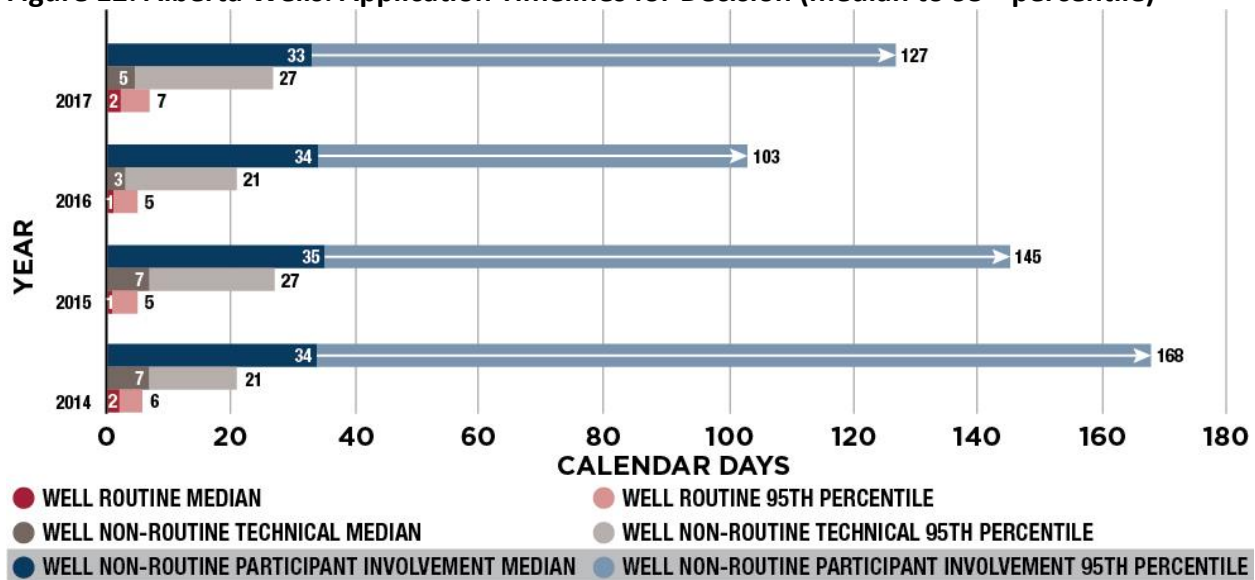
**“The proportion of applications classified as routine has decreased over time. In contrast, the number of applications classified as non-routine PI has nearly doubled.”**

<sup>19</sup> AER, [www.aer.ca](http://www.aer.ca). Application and licensing data accessed through TOPANALYSIS TOP Regulatory, [www.topanalysis.com](http://www.topanalysis.com) on July 16, 2018.

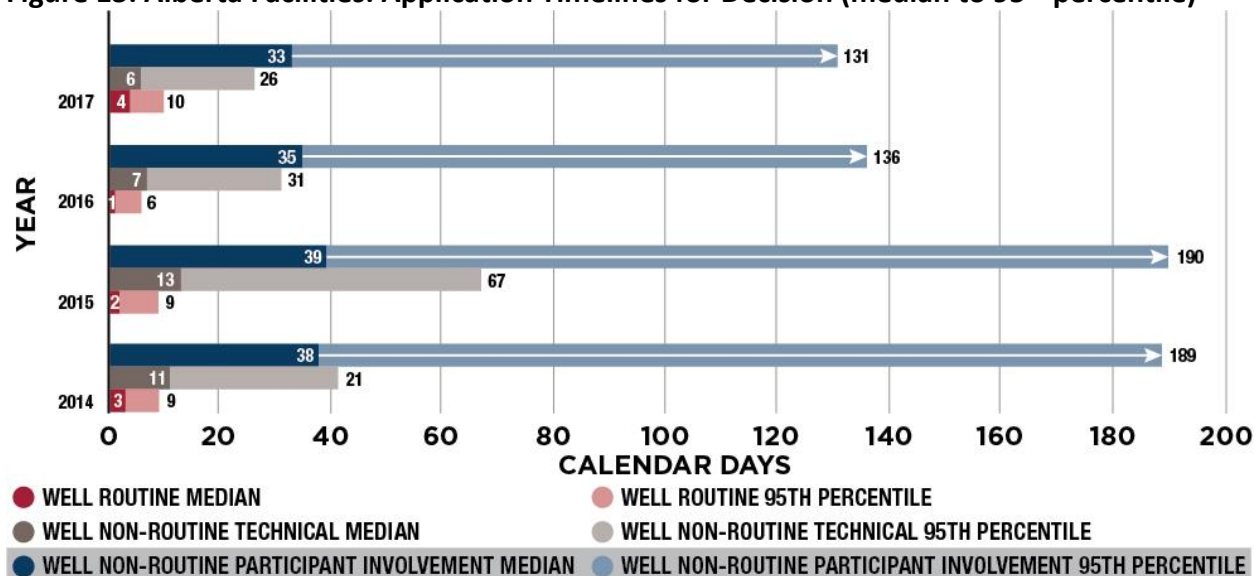
**Table 2: Well and Facility Applications Submitted in Alberta (as a percentage of total; closed and pending)**

Application Year	FACILITIES			Total	WELLS			Total
	Routine	Non-Routine Technical	Non-Routine PI		Routine	Non-Routine Technical	Non-Routine PI	
2014	57%	35%	8%	2980	94%	3%	4%	10,498
2015	55%	36%	9%	1721	92%	2%	6%	5833
2016	61%	26%	13%	1231	93%	2%	5%	5153
2017	54%	31%	15%	1697	90%	2%	8%	6298

**Figure 12: Alberta Wells: Application Timelines for Decision (median to 95<sup>th</sup> percentile)**



**Figure 13: Alberta Facilities: Application Timelines for Decision (median to 95<sup>th</sup> percentile)**



According to the AER data as presented in Figures 13 and 14, median application timelines for routine licences have remained relatively consistent since 2014. Routine well applications were approved in approximately two median days in 2017 (95<sup>th</sup> percentile of seven days), and routine facility applications were approved in approximately four median days (with a 95<sup>th</sup> percentile of 10 days).

While there is some variation in the approval timelines for routine well and facility applications, the non-routine PI applications demonstrate substantial variation.<sup>20</sup>

For non-routine PI well and facility applications, application timelines are significantly variable between the median and the 95<sup>th</sup> percentile of the application timelines. In 2017, non-routine PI well application timelines varied from 33 median days to 127 days at the 95<sup>th</sup> percentile. Non-routine PI facility application timelines varied from 33 median days to 131 days at the 95<sup>th</sup> percentile. It is this variation, in combination with the extensive associated timelines, which creates the uncertainty that undermines investor confidence in Alberta's regulatory system. If Alberta wants to compete, it needs to address both the duration and the variation in application timelines for all aspects of the regulatory process.

### **Licence Transfer Timelines**

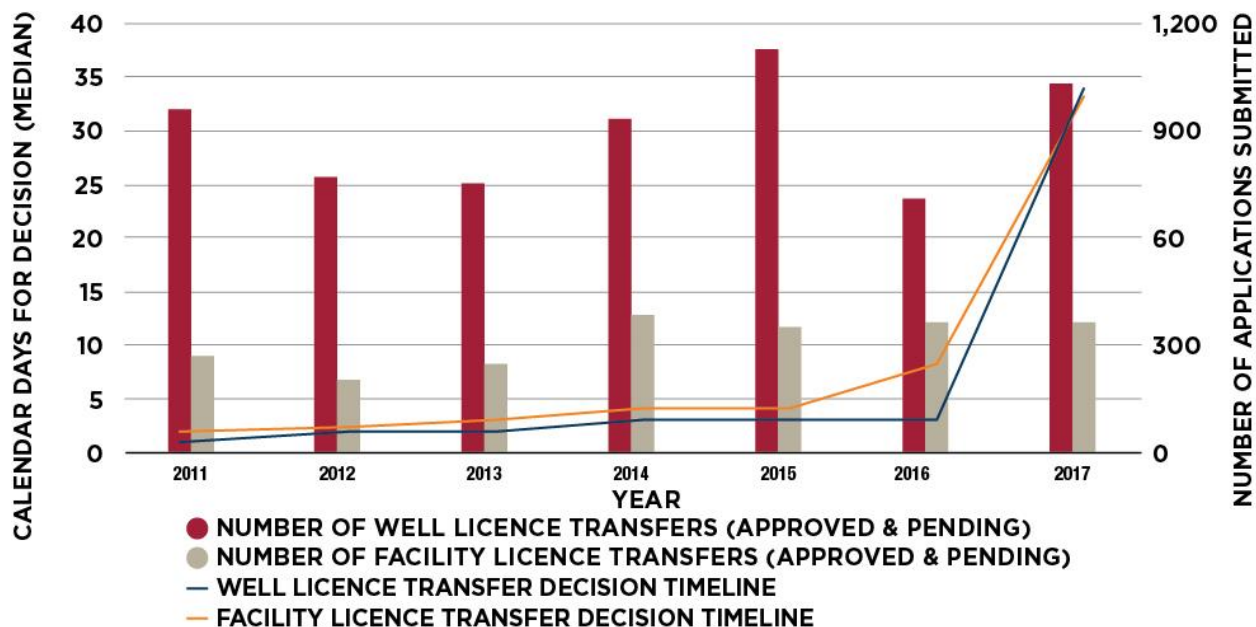
Licence transfer applications (well and facility) have seen a significant increase in median processing times, with timelines increasing by more than 30 per cent from 2015 (Figure 14). This is primarily attributable to implementation of a public notice of application (PNOA) period for licence transfer applications. Regulatory changes such as this result in longer approval timelines (approximately 30 days for each well and facility licence transfer), which increases uncertainty and decreases competitiveness. The AER is currently seeking to accelerate the approval timeline of licence transfer applications. However, the significant increase in timelines as a result of the PNOA requirement for all transfer applications remains concerning.

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<sup>20</sup> The trend for non-routine technical application timelines is decreasing. However, in many cases applications are being submitted as non-routine technical due to outdated or obsolete technical requirements, not because of the potential risks associated with the technology proposed.



**Figure 14: Facility and Well Licence Transfer Application Timelines**



### Oil Sands Application Timelines

The number of applications for new in situ oil sands facilities has decreased since the commodity price downturn. Since 2015, only five applications were made for new in situ oil sands facilities. By contrast, between 2010 and 2014, there were 44 applications made for new in situ oil sands facilities.<sup>21</sup>

Table 3 lists the oil sands scheme approvals currently pending approval in Alberta. Since 2011, 36 per cent of the in situ oil sands applications submitted are waiting for a decision. Some in situ applications have been waiting for a decision for as long as 80 months.<sup>22</sup>

<sup>21</sup> Decisions for applications made since 2016 are still pending, therefore median timelines for decisions are not yet available for analysis.

<sup>22</sup> These applications are delayed at various points in the regulatory approval process, including some delays that are at the request of the proponent due to financial capacity and market factors, and delays with the stakeholder engagement process.

