PETROLEUM TECHNOLOGY ALLIANCE CANADA

# Needs Assessment for Partial and Field Upgrading

**Final Report**
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# Needs Assessment for Partial and Field Upgrading

## 1. Purpose and Scope

The purpose of the Project is to outline industry needs for partial and/or field upgrading in the oil sands sector. Upgrading is the process of physical and chemical unit operations that converts raw bitumen (extra heavy crude oil) to Synthetic Crude Oil (SCO) which has properties analogous to conventional crude oil. Partial upgrading generally refers to the application of only a subset of such physical and chemical operations to achieve only partial improvement in the upgrading of bitumen to SCO. It is generally intended that partial upgrading takes place in the field near the wellhead for the purpose of achieving the viscosity reduction required for shipment by pipeline.

The Project is an assessment of industry needs and will not delve into specific solutions or technology development opportunities. As such, the purpose of this study is to define challenges and to remain "technology agnostic" with respect to potential solutions. The outcome will be market, performance and cost criteria that would need to be met by any new technology for it to be successful in the application. This will inform the identification and selection of technologies that could be developed and supported by industry and government consortium investments.

The Project included the following tasks:

1. Review of industry literature

Public domain industry and technical literature were reviewed to obtain information about future bitumen production levels and diluent demand, and desired performance and cost criteria for partial upgrading. The review also identified technologies that have been proposed to fill this market need.

2. Consultations with industry

Interviews and consultations were conducted with major oil sands producers to allow them to discuss their needs and expectations.

3. Development of summary market, performance and cost criteria

The information generated in Tasks 1 and 2 was summarized in a list of criteria that should be met by any new partial or field upgrading technology.

## 2. Background

### 2.1. Bitumen Upgrading

Upgraders chemically alter bitumen by removing carbon, adding hydrogen, or both. In upgrading, the sulphur contained in bitumen may be removed, in elemental form and/or as a constituent of petroleum coke by-product. Most oil sands coke recovered of the upgrading process is stockpiled, while small amounts are sold to markets and generally used as fuel to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities associated with the production of sulfur products and fertilizers.

Suncor, Syncrude, Shell, CNRL, and Nexen are the companies that operate upgraders and produce SCO in Alberta. However, the high cost of constructing major projects in Alberta and the capital efficiency of performing upgrading operations at downstream refineries have recently discouraged the construction of new upgraders in the province. Significant investments have been made in Canadian and US downstream refineries to enable them to accept large volumes of crude bitumen. Some of these investments were done through joint ventures with oil sands producers (e.g. Cenovus Energy and Husky Energy). It should be noted however that the North West Redwater Partnership project by North West Upgrading is moving toward construction with financial assistance from the Government of Alberta.

The high cost of full upgrading is illustrated in Table 1.

**Table 1. Supply Costs for New Oil Sands Projects**

| (CA$/barrel) | **SAGD (Bitumen)** | **Stand Alone Mining (Bitumen)** | **Mining and Upgrading (Upgraded SCO)** |
|---|---|---|---|
| Fixed Capital (initial and sustaining) | 18.92 | 31.14 | 54.72 |
| Operating working capital | 0.45 | 0.70 | 1.06 |
| Fuel (natural gas) | 4.31 | 1.90 | 3.03 |
| Other operating costs (including electricity) | 14.55 | 19.97 | 28.66 |
| Abandonment costs | 0.03 | 0.04 | 0.07 |
| Royalties | 9.43 | 13.61 | 12.39 |
| Income taxes | 3.09 | 4.42 | 7.55 |
| Emissions compliance costs | 0.11 | 0.04 | 0.05 |
| Electricity sales | 0.0 | (0.7) | 0.0 |
| Total supply costs (CA$/b) | 50.9 | 71.1 | 107.5 |
| WTI equivalent (US$/b; after adjusting for blending and transportation) | 85.0 | 105.5 | 109.5 |

Notes:
1. Costs include 10% real rate of return (return on investment of 12.5% and inflation rate of 2.5%)
2. Based on 2013 cost estimates