**Table 3: Oil Sands Scheme Approvals Pending Approval**

Project	Year Submitted	Review Period (Months to Date)
1	2017	9.6+
2	2017	17.5+
3	2016	19.8+
4	2014	44.6+
5	2013	55.6+
6	2013	55.8+
7	2013	57.0+
8	2013	65.2+
9	2012	70.3+
10	2012	70.7+
11	2012	77.1+
12	2011	79.7+
13	2011	80.2+

These applications are only one component of a significant approval process for oil sands projects, preceded by exploration approvals and permits, and submitted in conjunction with applications for approval under the *Environmental Protection and Enhancement Act* (EPEA) and the *Water Act*, followed by applications under the *Public Lands Act*, the *Oil Sands Conservation Act* (OSCA) and other applications including well and facility licences as discussed above.

The following key findings can be drawn from the timelines analysis:

1. **Variability in decision timelines affect certainty:** As demonstrated for wells and facilities, approval timelines vary significantly, resulting in project uncertainty that adversely affects investor confidence in oil and natural gas development in Alberta.
2. **Broader regulatory process increases uncertainty:** Well licences, facility licences and license transfers are a relatively minor component of the overall regulatory process in Alberta. The broader regulatory process needs to be addressed to reduce redundancy, and streamline all aspects. The full regulatory cycle needs to be addressed from lease tenure and resource access through to land dispositions and well licences, and must include improvement to the PI processes.
3. **Non-routine application criteria requires modernization:** Applications submitted non-routine due to PI or technical considerations greatly affect regulatory certainty. Modernization of technical requirements to align with best practices and new technology in conjunction with enhancement of PI processes are required.

### 6.1.2 Reducing Approval Timelines and Variation

This discussion and analysis demonstrates that Alberta faces extended timelines and significant variability in applying and receiving approvals for oil and natural gas activities. For well and facility licence applications specifically, non-routine PI applications are a substantial concern.

These delays are significant. By way of example, a steam-assisted gravity drainage (SAGD) project includes one or more central processing facilities, which have associated possible capital investment ranging from \$750 million to \$1.35 billion. An oil sands mine facility ranges from \$9 billion to \$11 billion for a stand-alone facility (no upgrader). These facility costs are for the facility only and do not include associated infrastructure.<sup>23</sup> As discussed in the modelling section, regulatory delays can reduce oil and natural gas IRRs by as much as five percentage points.

**“If Alberta wants to compete, it needs to address both the duration and the variation in application timelines for all aspects of the regulatory process.”**

The primary focus for the AER and Alberta ministries should be to work with the regulated community to substantially streamline the regulatory approval process – eliminating redundancies and improving consistency to reduce timeline length and variability in project approvals, while continuing to achieve social and environmental outcomes.

### **Timeline Review/Optimization**

There is an opportunity to explore additional initiatives focusing on efficiency and an overall reduction of timelines for applications across the sector. One of the most significant opportunities to reduce approval timelines and variability is through setting binding targets and benchmarks that are comparable to other jurisdictions. CAPP has conducted a comparative assessment of the approach and performance of other jurisdictions (e.g., Saskatchewan, British Columbia, Texas and Oklahoma), some of which have integrated their application processes and set binding timelines for when applications will be approved (see appendix).

## **Recommendations**

The province should review its own internal data as well as comparable data in competing jurisdictions and establish specified timeline benchmarks and performance metrics to target reductions in approval times and variability for regulatory applications.

For conventional/unconventional oil and natural gas development:

- Set benchmarks that are jurisdictionally competitive (i.e., for comparable application streams, at or below B.C. and Saskatchewan approval timeline benchmarks).
- Decrease non-routine technical application timelines for wells and facilities by examining and de-risking non-routine technical considerations that are lower risk or have become standard practice through technical evolution of the industry.

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<sup>23</sup> AER Crude Bitumen Supply Cost Reference. March 2018.

For oil sands:

- Accelerate development within approved oil sands project areas, including considering prior engagement in decisions on SOCs, expediting decision making and using authorizations in place of approvals where activity is consistent with original approval.
- Examine current timelines for OSCA schemes and EPEA approvals and develop a transparent accounting of the time required to process such applications.
- Leverage learnings from the current timelines to develop an optimized benchmark for each category of application and amendment under OSCA and EPEA that is proportionate to actual time required for review and addresses the oil sands development planning horizons.
- Implement measures as applied to conventional/unconventional development, as applicable, for all additional applications and approvals required for oil sands development outside of the OSCA scheme and EPEA approvals (e.g., D 056, land disposition, etc.)

### Integrated Decision Approach

The province has taken steps to streamline the approval processes through initiatives like the IDA and SOC process improvements.

The AER's IDA has significant potential to move the needle on approval timelines in Alberta. The two main components of IDA are:

- **One application, one review, one decision:** A simultaneous approval process that establishes one process for consultation, environmental assessment, stakeholder engagement and approval under multiple enactments (e.g., including all or part of *Public Lands Act*, *Water Act*, *OSCA* or *Oil and Gas Conservation Act*, and the *EPEA*). On a small scale, this would include bundling the land disposition, drilling permits, well licences, water licences, facility licences and operating approval for a single well pad. At the other end of the spectrum, this may encompass all aspects of an in situ oil sands development as was seen in the recently completed pilot for Suncor Energy's Meadow Creek East project.
- **OneStop implementation:** A technology solution, with accompanying risk rules, that allows proponents, stakeholders and the regulator to submit, view and review applications expeditiously and transparently. Implemented to date for reclamation certificates, pipeline applications and amendments, *Water Act* applications and amendments, and certain notifications; industry has seen a distinct improvement in routine application processing timelines in these areas.

In August 2018, it was announced that the AER had completed implementation of some phases of the IDA. While it remains to be seen whether the IDA can deliver results similar to those achieved during piloting (for SAGD translating to a three-per-cent reduction to capital expenditure, reduction of approval timelines from five years to 15 months), successful implementation will potentially have a positive impact on the economics of Greenfield oil sands investment.<sup>24</sup>

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<sup>24</sup> Refer to Section 3.1.1 for quantification of this impact.

Industry understands there is an intent to actively progress the IDA approval process for in situ project applications based on the success of the in situ pilot. However, in considering the potential associated with IDA, a number of concerns have been identified that need to be addressed in order to ensure the success of IDA for major in situ project applications including:

- Requirements for up front payments for all planned disturbance for the life of the project as well as for wetlands assessments and compensation (as sited, not as built);
- Differences in legal expiry dates;
- Flexibility for footprint placement to optimize resource recovery and reduce potential impacts as further described in the Section 6.1.4 of this report relative to PADs; and,
- Definition around the PI requirements for IDA to ensure shared expectations, also as described further in this report.

By comparison, both Saskatchewan and B.C. have successfully implemented consolidated approaches to application approvals. This shift to bundled applications in B.C. has consolidated applications for activities which may include wells, roads, pipelines, facilities, geophysical, *Water Sustainability Act* authorizations, and other upstream industry-related activities. Once an approval is issued in B.C., various reviews for the project are complete and the project can proceed. Conversely in Alberta in the absence of implementation of IDA for applications, a well or facility approval must also be accompanied by one or more of a *Public Lands Act* disposition, a *Water Act* approval, and/or other approvals under the *Oil and Gas Conservation Act*, or EPEA, each of which has an associated timeline for review, approval and consultation. The B.C. application timelines also include Indigenous consultation, whereby B.C. has agreed-upon timelines as stated in Consultation Agreements with First Nations. For example, in the draft interim consultation procedure,<sup>25</sup> timelines could range from 15 to 30 days, depending on the complexity of the application. The median timeline for project approvals in B.C. from 2016 through 2018 was 44 days (see the Appendix for further details).

## Recommendations

- Continue and expedite the implementation for both aspects of IDA highlighted above. In progressing the IDA approach, CAPP recommends that the AER consider the practices employed for bundling of applications in B.C.
- To enable IDA to achieve its potential, focus on modernizing participant requirements for Alberta oil and natural gas development, which should be advanced in conjunction with other PI initiatives such as SOC process improvements and harmonization of the AER and ACO processes.
- Align across government departments to recognize the potential regulatory competitiveness benefits of the IDA approach for consolidated applications and actively and collaboratively resolve barriers to enable full implementation of the approach, including timing of payments, legal expiry dates and PADs.

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<sup>25</sup> B.C. Oil and Gas Commission (OGC), Interim Consultation Procedure. Available at <https://www.bcogc.ca/node/13044/download>

### **Statement of Concern Process Improvements**

The SOC management process is a good example of an opportunity to improve approval timelines and increase regulatory certainty. As discussed, the greatest amount of uncertainty, longest approval timelines, and highest level of variability is attributable to applications that are non-routine due to PI. A contributing factor to these concerns is the processes by which SOC are managed by the AER.

There is an opportunity to advance a number of SOC management-related process concerns in order to streamline and expedite the SOC process, and by extension the approval process, without adversely impacting PI. Industry has recommended to the AER a number of potential initiatives aimed at improving the transparency, consistency and effectiveness of the SOC process and continues to work to advance those initiatives with the AER.

### **Recommendations**

- Introduce improvements to advance towards a more effective, transparent and meaningful SOC process for stakeholders, industry and regulators. Opportunities to improve the SOC process include:
  - Leveraging Section 5.2 of the AER Rules of Practice<sup>26</sup> to enable the AER to recognize prior PI and the potential for adverse environmental effects, and reduce the number of applications for which a public notice period must be allowed prior to decision; and,
  - Applying Section 6.2 of the Rules of Practice<sup>27</sup> more broadly to enable the AER to expedite decisions with regards to SOC filed, thus improving timelines associated with the SOC process. Section 6.2 can be used to address concerns with SOC applicability, known objectors, consideration of past decisions, among others.

### **Streamlining the Regulatory Process for Activity within Approved Oil Sands Project Areas**

While there will be some opportunity for new Greenfield projects in the near term, much of the renewed investment and growth in oil sands is more likely to occur via step-out projects associated with existing and approved developments. To facilitate such growth, streamlining the regulatory process for activity within previously approved project boundaries presents a low-risk opportunity to significantly reduce regulatory burden, timelines, uncertainty and associated cost without compromising environmental outcomes.

All existing approved oil sands projects underwent a highly rigorous and comprehensive process to demonstrate the proposed development could meet Alberta's environmental standards. Upon construction, those same projects are then subject to a monitoring, compliance and enforcement system that transparently demonstrates operations are actually meeting those environmental standards. This world-leading regulatory system and the environmental

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<sup>26</sup> Province of Alberta, AER Rules of Practice, 2013. [http://www.qp.alberta.ca/documents/Regs/2013\\_099.pdf](http://www.qp.alberta.ca/documents/Regs/2013_099.pdf)

<sup>27</sup> Ibid.

standards it upholds provides strong justification for the regulatory streamlining of development activity within approved projects.

Oil sands project approvals should be meaningful for all stakeholders. Issues addressed through the original project approval process should not have to be revisited when the proponent undertakes activity consistent with that approval. Three specific areas of opportunity for streamlining include:

- Expediting decisions on all SOC's for activities within the project area that are consistent with the regulatory approval and the impacts originally assessed. There should also be an opportunity to reduce the number of activities requiring public notice.
- Maximizing the practice of providing authorizations as opposed to requiring amendment applications as provided for under EPEA (e.g., installation of equipment, conducting pilots, submissions required as a condition of approval, revisions to reporting and submission deadlines, etc.)
- Leveraging the expedited decision-making authority provided for in the Rules of Practice<sup>28</sup> where an application is deemed necessary (e.g., where it is determined that there is minimal or no adverse effect on the environment or adequate notice has already been given).

## **Recommendation**

- Streamline the regulatory process for activity related to previously approved oil sands projects by relying on the rigor of the original project approvals.

### **6.1.3 Improving Efficiency through Stronger Inter-Departmental Integration**

The Canadian regulatory system includes numerous federal, provincial, territorial, regional and municipal laws and regulations. Within Alberta, the AER is positioned as the single regulator for oil and natural gas activity. However, policy and regulation in the province creates interdependencies between the AER, government ministries and the ACO, as well as other agencies. These regulatory initiatives and inter-dependencies have often been built on top of each other without consideration of how they fit into a comprehensive framework. This results in a complex, inefficient and often redundant system, which leads to delays and uncertainty. Specific regulatory efficiency initiatives and recommended approaches are discussed below.

#### **Alberta Energy Regulator and Aboriginal Consultation Office**

The ACO and AER processes are not harmonized and too frequently lead to inconsistent guidance to proponents and Indigenous communities. The GoA and AER have indicated that they are undertaking a collaborative review of the joint operating procedures. As of yet the outcomes of this review are unclear and opportunities for industry engagement have yet to be defined.

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<sup>28</sup> Ibid.



The GoA has indicated that centralizing the AER's directly and adversely affected test with the ACO's test of adverse impact to exercise treaty rights and traditional uses will not be pursued. All aspects of the consultation process for Indigenous communities will remain with the ACO. There are a number of initiatives underway that are increasing burden on industry and communities, and have increased timelines for decisions with Indigenous concerns. The consideration is further exacerbated when federal review for a project is also required, at which time additional, duplicative consultation occurs for the same project.

## Recommendations

- The creation of concurrent and harmonized AER, SOC and ACO processes, including advancement of a collaborative and focused effort to improve and align the SOC management process with the ACO's processes. It is recommended that this be advanced as a project through the AER in conjunction with the ACO and incorporated into any revisions to the First Nation and Métis Settlements consultation policies.

## Borrow Pit Requirements

Multiple regulatory bodies with overlapping jurisdiction create a number of issues that delay construction schedules and also lead to negative environmental and social outcomes. An example of this overlap is found with respect to borrow pit approvals required for oil and natural gas development, which are under the jurisdiction of AEP, but have to be included in planning and applications submitted under the AER, which leads to delays and uncertainty.

In 2017, the AER and AEP launched a Borrow Pit Task Team to implement a two-phase approach to resolve the issue including release of a borrow pit directive by AEP to clarify the current requirements for obtaining borrow dispositions (Phase One) and legislative and/or regulatory changes initiated by AEP to enable the AER to assume oversight for borrow pit dispositions in conjunction with activities under AER jurisdiction (Phase Two).

Delivery of Phase One, the Borrow Pit Directive, by the AEP continues to be delayed and, consequently, initiation of the second phase of the project has yet to occur. Current processes create inconsistencies between project reclamation plans and disturbance, extend timelines for project development, and have the potential to drive increased footprint and fragmentation due to inefficiencies.

## Recommendations

- Expeditionary advancement of Phase Two of the project to address the borrow pit efficiency issues. This must include a concerted effort by AEP and AER to advance the legislative and regulatory amendments as soon as possible to consolidate responsibility for borrow pits for energy projects under the AER.
- Identification and examination of other areas of jurisdictional overlap and resolution of those overlaps to ensure a transparent, consistent and comprehensive approach to regulation of activities related to oil and natural gas development.



### **Survey Plan Requirements**

In September 2014, the AER introduced a new process for the renewal of existing land dispositions resulting in significant increases to timing and costs. In early 2018 the AER identified two projects that are intended to address the more than 2,000 land dispositions that have expired or will expire between 2017 and 2021, as well as issues flagged by industry relative to delayed reclamation certificate applications due to current requirements. While the AER had previously completed a short-term fix that addressed these issues in the near term, a long-term fix is challenged by policy constraints.

### **Recommendations**

- Developing a practical solution to ensure that surface land dispositions are adequately captured in provincial digital data systems, which also accommodates adjustment of record to reflect actual footprint on the landscape where discrepancy has arisen as a result of identified historical considerations and non-intentional non-compliance.
- The AER has validated that the use of alternative technologies is effective in identifying disposition footprints on the landscape in Alberta. As such, CAPP recommends recognition of these alternative means for review/validation of footprint with respect to survey plans.

#### **6.1.4 Modernizing Regulation**

Industry faces multiple regulatory challenges that create unnecessary costs, cause delays, result in significant inefficiencies, and are potentially redundant. Some of these regulatory challenges are new, while others have been in place for a considerable amount of time and may not have evolved with advances in technology and innovation. Many of the issues encountered most recently with projects in this area (e.g., PAD, Master Schedule of Standards and Conditions [MSSC], borrow pits, etc.) arise due to the complexity introduced via regulatory inter-jurisdictional roles and responsibilities.

### **Addressing Legacy Requirements Applied to New Technologies**

The AER and AEP continue to advance a number of technical projects to address legacy requirements that conflict with the new operational realities that arise due to advances in technologies utilized by industry. Collaboration with industry in these instances (such as was done updating the Measurement Directive [D 017] and the development of various subsurface orders) has resulted in the AER successfully addressing legacy requirements to accommodate new technologies.

### **Project Area Disposition – In Situ Oil Sands Development Planning**

Regulatory certainty, in the form of flexibility for optimization of well pad and corridor placement, is required to enable maximized recovery of the resource while minimizing the

surface footprint in the in situ oil sands (ISOS) and for other unconventional development. The systems in place for *Public Land Act* (PLA) dispositions do not support the flexibility necessary to place surface pads within an approved ISOS development and this leads to unnecessary applications and amendments that are directly aligned with the project intent as approved. PADs are necessary to fully enable the IDA approach for oil sands projects.

Work has been underway, and to support this project the AER and AEP have, as of June 2018, agreed to allow progression of a pilot of the PAD approach.

## Recommendations

- Advance the PAD project through the AER in alignment with AEP, IR and AE. This can be achieved initially through the pilot and then rapidly thereafter as an approved approach consistent with IDA and an outcomes-based approach to footprint management.
- Engagement between industry, AER, AEP and other potentially impacted GoA departments such as AE and IR is encouraged to identify any concerns and to ensure that they are addressed expeditiously.

## Master Schedule of Standards and Conditions

AEP rescinded the Enhanced Approval Process Integrated Standards and Guidelines and replaced them with the MSSC while simultaneously applying the MSSC to all aspects of oil and natural gas development in Alberta. Outdated standards and conditions in the MSSC require revision to support effective management of unconventional and oil sands development. Revision to the MSSC will enable routine applications for routine activities, and ensure appropriate focus on activities that are truly non-standard. For example, it is standard practice to drill multiple wells from a single-surface pad to reduce fragmentation and mitigate potential impacts to wildlife. However, this activity is considered non-standard due to the size of the single pad, regardless of the reduction in overall disturbance.

Industry has been engaging with the AER to discuss concerns and required clarifications with respect to MSSC, which are being taken forward to AEP's Standards and Conditions Committee ("Committee") by the designated AER representative. Communication to date has indicated that the oil and natural gas industry's concerns are not aligned with the priorities of the Committee.

## Recommendations

- The MSSC should be critically examined in advance of implementation of the OneStop PLA project. This is critical to the success of IDA. CAPP has identified a significant number of specific areas of concern, including fundamentals for oil and natural gas activities such as road widths and pad sizes required for safe operation and reduced fragmentation, which have been taken forward to the AER.
- A transparent approach to discussions with respect to the MSSC will allow for effective dialogue between industry, the AEP and the AER in order to ensure that the MSSC

addresses environmental and landscape considerations as well as engineering and safety constraints.

### **Sulphur Removal**

ISOS operators must manage sulphur both as a resource, under ID 2001-03, and as an emission stream, under their EPEA approvals. Fluctuating sulphur production rates, coupled with challenging produced-natural gas concentrations of carbon dioxide and mercaptans, make recovery of sulphur, and hence treatment as a resource, non-viable for most ISOS operations. The ISOS industry is seeking a modernization of requirements moving away from regulation of sulphur as a saleable resource and towards management of sulphur dioxide (SO<sub>2</sub>) emissions in accordance with EPEA and the Alberta Ambient Air Quality Objectives (AAAQOs). This will allow industry to drive toward required outcomes and enable selection of best available management approaches while reducing operating costs, waste generation/chemical consumption and trucking.

### **Recommendations**

- Increase the momentum on this file to advance the sulphur removal initiative to realize the objective of managing SO<sub>2</sub> emissions for in situ facilities rather than managing sulphur as a recoverable resource.
- Leverage existing policy and regulatory tools including EPEA approvals and AAAQOs to manage SO<sub>2</sub> emissions for the in situ industry.
- Remove the requirement for in situ operators to manage sulphur in accordance with ID 2001-03.

### **Mine Water Return**

The need for mine water return to the Athabasca River is recognized in the Tailings Management Framework (TMF) to achieve closure and reclamation outcomes as well as reduce liability. Mine water return is necessary to establish a self-sustaining reclaimed landscape that is fully integrated into the surrounding ecosystem and is a well-established practice in the mining industry. Rapid progress on enabling mine water return is required in the next five years to enable the safe and efficient return of water and avoid unintended environmental impacts.

Additional environmental risks are created due to the current lack of regulation to enable mine water return, including:

- Need for additional water storage due to dewatering of tailings resulting in greater disturbance;
- Extended closure timelines due to salt accumulation resulting from continuous water recycling; and,
- Inability for oil sands mines to meet closure and reclamation outcomes.

Mine water return will reduce the risk to government, Albertans and industry, and allow for a more transparent regulatory process for safe water return to the environment.

## Recommendations

- Rapid, continued progression of mine water return requirements, provincially and federally, to enable successful, timely reclamation. Industry continues to require the ability to return water by 2023.
- Recognition that the necessary policy and regulatory tools to enable water return are in place and can, and should, be leveraged to address oil sands mine water return.

### Tailings Management Framework – Mine Financial Security Plan

The current Mine Financial Security Plan (MFSP) review has received input from three key sources:

- A three-year review of the MFSP program into which included industry input;
- A 2015 Office of the Auditor General (OAG) Report; and,
- A 2017 multi-stakeholder group that recommended a Fluid Tailings Performance Deposit (FTPD) as a potential new component to be added to the MFSP to fulfil requirements under the TMF.

Recommended changes from the OAG report and implementation of the FTPD could significantly impact the economic viability of oil sands mining operations. While the GoA has plans to review and update the MFSP, this has been underway since 2014. Although progress has been made, there is a lack of clear direction provided to stakeholders, including industry, and the timelines for completion have not been communicated.

## Recommendations

- Ensure that implementation of the revised MFSP maintains industry competitiveness while appropriately securing liability.
- Continue use of the current MFSP structure with the addition of a representative FTPD cost metric modelled after the Outstanding Reclamation Deposit, and implemented at a cost roughly equal to the cost of treatment of fluid tailings.