Source: Oil Sands Economic Outlook, Canadian Energy Research Institute, 2014[1] (Based on Oil Sands Supply Costs and development Projects (2014-2048), Canadian Energy Research Institute, 2014)

According to the Alberta Energy Regulator, the percentage of crude bitumen that is upgraded to SCO is expected to decline from 52% of total crude bitumen in 2013 to 36% in 2023. This is a result of growth in production of bitumen outpacing the growth in upgrading capacity.[2]

## 2.2.Bitumen Transportation

Bitumen that is not upgraded is shipped to markets as diluted bitumen by pipelines (and in recent years by rail in increasing volumes). Dilution is required to enable bitumen to meet pipeline specifications for viscosity and flowability. Condensate and SCO are two main types of diluent used to lower the viscosity and density of bitumen to allow transportation in pipelines (although naphtha, light crude oil, and butanes can also be used). Condensate is lighter than SCO, which means a smaller volume of condensate is required to meet pipeline specifications. On average, a blend of bitumen and condensate will contain 30% condensate, whereas a blend using SCO will contain 50% SCO to meet the same pipeline specifications. If condensate is used as a diluent to transport bitumen to destinations within Alberta, it is usually recycled and re-used at the wellhead. However, if it is used to transport bitumen to markets outside Alberta, it is generally not returned to the province and is used in downstream refinery operations. SCO is not re-cycled. Historically in Alberta, condensate has been preferred diluent agent as compared to SCO.

As oil sands production has increased and as upgrading capacity has failed to keep pace, the volume of diluted bitumen exported from Alberta has increased. Thus, demand for condensate has grown beyond provincial supply and there have been an increasing number of pipeline projects aimed at importing condensate to the province. In the last year, Kinder Morgan reversed the flow of the western portion of the Cochin pipeline system to deliver condensate to Alberta. Further, in the same timeframe, Enbridge expanded the Southern Lights pipeline, which initially began delivering imported diluent from the U.S. to Alberta in 2010.

## 2.3.Market Access Considerations

Environmental opposition to the oil sands industry focused its activities on the approval processes for major oil sands pipeline, particularly Keystone XL and Northern Gateway. As a result, major new pipelines required to support the export out of Alberta of increased oil sands production have not been constructed. It should be noted that rail shipments of oil sands products have significantly increased in the last two years to supplement pipeline capacity. The main outcome has been increased cost of transportation of oil sands products to US markets and the limitation of volumes available for export to Asian markets.

The following quote from the Canadian Energy Research Institute summarizes the situation: "*Given the current existing export pipeline capacity and accounting for the proposed expansions to the Enbridge mainline and assuming a ramp up in rail transport capacity to 700,000 barrels per day by 2017, market access for Western Canadian oil and oil sands volumes will continue to be apportioned until a new pipeline is constructed*." Oil Sands Economic Outlook, Canadian Energy Research Institute, 2014[1] (See Figure 1).