### Wetland Policy

The Alberta Wetland Policy was released in 2013 and has been in effect since July 2016, but the regulatory processes required to implement the policy for oil and natural gas activities in the Green Area are still under development. The current policy focus has led to a significant number of tools, checklists, directives and guides that are complex to navigate. Over the last year, AEP and the AER have made considerable efforts to provide the clarity and consistency requested by industry through multiple information sessions, issuing FAQs and testing proposed language for clarity when updating policy documents. Ongoing implementation concerns relate to historical exemptions for projects predating the policy, and policy integration with EPEA requirements and *Water Act* approvals.

The policy design is such that site-level wetland assessment and mitigation are required for all wetlands regardless of value, which has created significant regulatory burden and reclamation liability for industry. Costs will be especially high for new oil sands projects. CAPP's position has consistently been that a regional approach to focus management on high-value wetlands would be more practicable in the Green Area, where wetlands are abundant.

## Recommendations

- Review the Alberta Wetland Policy to determine if a simplified regional approach, where wetland assessment and mitigation efforts are focused on high-value wetlands, would achieve the same (or better) outcomes for wetlands with less regulatory burden and costs to industry.

### 6.1.5 Liability Management

The commodity price collapse in 2014 coupled with the 2017 Redwater decision<sup>29</sup> resulted in the proliferation of orphaned upstream oil and natural gas infrastructure and exposed deficiencies in provincial liability management regulatory and policy frameworks. Alberta initiated a liability management review in early 2017 that resulted in extensive stakeholder engagement and is expected to culminate with government announcements in the fourth quarter of 2018. While some progress has been made on elements of the liability management system, there are opportunities to ensure the framework protects the environment, stakeholders, and industry.

#### Liability Management System Enhancements

The GoA's liability management review engagement was completed in late 2017. CAPP's submission to the review included 11 recommendations in three strategic areas – enhanced inactive site closure, a modernized liability management program, and development of a well assurance program. CAPP is currently awaiting the outcomes of the GoA's review including recommendations.

In parallel with the review process, the AER is collaborating with CAPP, the Explorers and Producers Association of Canada (EPAC), and the Petroleum Services Association of Canada to develop a framework to operationalize ABC for 2019. The program will initially be voluntary but is expected to align with the recommendations of the government review. While certain elements of the existing system have been effective, given the pressure on industry due to continued commodity price challenges and recent court decisions, there are areas that could benefit from enhancements. Most recently, concerns regarding the potential impacts of transfers of assets to and between higher-risk operators has been of concern to CAPP

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<sup>29</sup> The May 2016 Alberta Court of Queen's Bench ruling in favour of bankrupt company, Redwater Energy. The ruling determined profits from asset sales would go to creditors before covering the cost of cleaning up inactive sites.

members. To address this, CAPP has developed a proposed transfer administrative process for consideration by the AER and government.

## Recommendations

An effective liability management system must protect Albertans and industry from undue risk from current and future liability; protect the environment, people and communities; and, maintain economic growth and competitiveness. CAPP recommends:

- Strategic pillars that would benefit from enhancements include inactive site closure, modernized liability management program, and a well assurance program.
- Consider enhancements to the license transfer stringency process to ensure asset transfers are not creating undue risk. Enhancements should manage risks to and ensure sustainability of the Orphan Well Fund.
- Predictive system for determining the need for security (consider operator financial health and credit risk, along with company practices for reducing inactive liability).
- Governments and regulators should review the current regulatory requirements regarding closure and liability to ensure that requirements are risk-informed (particularly for sub-surface wellbore decommissioning and surface reclamation and remediation). To this end, CAPP recommends implementation of a number of “big rock” opportunities to enable more cost-efficient closure, including:
  - Allowing commingled abandonments under certain circumstances;
  - Reviewing abandonment requirements for wells in oil sands regions (with non-completed oil sands zones);
  - Allowing alternative approaches to manage low-rate surface casing vent flows and/or gas migrations;
  - Consideration of low-probability receptor / native prairie protocol approaches to reclamation and remediation;
  - Review default assessment values for drilling waste;
  - Inter-industry alignment of reclamation criteria for forested lands; and,
  - Provide alternative approaches for disposition amendments at the time of reclamation.

### Orphan Well Association Levy Increases

Currently there are about 3,000 orphaned sites, most of which were orphaned since 2013. The Orphan Well Association has estimated the liability of sites already designated as orphans is approximately \$500 million and a further potential of \$800 million from firms currently in the insolvency process. Orphan levy costs are expected to rise in 2018, followed by an increase to \$60 million in 2019-2020 – up 33 per cent from \$45 million in 2018-2019 and double the \$30-million levy in 2017-2018. Continued increases in the orphan site inventory underscores issues with the current liability management framework.

## Recommendations

- Liability management system changes as detailed for the Liability Management System Enhancements (above) are required to reduce orphan risk into the future.

## 6.2 Indigenous Engagement on Policy and Regulatory Initiatives

Engaging with Indigenous communities has been, and continues to be, a priority for the energy sector. Canada's oil and natural gas industry supports the principles outlined in the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and was one of the first industries to endorse its implementation in a manner consistent with the Constitution of Canada and the country's laws.

CAPP is committed to engaging and working with Indigenous communities, and supporting Indigenous self-determination and prosperity. However, the GoA is advancing engagement with Indigenous communities on a number of policy and regulatory initiatives that have significant implications for the oil and natural gas industry. These initiatives need to be considered from an integrated strategic, collaborative perspective and include:

- Indigenous Consultation Policy renewal;
- Process integration/regulatory reform between IR, AER and AEP;
- Draft Moose Lake 10-kilometre Management Zone Plan;
- Lower Athabasca Regional Plan (LARP) five-year review; and,
- Oil Sands Monitoring Operational Framework Agreement.

While development of the Oil Sands Monitoring Operational Framework Agreement represents a positive example of industry engagement, these policy and regulatory initiatives taken as a whole, are of concern to industry as the province is advancing them under ambitious timelines and is not sufficiently engaging industry in the process, or considering these matters from a broader, strategic context. As a result, there is the potential for unintended consequences, including increased burden to Indigenous communities, additional onus on government and regulators, and potential impacts to investor confidence, industry competitiveness and job creation in Alberta.

## Recommendations

- Engage with industry as part of an inclusive approach to allow for identification of potential unintended consequences as the government moves forward on regulatory and policy initiatives bilaterally with Indigenous communities.
- Leverage multi-stakeholder frameworks and opportunities to increase transparency and promote inclusiveness with regards to engagement to ensure representative discussions considering all aspects and potential implications of proposed policy and regulatory reform.

### 6.2.1 First Nation and Métis Settlements Consultation Policy Renewal

Since the release of CAPP's 2017 Alberta competitiveness report, there has been active engagement on Indigenous Consultation Policy renewal. Industry's position has been that fundamental changes to the policy are not required and that improved performance is needed under existing policies. Concerns with the policy renewal process, as raised by industry, include:

- The ideas proposed in the policy renewal will increase the consultation burden on industry and increase timelines, but do not address performance challenges.
- The policy renewal process has not effectively transitioned from high-level ideas to policy proposals with sufficient detail to inform the policy renewal process.
- Meaningful, detailed dialogue between government, Indigenous communities and industry throughout the process has been absent.
- The potential to expand the matters/activities subject to consultation could significantly increase costs associated with consultation in Alberta, and the expectations of Indigenous communities in the consultation process.
- The policy renewal is occurring in isolation from other government initiatives and priorities.

## Recommendations

- Advocacy and messaging has remained consistent throughout the policy renewal process. Industry continues to support the need for improved performance within the ACO and the AER. For example, the establishment of concurrent processes between the ACO and AER would significantly increase the efficiency of the regulatory process. Addressing these objectives can positively influence other priorities CAPP and its members have identified throughout the policy renewal.
- Broader engagement and advocacy to include other ministries such as AE, AEP, and Economic Development and Trade, is required to ensure that the policy progresses in a manner that is consistent and improves ACO performance and competitiveness.

## 7 Climate Policy

Canada's oil and natural gas industry is supportive of climate policies that are effective and efficient, and take into account cumulative impacts. With the right policies, Canada can be competitive, attract investment, spur innovation and reduce emissions.

However, current climate policies are inefficient and are adding to unintended consequences that drive investment away from Canada. In general, government policies need to:

- Take into account the current economic environment for the oil and natural gas sector and continue to work with industry to develop regulations that help reduce emissions while still allowing for the continued growth of the Canadian oil and natural gas sector.
- Create protection mechanisms for EITE sectors to help avoid carbon leakage.<sup>30</sup> These mechanisms need to include small and large producers.

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<sup>30</sup> Carbon leakage occurs when one country's emissions reductions policies lead to increased production in another country with less stringent regulations. The net effect is that carbon emissions do not decrease and at worst, rise due to less stringent regulations in other countries.



- Assess all costs and recognize the cumulative burden of any policies and regulations, corporate tax increases and royalty changes.
- Return carbon-related revenue to EITE industries through revenue recycling and innovation funding. By re-investing carbon revenue into EITE sectors, governments can help protect the competitiveness of internationally trade-exposed industries, create incentives to reduce emissions, and help unlock step change technologies.

## 7.1 Methane

CAPP supports a flexible, results-oriented, and streamlined approach to reducing methane emissions that also stimulates technology and innovation, and ensures Alberta can be competitive. The methane reduction target of 40 per cent to 45 per cent by 2025 is expected to increase both capital and annual operational costs. CAPP has provided recommendations to government on how to achieve the target with minimum impacts on employment and the economy.

In 2018, the GoC finalized methane regulations for the upstream oil and natural gas sector which, by government estimates, will cost industry \$3.9 billion from 2018 to 2035. The GoA has also issued draft methane regulations which could take the place of the federal regulation within the province. CAPP recognizes the efforts of the Alberta government to implement a more tailored and cost-effective approach to reducing methane when compared to the federal regulations. The expected cost of the regulations is around \$780 million from 2018 to 2025.

### Recommendations

- Provide details on the provincial equivalency of the federal regulation.
- Reduce the leak detection and repair (LDAR) frequency for sweet natural gas plants and sweet compressor stations to once per year.
- Exempt Cold Heavy Oil Production with Sand (CHOPS) wells without controls from LDAR. Involve industry in co-developing the appropriate methane manuals (estimating and reporting, fugitive emissions management) in order to ensure the most cost-effective design.

## 7.2 Carbon Pricing

Carbon pricing, short-term and long-term, will lead to increased costs due to pricing on electricity and fuel consumption, as well as the ramping up of the carbon tax to \$50 per tonne by 2023, respectively. Industry's concerns with the policy have not advanced in the last year.

### Recommendations

- In the short-term, continue to exempt non-large final emitters under new federal carbon policy until 2023.
- In the long-term provide mechanisms to protect non-large final emitters post 2023 exemption.
- Provide protection for EITE through use of opt-in mechanisms for non-large final emitters into the OBA system.

### 7.3 Carbon Competitiveness Incentive Regulation

The GoA moved to a carbon competitiveness incentive regulation (CCIR) approach in 2017. Under the CCIR performance standard for large-emitting facilities there are benchmarks based on Alberta's facilities restrictions imposed on the use of offsets to meet compliance obligations and are tests to enable cost containment programs for facilities. Nonetheless, there are a number of ongoing items that CAPP offers as input to ensure that climate policy can be implemented in a manner that considers and protects the EITE industry's outstanding challenges with the CCIR to ensure we are able to be competitive with other leading climate policy jurisdictions.

#### Recommendations

- Use three-year average of data for setting the mining benchmark.
- Adjust benchmark to include fugitives in setting the benchmark for mining.
- Include allowance for solvent recovery units for stand-alone mines.
- Implement/adjust the CCIR approaches in a manner that considers and protects the EITE industry and ensures competitiveness with other jurisdictions, including separate OBAs for in situ developments based on regional characteristics.
- Remove the limit on use of offsets and emissions performance credits and enable full use of offsets for compliance characteristics.
- Finalize natural gas processing and upgrading benchmarks.
- Ensure the cost containment program is available to facilities that receive an unacceptable burden from the climate program.

### 7.4 Oil Sands Emissions Limit

The method by which the 100-megatonne (MT) emissions limit on oil sands will be implemented has created investor uncertainty pending the release of the emissions limit policies. There has not been much movement on the file since the Oil Sands Advisory Group recommendations were released. If government is planning on advancing additional regulations related to this file, the need to ensure investor confidence is more important than ever.

#### Recommendations

- Ensure flexibility and keep all options open including offsets in managing the sector's emissions during scarcity.
- Establish a framework that prioritizes investment in technology.
- Industry requests engagement on any proposed regulations related to the implementation of the emissions limit.

## 8 Fiscal and Economic Policy

The tax and fiscal regime can have a substantive impact on the competitiveness of the industry, particularly relative to other jurisdictions that compete for investment. While the deductibility schedules for capital investment for tax purposes is the purview of the federal government, there are a number of fiscal levers available to Alberta that can substantially enhance competitiveness.

### 8.1 Royalties

Oil and natural gas royalties are part of a larger fiscal system that drives investment, creates jobs, and generates government revenues. In the recent modernization of Alberta's royalty framework, the introduction of the Drilling and Completion Cost Allocation, or C\*<sup>31</sup> cost deduction, as part of the conventional framework, was an important change in recognizing costs of development and need for competitiveness, including encouraging investment in emerging plays. However, industry engagement on design tenets of the Modernized Royalty Framework (MRF) such as the Emerging Resources Program (ERP) and Enhanced Hydrocarbon Recovery Program (EHRP) will be key in ensuring objectives are met. Specifically, those objectives of providing appropriate royalty treatment for emerging oil and natural gas resources that are high cost and high risk, resources that are difficult to access and produce, promoting innovation to incent development, and generating incremental royalty revenue for Albertans over the long-term.

With respect to the oil sands, while the modernization resulted in some improvements to the royalty structure including clarity to some of the rules, it did not address some of the shortcomings within the current framework that create a fiscal deterrence to investment. Specific examples include:

- The quality deduction (\$0.69 per barrel)<sup>32</sup> within the current Bitumen Valuation Methodology (BVM) should reflect the sale price of bitumen, which would otherwise be included in third-party, fair market value dispositions.
- Current gross royalty is based on a sliding scale that is tied to West Texas Intermediate (WTI) oil prices and takes a value of between one-per-cent and nine-per-cent. Gross royalties create a barrier to new investment by collecting revenues from projects which have yet to achieve payout and prior to the realization of any economic rent which results in a sub-optimal development plan.<sup>33</sup>
- Research costs are considered eligible under the oil sands royalty (OSR) regime only if “reactive type” research is conducted to solve problems of immediate applicability for the recovery, production, or processing activities for that specific OSR project. This precludes a significant amount of R&D spending and creates a disincentive for producers to collaborate. For example, the majority of Canada's Oil Sands Innovation Alliance

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<sup>31</sup> C\*, also known as the Drilling and Completion Cost Allowance, represents completed well costs. C\* is expressed as a dollar amount. The royalty rate is a flat 5% until the cumulative revenue generated by a well equals its C\*, after that royalty rates will be based on a sliding scale based on commodity prices and well production.

<sup>32</sup> Currently set to expire on Dec. 31, 2019.

<sup>33</sup> Garnaut, Ross, Ross, Anthony Clunies. *Taxation of Mineral Rents*. Oxford: Clarendon Press, 1983.

(COSIA) research costs are not currently eligible as allowed costs because they are not directly attributable to any single OSR Project.

## Recommendations

- Re-evaluate the BVM used for valuing bitumen in non-arms-length sales. The BVM should be principle-based and should reflect the fair market value of quality adjustments including TAN and sulphur as well as “other value erosion characteristics of the bitumen barrel.”<sup>34</sup> The BVM should also reflect the average transportation allowance to deliver the bitumen from the project to Alberta markets.
- Reduce maximum oil sands gross royalty to three-per-cent from nine-per-cent and prorate the related oil benchmark price sliding-scale calculation accordingly.
- Recognize R&D expenses through an AE OSR credit set at 25 per cent of every dollar of otherwise OSR ineligible oil sands R&D costs spent to offset OSR payments. This OSR credit should be applied to reduce an OSR project operator’s OSR payable on any of its chosen affiliated OSR projects.
- Industry and government collaboration on royalty program improvement, such as the ERP and EHRP.

## 8.2 Value Add

The energy industry is committed to being a global leader in environmental performance through innovation and by sharing advances in technology for use around the world. Responsible energy development, driven by technology, is critical – not only to the future of the sector but the future of the Canadian economy. CAPP has been engaging with the federal government to advance competitiveness as a priority. Through this process, a role for provincial governments have been identified to remove barriers to new technologies.

### Natural gas

Innovation is fundamental to how companies in the LRNG sector do business. Boosting innovation correlates with economic, social and environmental benefits, including a healthy technology sector, and benefits extend to diversification and synergies with other industries (i.e., transfer of technologies outside of the oil and natural gas sector). The synergy between LRNG and emissions-reduction technologies is important to the Canadian economy. The LRNG innovation system is lacking in capacity and co-ordinated action on R&D, compared to the oil sands sector and LRNG in the U.S. Further, infrastructure challenges also act as a barrier to achieving operational innovation.

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<sup>34</sup> AE, Alberta’s Partial Upgrading Program. Alberta Energy. July, 2018.

## Recommendations

- Support the establishment of an industry-led task force to develop a collaborative approach towards LRNG-focused R&D, an overarching innovation strategy (program design and intent), alternative structures and potential mechanisms to access government funding support.
- Build on the results of the Regional Electricity Cooperation and Strategic Infrastructure Initiative study and examine upstream oil and natural gas electrification opportunities to address economic risks, infrastructure constraints and possible funding mechanisms.

### Oil Sands

Moving the needle on oil sands competitiveness is a requirement to driving new technology in the sector. Significant opportunities exist for industry and government to work together to meet a common goal of responsibly optimizing the value of Canada's vast resource and future growth.

In February 2018, the energy industry was encouraged by the provincial government's announcement to financially support \$1 billion in partial upgrader capacity for bitumen produced by Alberta's oil sands. Partial upgrading is a new technology on the horizon that will add value to the oil produced in Alberta, ease pipeline constraints by reducing diluent requirements, and decrease wells-to-refinery GHG emissions.<sup>35</sup>

## Recommendations

- Streamline project approvals and regulatory timelines which would enable the implementation of new technology.
- Remove barriers to royalties allowed costs for R&D.
- Recognition of bitumen quality adjustments in BVM for companies to integrate and invest in value-added processes.
- Potential financial levers include immediate deductibility for commercialization of new extraction technology (federal and provincial co-ordination), municipal tax caps (pre- and post-payout), investment/R&D tax credits, favourable financing terms/access to capital.

### 8.3 Municipal Taxation

Local taxes are the second-highest cost to the oil and natural gas industry provincially, after royalties. In September 2017, the Regional Municipality of Wood Buffalo (RMWB), which has the highest residential to non-residential tax-rate ratio, in collaboration with the Oil Sands Community Alliance, submitted a 10-year plan for reaching the 5:1 ratio. The "made in Wood Buffalo" plan is designed to be incremental and allows time for all taxpayers to adjust to the changing financial demands of the RMWB. Having a plan that identifies a predictable tax rate over the next 10 years and lowers the burden on industry will significantly make the region

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<sup>35</sup> University of Calgary, Public-Interest Benefit Evaluation of Partial-Upgrading Technology, 2017.

more competitive and help bring investment back. However, the file has not advanced as the GoA has not formally implemented the plan in regulation as envisioned in the Modernized Municipal Government Act (MGA).

In 2017, the proposed Regulated Industrial Property Assessment (RIPA) Ministers Guidelines, set to replace the Construction Cost Reporting Guideline (CCRG), was intended to be a clarifying document for industrial property assessment. However, the initial draft represented a significant policy shift and expansion in assessment, which would have resulted in an annual increase of approximately \$70 million in property taxes to industry. The final draft of RIPA will be finalized in the third quarter of 2018.

In late 2017, Assessment Year Modifiers (AYM) were frozen at 2016 levels until models are improved with industry engagement to ensure AYM properly reflect changes that have occurred in the costs of constructing regulated industrial property. The initially proposed cost adjustment from the Assessment Services Branch would have resulted in an incremental tax burden of \$30 million to industry, which is a conservative estimate. Conversely, the actual costs from activity on the ground indicated a \$20-million reduction, which constitutes a discrepancy of \$50 million between what was proposed and industry actuals.

Ensuring the provincial AYM accurately reflect actual construction cost reductions achieved in this extended downturn is critical as the value of industry's assets must be appropriately reflected, thereby avoiding unnecessary property tax increases.

In mature fields, the lack of appropriate depreciation schedules for older or underutilized wells and pipelines results in property taxes becoming a very high proportion of operating costs and therefore becoming a driving force behind premature abandonments and shut ins. The 2018 assessment model reviews need to incorporate depreciation schedules that allow operations to reasonably continue, thereby continuing to provide jobs, royalties, and municipal revenue.

Further, effective in 2018, the GoA added a new levy by way of the Designated Industrial Property Tax Rate. This levy applies to designated industrial property owners through a separate tax rate applied to every designated industrial property owner's municipal tax notice. Historically, municipalities were responsible for their own assessment of industrial properties. This new levy represents a shift of this cost and function historically borne by municipalities onto industry.

## Recommendations

- In line with the MGA, pass regulations detailing the compliance timelines for non-conforming municipalities to reach the 5:1 ratio.
- Ensure the final RIPA guideline is a clarifying document, not a policy shift in industrial assessment from the CCRG resulting in increased assessment and taxes.
- Extend the 2017 freeze into 2018 for Pipelines and Machinery & Equipment until the AYM model review is completed with industry input. The 2018 AYM changes for wells should reflect a six-per-cent decrease.

## 8.4 Corporate Income Tax

In Alberta, oil and natural gas corporations are taxed at the same basic rate as other corporations and, in general, there is not a special tax regime for oil and natural gas producers.<sup>36</sup> From 2002 through 2016, no sector contributed more via corporate tax to GoA revenues than oil and natural gas.<sup>37</sup> Studies have shown that the tax treatment of oil and natural gas companies is such that they actually face a higher marginal effective tax rate (after including the effects of royalties, etc.) than other sectors in Canada.<sup>38</sup> In addition to federal and provincial corporate income tax, personal income tax, provincial royalties, and various sales taxes, oil and natural gas companies also pay a number of other levies such as various land fees, land rentals, land bonuses, municipal property taxes, among others.