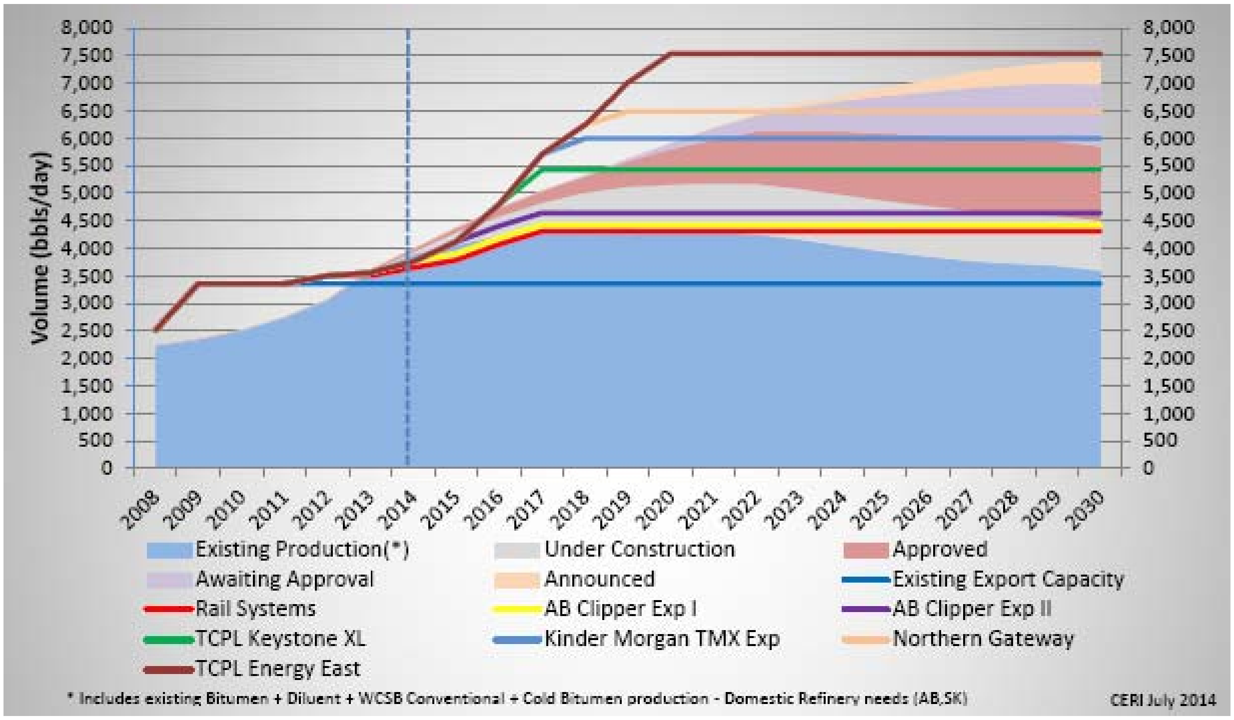


**Figure 1. Oil Sands Production Forecast vs. Pipeline and Rail Transportation**

Source: Oil Sands Economic Outlook, Canadian Energy Research Institute, 2014

## 3. Partial and/or Field Upgrading Opportunity

### 3.1. Current Pathways to Markets for Oil Sands Products

The oil sands industry produces SCO mostly from mining operations. In situ thermal projects mostly produce crude bitumen which must be converted to diluted bitumen for transportation. In 2013, total SCO production was 0.935 million barrels per day with 88% from mining operations and 12% from in situ projects.

Figure 2 provides a conceptual overview of the relationships between bitumen production, upgrading and diluted bitumen transportation. Bitumen recovered at the well site or mining site may be upgraded to SCO which is similar to conventional crude oil and immediately acceptable for pipeline transportation and acceptable to most refineries but optimized for light oil refineries. Bitumen may also be diluted with condensate to produce diluted bitumen (dilbit), or diluted with SCO to produce synbit, to enable transportation by pipelines; however, dilbit and synbit may only be used by heavy oil refineries.

For transportation purposes, SCO has characteristics similar to conventional oil and thus can be shipped to markets by pipeline or rail with limited or no modification. Crude bitumen however behaves as a solid at ambient conditions and therefore must be modified for transportation purposes to ensure that it will freely flow in transportation infrastructure, be it rail or pipeline. The required modification is to reduce the viscosity at ambient temperatures (the extent of dilution will vary depending on seasonal summer and winter conditions). The only way this is achieved currently at industrial scale is by diluting the bitumen with a low viscosity crude oil; the choice of such oil ranges from condensate (very light oil from natural gas processing) to SCO. Therefore, for transportation by pipeline or by rail, crude bitumen is converted to dilbit (bitumen diluted with condensate), to synbit (bitumen diluted with SCO) or to a hybrid of dilbit and synbit.

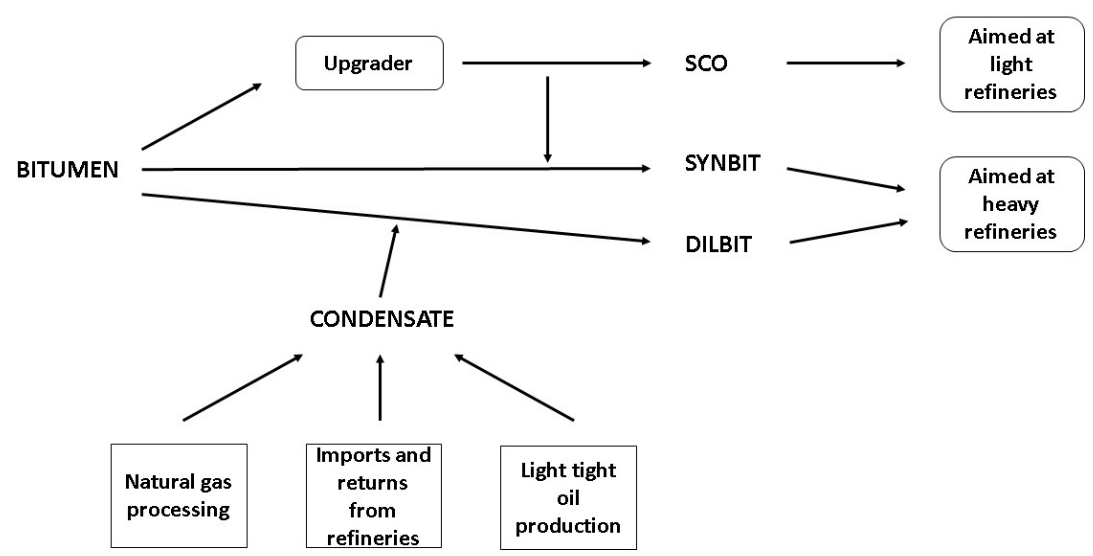


**Figure 2. Conceptual Bitumen Pathways to Market**

## 3.2. Partial Upgrading

Partial upgrading generally refers to the partial use of the technologies used for upgrading bitumen in a manner that achieves less than full upgrading, but at a cost lower than full upgrading. The primary purpose is to reduce the viscosity of bitumen so that it can be shipped with less or no diluent. As such, partial upgrading would produce a heavy oil with properties equivalent to dilbit or synbit. Figure 3 shows how partial upgrading would conceptually fit in bitumen pathways to market. Partial upgrading is not currently practiced on an industrial scale in Alberta.

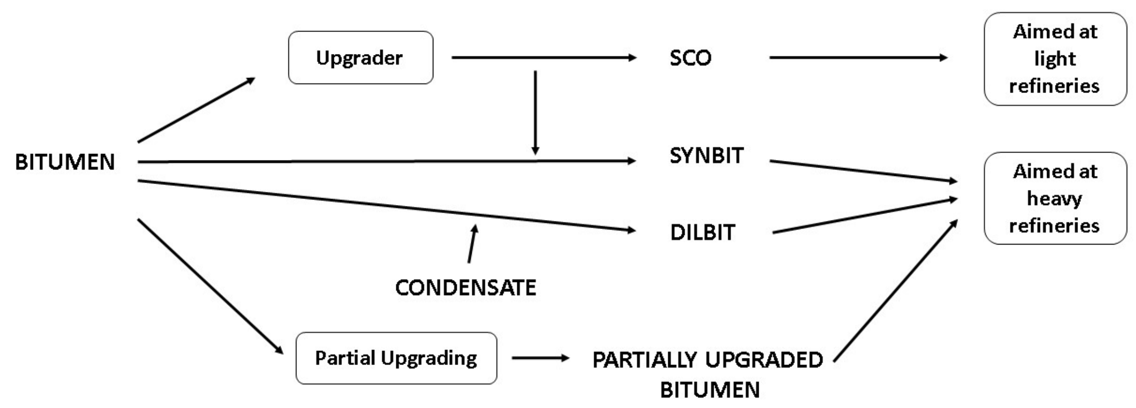


**Figure 3. Partial Upgrading Pathway to Market**

Partial upgrading generally involves the removal or conversion of asphaltenes, along with other heavier organic compounds, to lower the viscosity of the crude bitumen enough so that it flows in pipelines without (or with less) need for diluent. To be commercially viable, partial upgrading must offer significant cost savings over the building of a full upgrader and must produce a crude oil consistent with traditional heavy oils.