**“A reduction in Alberta’s corporate tax rate back to 10-per-cent from 12-per-cent, alone, would increase the value of a generic 35,000 b/d in situ facility by approximately \$13.6 million.”**

In 2015, the GoA increased the corporate income tax rate to 12-per-cent from 10-per-cent. Canada’s corporate tax rate was once a hallmark of our competitiveness as a jurisdiction. However, with tax increases in Alberta coupled with tax reductions in the U.S., this is no longer the case. The combined federal and provincial corporate income tax rate for Alberta is 27 per cent, while the average U.S. combined federal and state corporate income tax rate is now 25.75 per cent<sup>39</sup>. Texas, which draws the bulk of U.S. oil and natural gas investment, has zero corporate tax rate therefore companies only pay a federal rate of 21 per cent.

Last year’s tax reform in the U.S. induced a global reaction, with more tax reforms likely to follow. In a reaction to this U.S. policy shift, Japan, Russia, and China all announced significant tax reforms in late 2017.

A reduction in Alberta’s corporate tax rate back to 10-per-cent from 12-per-cent, alone, would increase the value of a generic 35,000 b/d in situ facility by approximately \$13.6 million.

## Recommendations

- Return the Alberta corporate income tax rate to 10-per-cent from 12-per-cent.

<sup>36</sup> Ernest and Young, Global Oil and Natural gas Tax Guide, 2017.

<sup>37</sup> GoA, Corporate income tax revenue. <https://open.alberta.ca/opendata/net-corporate-income-tax-revenue>

<sup>38</sup> Bazel, Phillip, Mintz, Jack, Whether it is the U.S. House or Senate Tax Cut Plan-It’s Trouble for Canadian Competitiveness. 2017

<sup>39</sup> Grant Thornton, Tax reform is finally here. What do we do now? 2018.

## 8.5 Workplace Legislation Review

The GoA has made changes to the Labour Relations Code and reviewed the *Worker's Compensation Act*. It is important that labour policy recognize the unique nature and realities of the oil and natural gas industry and enables continued economic prosperity and competitiveness.

### 8.5.1 Bill 17: Fair and Family Friendly Workplaces Act

The GoA made changes to Alberta Labour Relations Code and Alberta Employment Standards Code ("Code") in Bill 17. Some of these changes will significantly affect industry and create administrative burden and increased cost without adding any additional protection for employees.

CAPP members have been working with the government on a variance for the oil and natural gas industry pertaining to certain sections of the Code. The variances help address the realities of, and provide the flexibility needed for, the rotational work schedules in the oil and natural gas industry, as well as meet the underlying intent and principles of the Code. However, creating permanent industry-specific regulations to support the Act presents a more efficient solution that benefits employers and employees as well as reflects today's employment realities and needs.

### Recommendations

- It is important that the province develop labour policy that enables continued economic prosperity and competitiveness. In the short-term, it is recommended to promptly grant a variance for the oil and natural gas industry.
- In the long-term permanent, industry-specific regulations should be created to support the Act.

### 8.5.2 Bill 30: Act to Protect the Health and Well-being of Working Albertans

The government has undertaken a comprehensive review of Alberta's Occupational Health and Safety system and *Workers' Compensation Act*. The legislative changes came into force on June 1, 2018. The safety of employees, contractors and the public-at-large is industry's first priority. CAPP has been fully engaged in the review and looks forward to further engagement with the regulators to improve occupational health and safety and be proactive in protecting the health and safety of workers. However, industry does have concerns, broadly organized into themes of roles and responsibility, worker engagement and prevention activities.

### Recommendations

- Provide more clarification on the responsibilities and obligations for employers as well as work with employers on the details of the revised reporting requirements.



## 9 Resource Access

The government is currently engaging in a number of policy and regulatory initiatives that create risk or unnecessary limitations for industry in terms of its ability to access the resource. These types of initiatives create barriers to development and/or uncertainty which have the potential to jeopardize the economic viability of potential investments. Issues such as caribou habitat recovery, lease tenure policy, land-use planning and oil sands monitoring all create some level of risk in terms of predictable, timely, and cost-effective surface access in order for industry to develop subsurface oil and natural gas resources.

### 9.1 Caribou Range Planning and the Species at Risk Act

In December 2017, the GoA released its draft Provincial Woodland Caribou Range Plan, addressing declining caribou populations while considering economic growth within the province. The oil and natural gas industry has a track record of contributing ideas, technologies, research and action to caribou recovery efforts and wants to keep building on that commitment and momentum. Alberta has extended effort on broad range planning to accommodate detailed socio-economic analyses for each range and has also acknowledged its role in funding for restoration of legacy seismic footprint. The federal government has committed to a shared partnership in funding of restoration in Alberta.

The best path to success is through an inclusive and co-ordinated effort involving all land users. A concerted effort involving all stakeholders and Indigenous peoples is required to develop and implement recovery measures within all caribou ranges. This will ensure a realistic, collaborative and practical approach that can help boost caribou populations while at the same time protecting jobs and providing certainty to communities and industries.

As a broad outcome of caribou range planning, industry has consistently advanced the need to build and maintain a working landscape in caribou ranges. Maintenance of a working landscape inclusive of the upstream oil and natural gas industry achieves two outcomes:

- Provides clear rules to guide compatible development in caribou ranges; and,
- Maintains competitiveness and profitability of oil and natural gas operators in caribou ranges.

### Recommendations

- Reduce or eliminate the risk of federal intervention on land use in Alberta's caribou ranges.
- Maintain the current focus on socio-economic impact analysis to inform effective range planning and sustained implementation.
- Work with industry and the federal/provincial governments to advance a working landscape<sup>40</sup> approach to restore caribou habitat while maintaining oil and natural gas development.

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<sup>40</sup> A working landscape is an area of land managed for multiple environmental, social and economic objectives.

- Ensure cost certainty associated with caribou recovery actions, with costs distributed equitably among key land users in caribou ranges and governments.
- Enable industry participation in an oversight committee with a mandate that includes determination of priority restoration zones, annual assessment and allocation of funds to habitat restoration and rearing facilities.
- Reduce regulatory costs and improve timelines associated with accessing resources in caribou ranges.
- Improve flexibility in tenure requirements to align business development needs with reduced footprint.

## 9.2 Lease Tenure

The current lease tenure system needs to better reflect how conventional and oil sands development projects occur.

For the oil sands, modernizing the lease tenure system has been identified as a priority for both industry and government. Industry would like to see government establish consistent, efficient, effective, and enduring regulation in order to ensure the responsible and orderly exploration, development and production of Alberta's oil sands.

Industry is seeking to work with AE to update the oil sands tenure system to reflect the realities of oil sands operations, to allow companies to deploy their capital on their leases more efficiently, and reduce their environmental footprint in a manner that aligns with the government's overall energy, environment and economic policies. A clear, simple, aligned and sustainable oil sands lease tenure system will help attract and sustain investment in Alberta's oil sands.

For the conventional side, in mid-2017, CAPP provided AE with a proposal outlining consensus CAPP/EPAC short-term mineral tenure change opportunities, which was put on hold due to multiple conflicting priorities. While tenure has been raised as an area to advance via the AER Regulatory Efficiency initiative, there has been no movement to date.

## Recommendations

- Oil Sands: adopt a lease tenure approach that allows companies to more efficiently survey their holdings as opposed to prescribing the minimum level of evaluation per lease.
- Ensure any changes to the oil sands lease tenure policy be consistent and aligned with other government energy, environment and economic policies such as caribou recovery, Climate Leadership Plan, LARP and the provincial royalty framework.
- Enable companies to effectively deploy their capital and develop leases in an orderly and staged fashion though the enabling of grouping of leases to align with project development plans.

- Ensure any reforms to escalating rentals encourage the development of oil sands projects without substantially increasing costs, continue to enable offsets and ensure any reforms are transparent, and predictable.
- Conventional: AE to implement short-term mineral tenure change opportunities that have been supported by both CAPP and EPAC.

### 9.3 Land-use planning

Land-use planning can be used to identify and prioritize values (economic, social, cultural, and environmental) and establish a process to detect and manage emergent pressures on those values. Land-use planning is a fundamental component of modernizing regulation in Alberta and key to balancing the desired outcomes for industry, government, stakeholders and Indigenous communities.

Land-use planning can also establish administrative boundaries for consultation. Land use plans can then be used by the ACO to properly define the types of activities/applications that trigger the need to consult and then address statements of concern in relation to treaty rights and traditional use.

#### 9.3.1 Alberta Land Use Framework

In 2008, the GoA introduced the Land Use Framework, which is intended to guide land managers and natural resource decision makers in how best to manage growth in Alberta. The first regional plan out of the Land Use Framework was the LARP.

The LARP is an example of initial progress towards leveraging a land-use planning approach to guide regulation in Alberta. Under the LARP, industry, government, stakeholder and Indigenous communities are able to work collectively towards alignment on intended outcomes for environmental management in the region. Plans such as the LARP can, and should, be leveraged for managing and monitoring oil and natural gas development in conjunction with other landscape users. That said, key elements of the LARP have yet to be completed (e.g., the Biodiversity Management Framework), and industry has not been informed on the current status of the ongoing LARP review. Uncertainty exists within industry on what may arise out of these outstanding outcomes and processes. Transparency and engagement with industry will go a long way to reducing this uncertainty.

### Recommendations

- Completion of all elements of LARP as that is critical to provide the certainty necessary for future oil sands development.
- Develop regional plans that achieve defined social, economic and environmental outcomes beneficial to Albertans and Indigenous people through predictable resource access and the active management of landscapes to provide assurance of responsible resource development that is supported by a system of management capable of addressing cumulative effects to land, air and water.

- Provide confidence in regional plans and associated land management tools can be used as a means for fulfilling obligations under federal SARA legislation (i.e., Section 10 – stewardship, Section 11 – recovery).
- A functioning LARP multi-stakeholder engagement process that enjoys the support of all stakeholders is essential to the credibility of provincial regional planning and to support future oil sands development.
- Provide clarity on the linkage between monitoring to support LARP’s environmental management frameworks with monitoring being undertaken by Oil Sands Monitoring (OSM) in the oil sands region.
- Re-affirm the role of regional planning in the management of cumulative effects through periodic progress reports describing efforts made to implement LARP and South Saskatchewan Regional Plan and advance the North Saskatchewan Regional Plan and other plans.

### 9.3.2 Moose Lake Access Management Plan

AEP released the draft Moose Lake Access Management Plan (MLAMP), which contained strict resource access constraints with a high potential to sterilize resources. The MLAMP is an example of a provincial policy that creates additional investor uncertainty for the oil and natural gas industry. The original intent of MLAMP was to minimize disturbance by managing access. It is now a comprehensive approach to managing oil and natural gas operations, in an area already allocated under LARP as a mixed-use area. The restricted development zones are beyond the legislative authority and intent of LARP.

MLAMP will set a precedent to enable Indigenous communities and other stakeholders to request similar restricted development zones. This has the potential to further decrease investor confidence in Alberta’s oil and natural gas sector and result in substantial economic ramifications for industry, the province and the governments of Alberta and Canada. CAPP members estimate that there is a total of 2.6 billion barrels of recoverable resource that lies within the 10-km zone. Developing this resource to its potential would result in \$27 billion in government revenue (federal and provincial) over the lifetime of the resource.