## 4. Product Requirements and Costs for Partial Upgrading

### 4.1. Product Requirements

It can be generally considered that there are two options for the deployment of partial upgrading technologies. A basic option is to achieve the minimum upgrading required to meet pipeline specifications at the lowest possible cost. With this option, partial upgrading must cost less than blending diluent into crude bitumen in order to meet pipeline specifications. Another option is to use partial upgrading technology to achieve a product quality higher than dilbit or synbit. With this option, higher product prices must be realized to justify higher costs.

The following cost analysis is focused on the first option of achieving the minimum upgrading required to meet pipeline specifications at the lowest possible cost; this option is preferred by industry and may be analysed as a generic option. The second option of achieving a product with a quality between dilbit/synbit and SCO requires an analysis that accounts for the specifics of the technology under consideration because the product is effectively a niche product; an attempt to address this second option from a generic approach would result in conclusions with considerable uncertainty.

In general, oil sands producers prefer a partial upgrading technology that would provide the basic benefit of meeting pipeline specifications at the lowest possible cost. In this option, the total cost of partial upgrading must not be more than the cost of purchasing and blending condensate or

SCO. Furthermore, to maximize efficiency and enable the lowest possible cost, it is preferred that the partial upgrading operation takes place at the wellhead or bitumen recovery site; this will avoid the cost of producing dilbit that would be required to ship bitumen even over short distances (for example between Fort McMurray and Edmonton). The realized price for partially upgraded bitumen in this basic option will be the same as for dilbit or synbit.

Product specifications that will need to be met are shown in Table 2.

**Table 2. Bitumen Specifications and Characteristics**

| | Bitumen | Dilbit | Partially Upgraded Heavy Oil |
|---|---|---|---|
| API | 6-12 | 19 Min. | Same as dilbit |
| Density (kg/m3) | 0.96-1.02 | 0.904-0.940 | Same as dilbit |
| Viscosity (cSt) | 2.5 million typical | 100-350 | Same as dilbit |
| Olefins (%) | | <1 | Same as dilbit |
| Reid Vapor Pressure (kPa) | | 103 Max | Same as dilbit |
| BS&W (vol %) | | 0.5 Max | Same as dilbit |
| Organic chlorides (wppm) | | 1 Max | Same as dilbit |
| MCR (wt %) | | 8.9 typical | |
| TAN (mgKOH/g) | | 1.9 typical | |
| Nickel (mg/l) | | 39 typical | |
| Vanadium (mg/l) | | 109 typical | |

## 4.2.Cost Analysis

A conceptual cost analysis was conducted using publicly available prices for crude oil and condensate. To provide for a sensitivity analysis that should ensure validity over a range of future market conditions, four scenarios were considered:

- Case 1. Dilbit at current low oil prices (CA$43.98/barrel for heavy oil, March 6, 2015 in Edmonton)
- Case 2. Synbit at current low oil prices (CA$43.98/barrel for heavy oil, March 6, 2015 in Edmonton)
- Case 3. Dilbit at past high oil prices (CA$90.07/barrel for heavy oil, June 30, 2014 in Edmonton)
- Case 4. Synbit at past high oil prices (CA$90.07/barrel for heavy oil, June 30, 2014 in Edmonton)

Oil prices were sourced from First Energy and are shown in Table 3. The results of the cost analysis are shown in Table 4. The key economic parameter for oil companies is the amount of money earned from raw bitumen at the wellsite, in other words: netback. Bitumen is ultimately sold at downstream terminals or refineries, but the costs associated with transportation (including costs for blending to produce dilbit or synbit) must be deducted from the sale price to generate the netback. In Table 4, transportation costs by pipeline or rail are neglected because they would be the same in all scenarios and for the option of partially upgraded bitumen. Prices and cost use information in Canadian dollars, which removes variations associated with exchange rates. Thus, the analysis focuses on the option of achieving pipeline specification by blending versus the use of a partial upgrading technology. Another way to visualize the boundaries of the cost analysis is that it compares a dilbit/synbit blending operation in Fort McMurray to a partial upgrading operation at the same location.