## Recommendations

- Sub-regional plans (including MLAMP) should always be developed transparently using established land-use planning principles and process, and demonstrate consistency and computability with the broader LARP, Landscape Management Plan and environmental management frameworks. MLAMP should focus on issues that were not directly addressed by LARP, including access management and surface disturbance limits.
- Implementing the Draft Plan in its current state raises unintended consequences and serious concerns regarding setting a precedent and risk of sterilizing bitumen development which is contrary to the principle stated in the draft plan that “bitumen development will not be sterilized.”

## 9.4 Effective Oil Sands Monitoring and Reporting of Impacts

Industry and government share a common goal of implementing monitoring systems that are integrated, effective and efficient and have the confidence of all stakeholders. Currently, industry pays \$50 million annually for the joint federal-provincial OSM program. Industry has been seeking greater transparency and demonstrating an effective use of the \$50 million contribution as well as an optimization of monitoring programs and costs to achieve the OSM goals. In particular, a state of the environment report would be a key output to help provide assurance to the public of the impacts of oil sands development on the environment. The government has made progress on engagement with industry, which has enabled a commitment to action. However, actions to implement the program's original objectives, and to resolve industry's issues with the program have yet to be demonstrated.

### Recommendations

- Provide clear and transparent alignment between OSM activities and monitoring to support cumulative effects management in the oil sands region (e.g., LARP's environmental management frameworks).
- Provide greater transparency on monitoring and research data gathered and faster, more effective reporting. An initial positive step would be to make a report available on the state of the environment and an assessment of progress toward fulfillment of multi-year projects.
- Provide greater transparency on the program budget, program elements, and the annual spend should be offered to all program stakeholders including industry.
- Finalize the OSM Operational Framework Agreement, along with the implementation of a top-down, risk-based work planning process.
- Remove regional monitoring conditions from oil sands facility EPEA approvals to minimize redundancies, eliminate legal ambiguity, reduce monitoring costs and increase efficiencies. This is a key commitment the program 2012 that has yet to be realized.
- Cap revenue from industry at \$50 million, with an expectation that industry's contributions will decrease in the future (as per 2012 funding commitments). All surplus revenue from industry should be returned to industry in a timely manner.

## 10 Benefits of Action

The benefits of governments (both federal and provincial) addressing all these issues are potentially extraordinary. Industry-led modelling suggests the following national benefits: \$20 billion per year of incremental investment; approximately 120,000 additional ongoing jobs (70,000 for LRNG and 50,000 for oil sands); production growth of 50 per cent for LRNG, and 40 per cent for oil sands (or 25 per cent growth above CAPP's current oil sands production forecast); natural gas production growth achieved with GHG emissions intensity declining and GHG emissions essentially flat; and a 20 per cent to 25 per cent decline in oil sands GHG emissions intensity by 2030.<sup>41</sup>

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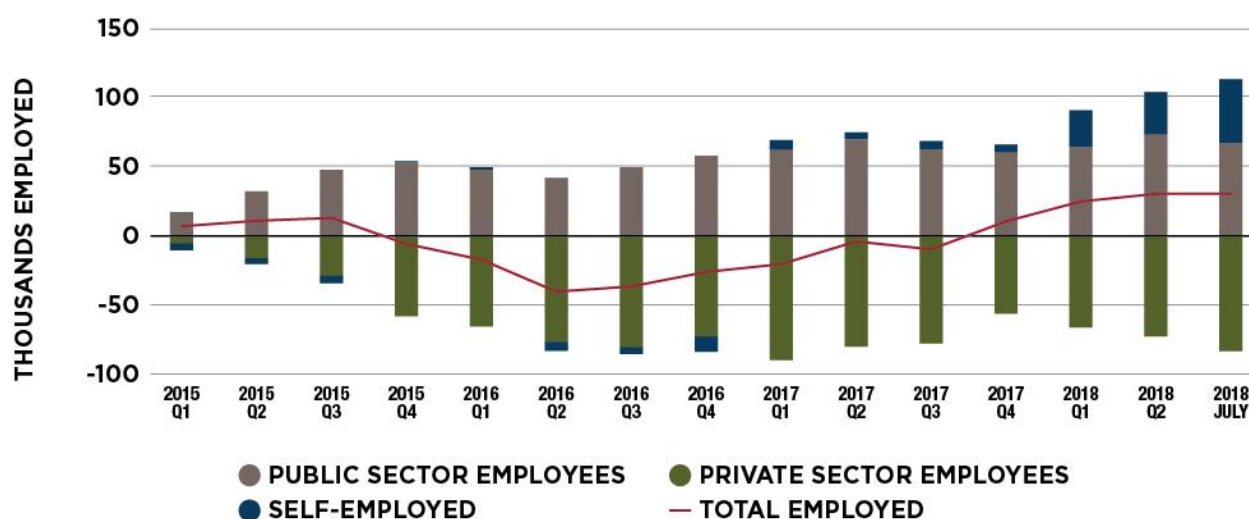
<sup>41</sup> Based on modelling derived from industry-led joint working group analysis.

## Appendix

### A.1. Employment

The increased competitiveness challenges, highlighted above, compound issues for Alberta workers. Alberta's labour force is still suffering from the commodity price crash that happened in 2014-2015. Although economic and jobs growth are rebounding, there continues to be remains concerning trends in Alberta's labour market. On the one hand, all jobs lost since the fourth quarter of 2014 have been recovered. On the other hand, private sector employment has not recovered and self-employment has dramatically increased. As of July 2018, private sector employment remained 84,000 employees below the 2014 fourth-quarter average of more than 1.5 billion.

**Figure A-1: Change in Number of Alberta Employees since Q4 2014 by Class of Employee, Seasonally Adjusted**



SOURCE: Statistics Canada Table 14-10-0288-01

## A.2. Modelling

### Pricing

ITEM	UNITS	ASSUMPTION
FX	CAD / USD	1.20
Inflation	%	2.00%
West Texas Intermediate (WTI)		
Short Term	US\$ / bbl	\$64.40
Long Term	US\$ / bbl	\$60.00
Natural Gas		
With Market Access	US\$ / mcf	\$2.21
Without Market Access	US\$ / mcf	\$1.26
WTI – WCS Differential		
With Market Access	US\$ / bbl	\$13.30
Without Market Access	US\$ / bbl	\$19.00

\*All dollar figures are given in real terms

### Oil Sands

- Oil sands economics assume long-term natural gas pricing
- Oil sands economics are driven by long-term WTI prices:
  - Projects require about four years to reach first oil and produce for about 25 years → current pricing dynamics are not relevant to the investment decision.
  - Long-term WTI chosen on the basis that it more closely reflects the long-term forward curve.<sup>42</sup>

### Unconventional

- Well economics assume short-term pricing inflated at two-per-cent-per-year for wells drilled in July 2018.
- Reflective of short-term pricing dynamics that may be more relevant for shorter cycle projects.

### Tax Assumptions

- a) Flow-Through Taxes: Assumes the company building the project is in a taxable position and can apply the tax pools created by the initial capital outlay toward corporate income rather than income generated by the project.
- b) Depreciation: Capital is eligible for depreciation the year it is spent rather than when the asset is “put-in-use.”

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<sup>42</sup> CME Group, August 13 2018.



## Oil Sands Modelling

### Oil Sands — Generic Facility Assumptions

ITEM	UNITS	CURRENT SAGD TECHNOLOGY	IHA SAGD (INNOVATION)
Nameplate Capacity	bpd	35,000	35,000
Duration of Construction	years	3.50	3.50
Duration of Production	years	26	29
Total Production	mmbbl	295	349
Initial Capital	C\$ MM	1,296.8	1,364.2
Initial Capital	C\$18 / bpd	37,050	38,976
Abandonment Cost	C\$18 / bbl	1.25	1.31
Sustaining Capital	C\$18 / bbl	5.92	6.20
Ongoing Capital	C\$18 / bbl	7.17	7.51
Transportation	C\$18 / bbl	5.50	5.50
Operating Cost	C\$18 / bbl	11.63	11.04
Ongoing Cost / bbl	C\$18 / bbl	24.30	24.05

Source: Wood Mackenzie and CAPP

ITEM	CURRENT SAGD TECHNOLOGY	IHA SAGD (INNOVATION)
SOR		
Year 1	-	-
Year 2	-	-
Year 3	-	-
Year 4	5.00	3.82
Year 5	4.00	3.06
Year 6	3.50	2.67
Year 7	3.00	2.29
% of Initial Capital		
Year 1	15%	18%
Year 2	29%	30%
Year 3	37%	35%
Year 4	19%	17%
Production as % of Nameplate		
Year 1	0%	0%
Year 2	0%	0%
Year 3	0%	0%
Year 4	20%	77%
Year 5	80%	100%
Year 6	100%	100%
Year 7	100%	100%

SOURCE: Wood Mackenzie and CAPP

## Oil Sands — Policy Waterfall Assumptions

CLIMATE ASSUMPTIONS		
Carbon Tax	Existing: \$0.36 / bbl Incremental: \$0.91 / bbl Total: \$1.27 / bbl	<ul style="list-style-type: none"> <li>- Incremental carbon tax only is displayed in the waterfall</li> <li>- Assumes emissions benchmark falls by 1% after 2020</li> <li>- Osum Orion used as proxy and scaled up to capacity</li> <li>- Costs assumed to escalate at an inflation rate of 2%</li> </ul>
Clean Fuel Standards	Existing: \$0.00 / bbl Incremental: \$0.62 / bbl	<ul style="list-style-type: none"> <li>- Assumed competing technology/offset credits available at \$75/T</li> <li>- Cost assumed to escalate at an inflation rate of 2%</li> <li>- Potential for cost to be as high as \$450/T if substituting RNG is regulated</li> </ul>
Methane	Existing: \$0.00 / bbl Incremental: \$0.00 / bbl	<ul style="list-style-type: none"> <li>- Assumed negligible for oil sands</li> </ul>
MARKET ACCESS ASSUMPTIONS		
Differentials	WTI - WCS with pipelines: USD \$13.30 / bbl WTI - WCS without pipelines: USD \$19.00 / bbl	<ul style="list-style-type: none"> <li>- Assumes all incremental barrels feel the full effect of the wide differential for the entire duration of production</li> <li>- Assumes all incremental barrels feel the full effect of the wide differential for the entire duration of production</li> </ul>
OTHER ASSUMPTIONS		
Upstream Regulatory Delay	Assumes 1 year delay Capital costs increased by 3%	<ul style="list-style-type: none"> <li>- 1 year delay does not affect IRR%</li> <li>- Lack of Integrated Decision Approach (IDA) is estimated to increase capital costs of the project by 3%</li> </ul>
Development Risk	<ul style="list-style-type: none"> <li>- Generic facility requires 3 sustaining drilling programs to maintain production over its 26 year life</li> <li>- Modeling potential impact of Caribou / SARA to project economics assumes that the 3rd drilling program is unable to proceed due to an FPO or other stringent regulation. Result is that production falls sooner</li> </ul>	

## Unconventional Modelling

Competitiveness modelling is based on industry-type well data from Wood Mackenzie (production and cost inputs). For each of the selected wells, modelling followed these steps to generate the waterfall. All wells were modelled on a half-cycle basis, with the assumption that the wells were part of an existing program the company was carrying out in Alberta, flowing through the cash flows to the company for tax calculation purposes. No corporate costs were assumed.

1. The starting economics assume the current royalty and fiscal regime and use Wood Mackenzie inputs for capital and operating costs, and production. The economics are measured by IRR (the discount rate required for the net present value of the cash flows to equal \$0) on an after-tax basis (post-tax IRR).
2. Climate policy impact is modelled by adding a variable operating cost (in dollars per thousand cubic feet [mcf]) over the life of the type wells. The climate policies are as follows:
  - CFS at \$75 per tonne (equivalent to 4.5 cents/mcf).
  - Methane abatement cost to comply with methane regulations (equivalent to four cents/mcf).
  - Carbon pricing at \$50 per tonne (equivalent to 21 cents/mcf).

3. Policy and regulatory changes were made in the sequence presented in the waterfalls and represent cumulative impacts of the changes as the graph moves rightward along the horizontal axis.
4. Regulatory delay is modelled by assuming 25 per cent of initial capital is spent in the first year, with the balance of initial capital being spent in the second year and production coming on stream at that point.
5. Resource access risk is modelled by assuming curtailment of production towards the end of the life of a well. After 10 years of production, 20 per cent of production is curtailed.

### Types well parameters

TYPE WELL		DEEP BASIN SPIRIT RIVER	MONTNEY	DUVERNAY KAYBOB FOX CREEK
EUR (thousand boe)	Oil	3.46	114.76	234.96
	NGLs	72.49	258.25	184.83
	Gas	775.10	675.39	528.80
Capital Costs Per Well (C\$ millions, including drilling, completions, equip, and tie in, excluding exploration and acquisition costs)		\$4.5	\$7.0	\$10.5
Variable Operating Costs (\$C/unit)	Liquids (\$C/bbl)	\$2.00	\$9.50	\$7.00
	Gas (\$C/mcf)	\$0.30	\$0.75	\$0.90

### Notes Accompanying the Economic Modelling

It should be noted that the capital costs listed above are to be informative and are listed as the parameters that were run in the economic modelling.

Capital costs can range widely within plays and can depend greatly on geology, product type and the drilling technology being employed. Capital costs can range for the Montney between \$3 million and \$11.5 million, for the Duvernay between \$9.5 million and \$13 million and for the Deep Basin of \$3.5 million and \$9.5 million.

Modelling was completed with half-cycle economics as the data supporting the economic modelling came from the Wood Mackenzie data base. Wood Mackenzie does not include any land costs, exploration, appraisal, etc., nor do they include any G&A. The analysis on data coming from Wood Mackenzie GEM is solely post- FID, so cannot be considered truly full cycle.

### **A.3.Regulatory Timelines in Comparable Jurisdictions**

CAPP conducted a cross-jurisdictional assessment to better understand the approval timelines for well licences in other oil- and natural gas-producing jurisdictions outside of Alberta. The comparison was focused on wells as these require approvals across jurisdictions and can be considered as a baseline for comparison. A comprehensive analysis would need to include aspects related to consultation, Indigenous engagement, land access, associated approval processes, etc., and would require data that is not currently publicly available for all jurisdictions.

#### **British Columbia**

B.C. implemented a new application management system in mid-2016 that includes bundled applications. Application timeline data was acquired from the B.C. Oil & Natural Gas Commission (OGC), and includes closed and pending applications. In 2017, 812 applications were submitted to the OGC. Of these, 35 applications are pending. The median timelines for B.C. from 2016 through 2018 was 44 days. The B.C. application timelines include Indigenous consultation, and applications may be delayed if consultation requirements are not met – regardless of the application type. B.C. has agreed-upon timelines as stated in consultation agreements with First Nations. For example, in the draft interim consultation procedure,<sup>43</sup> timelines could range from 15 to 30 days, depending on the complexity of the application. Taking this into account, in order to enable more of an “apples to apples” comparison to Alberta, B.C. timelines would range from nine to 24 days.

This shift to bundled applications has consolidated applications for activities, which may include wells, roads, pipelines, facilities, geophysical, Water Sustainability Act authorizations, and other upstream industry-related activities. Once an approval is issued in B.C., various reviews for the project are complete and the project can proceed. Conversely in Alberta, a well or facility approval must also be accompanied by one or more of a PLA disposition, a Water Act approval, and/or other approvals under the Oil and Natural Gas Conservation Act, or EPEA, each of which has an associated timeline for review, approval and consultation.

#### **Saskatchewan**

Saskatchewan implemented the new Integrated Resource Information System in 2011, which administers authorizations and applications. Application timeline data for well and facility licences, and enhanced oil recovery was acquired from the Saskatchewan Ministry of Energy and Resources from 2016 to July 2018.<sup>44</sup> The data includes new and amended applications. Pending applications are not included.

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<sup>43</sup> B.C. OGC, Interim Consultation Procedure. Available at <https://www.bcogc.ca/node/13044/download>

<sup>44</sup> It is noted that the number of applications in Saskatchewan is lower than Alberta, and a comparison of the relative resourcing assigned is not available.

## Oklahoma

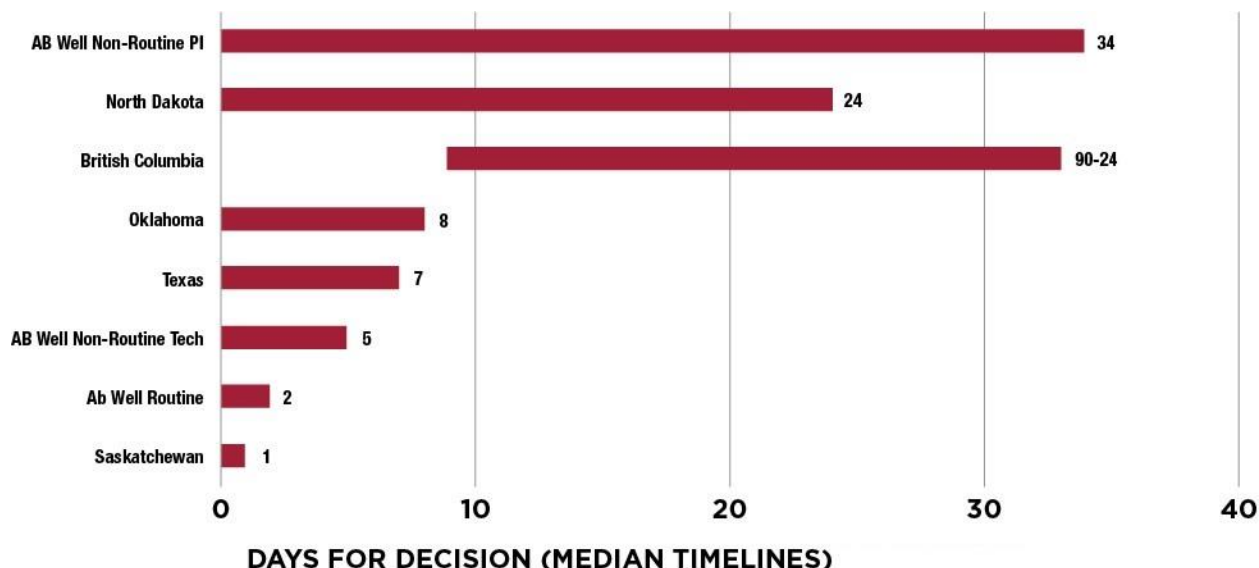
The Oklahoma Corporation Commission, Oil and Natural Gas Division provided well application data from 2015 to 2018. The data includes Intent to Drill (ITD) permit applications. Amended, cancelled, and open applications are not included. In Oklahoma, before an ITD permit application is made, an administrative hearing is required under the Office of Judicial and Legislative Services. The hearing is estimated to take approximately three to four weeks' time. In certain cases, the administrative hearing process can be fast-tracked with a sworn affidavit pre-application, reducing the hearing time to two or three days. However, the hearing time may extend over one year if the request is protested. In 2017, 10,636 applications were processed with a median of 10 days for decision.

## Texas

New drill application data for onshore oil and natural gas wells (including amendments) from 2014 to 2017 was acquired from the Railroad Commission of Texas. Although most applications in Texas are made on private land, timelines increase to several months if the application is made on public land. There are no notification requirements. In 2017, 13,164 applications were processed with a median of nine days for decision.

The figure below plots the median application review timelines for Alberta wells (routine, non-routine technical and PI averaged from 2015 to 2018 against averaged median timelines for Saskatchewan, Oklahoma, Texas, and B.C.<sup>45</sup> In some of the jurisdictions, including B.C., aspects of land acquisition, consultation, Indigenous engagement, water permits, operational licences, et cetera. are included with the well approvals as part of an integrated process.

**Figure A-2: Jurisdictional Comparison of Application Timelines**



<sup>45</sup> The B.C. data includes all applications and the median timelines was 44 days. If you remove the prescribed Indigenous consultation timelines, the range is nine to 24 days for all applications.

## Glossary

AAAQOs – Alberta Ambient Air Quality Objectives  
ABC – Area-Based closures  
ACO – Aboriginal Consultation Office  
AE – Alberta Energy  
AEP – Alberta Environment and Parks  
AER – Alberta Energy Regulator  
AYM – Assessment Year Modifiers  
b/d – Barrels Per Day  
boe/d – Barrels of Oil Equivalent Per Day  
BVM – Bitumen Valuation Methodology  
CAPP – Canadian Association of Petroleum Producers  
CFS – Clean Fuel Standard  
CCIR – Carbon Competitiveness Incentive Regulations  
CCRG – Construction Cost Reporting Guideline  
EHRP – Enhanced Hydrocarbon Recovery Program  
EITE – Energy-Intensive, Trade-Exposed  
EPAC – Explorers and Producers Association of Canada  
EPEA – Environmental Protection and Enhancement Act  
ERP – Emerging Resources Program  
FID – Final Investment Decision  
FTPD – Fluid Tailings Performance Deposit  
G&A – General and Administrative  
GHG – Greenhouse Gas Emissions  
GoA – Government of Alberta  
GoC – Government of Canada  
GoM – Gulf of Mexico  
IDA – Integrated Decision Approach  
IR – Alberta Indigenous Relations  
IRR – Internal Rate of Return  
ISOS – In Situ Oil Sands  
ITD – Intent to Drill  
LARP – Lower Athabasca Regional Plan  
LDAR – Leak Detection and Repair  
LNG – Liquefied Natural Gas  
LRNG – Liquids-Rich Natural Gas  
mmbbls – millions of barrels  
mcf – thousand cubic feet  
MFSP – Mine Financial Security Program  
MLAMP – Moose Lake Access Management Plan  
MSSC – Master Schedule of Standard and Conditions  
MT – Megatonne  
NEB – National Energy Board  
OAG – Office of the Auditor General  
OGC – B.C. Oil and Gas Commission

OSAG – Oil Sands Advisory Group  
OSCA – Oil Sands Conservation Act  
OSM – Oil Sands Monitoring  
OSR – Oil Sands Royalty  
PAD – Project Area Disposition  
PI – participant Involvement  
PLA – Public Land Act  
PNOA – Public Notice of Application  
R&D – Research and Development  
RIPA – Regulated Industrial Property Assessment  
RMWB – Regional Municipality of Wood Buffalo  
SAGD – Steam-Assisted Gravity Drainage  
SARA – Species At Risk Act  
SO<sub>2</sub> – Sulphur Dioxide  
SOC – Statement of Concern  
TMEP – Trans Mountain Expansion Pipeline  
TMF – Tailings Management Framework  
WTI – West Texas Intermediate