**Table 3. Crude Oil Prices**

| March 6, 2015 | | | June 30, 2014 | | |
|---|---|---|---|---|---|
| **Edmonton (C$/barrel)** | **Price** | **% WTI** | **Edmonton (C$/barrel)** | **Price** | **% WTI** |
| Synthetic Crude | $63.22 | 101.0% | Synthetic Crude | $110.62 | 98.3% |
| Western Canada Select | $43.98 | 70.3% | Western Canada Select | $90.07 | 80.1% |
| Condensate | $63.53 | 101.5% | Condensate | $115.62 | 102.8% |
| **United States (US$/barrel)** | | | **United States (US$/barrel)** | | |
| WTI | $49.61 | | WTI | $105.37 | |
| WTI (C$ @ 79.26) | $62.59 | 100.0% | WTI (C$ @ 93.67) | $112.49 | 100.0% |

Source: http://www.psac.ca/business/firstenergy/ and http://www.firstenergy.com/research/daily-shots/market-and-commodity-prices

In Table 4, netbacks are calculated for the 4 scenarios outlined above and are shown one after the other. It is important to recognize the basis is one barrel of product sold, be it dilbit, synbit or partially upgraded bitumen. In each case, revenue is the market price for heavy oil at the time; the price for heavy oil is that of Western Canada Select in Table 3, which is a widely use price benchmark for Canadian heavy oil. Then, costs are calculated for the blending operation which is simplified to the cost of acquiring the diluent: 30% for condensate at market price and 50% for SCO at market price. Then, cost is subtracted from revenue. Because the basis of the analysis is one barrel of product sold, the fact that less than one barrel of bitumen is used as input must be taken into consideration in the calculation of netback. To obtain netback, revenue less cost is divided by the percent bitumen used as input. For example, in Case1, revenue less costs is divided by the 70% bitumen used as input for blending with 30% condensate: $24.92 / 70% = $35.60. Thus, the oil producer earns a netback of $35.60 per barrel of bitumen.

Finally, the difference between the market price for heavy oil and the netback provides the maximum cost that can be allowed for a partial upgrading option. In partial upgrading, one full barrel of raw bitumen is used as input to yield approximately one barrel of partial upgraded product. The impact of the partial upgrading yield must be included in the maximum allowable cost; for most partial upgrading technologies a cost penalty must be recognized for a yield less than 100% due to the production of coke and off-gases; for some other technologies, it is possible that the yield be more than 100% from the addition of hydrogen or other chemicals.

The analysis of the scenarios in Table 4 shows that allowable total cost for partial upgrading must be less than a range of $8 to $20 per barrel when the price of oil is between US$62 and US$112 per barrel (WTI).

| **Table 4. Bitumen Netback** | | |
|---|---|---|
| **Case 1. Dilbit with 30% Condensate<br>March 6, 2015 in Edmonton** | **Unit Price (C$/barrel)** | **Total (C$/barrel)** |
| **Revenue** | | |
| 100% WCS | $43.98 | $43.98 |
| **Less Costs** | | |
| 30% Condensate | $63.53 | $19.06 |
| Revenue less costs | | $24.92 |
| Netback (C$/barrel of raw bitumen) | | $35.60 |
| Maximum partial upgrading cost (including CAPEX, OPEX, losses to coke and gas, and ROI) | | **$8.38** |
| **Case 2. Synbit with 50% SCO<br>March 6, 2015 in Edmonton** | **Unit Price (C$/barrel)** | **Total (C$/barrel)** |
| **Revenue** | | |
| 100% WCS | $43.98 | $43.98 |
| **Less Costs** | | |
| 50% SCO | $63.22 | $31.61 |
| Revenue less costs | | $12.37 |
| Netback (C$/barrel of raw bitumen) | | $24.74 |
| Maximum partial upgrading cost (including CAPEX, OPEX, losses to coke and gas, and ROI) | | **$19.24** |
| **Case 3. Dilbit with 30% Condensate<br>June 30, 2014 in Edmonton** | **Unit Price (C$/barrel)** | **Total (C$/barrel)** |
| **Revenue** | | |
| 100% WCS | $90.07 | $90.07 |
| **Less Costs** | | |
| 30% Condensate | $115.62 | $34.69 |

| | | |
|---|---|---|
| Revenue less costs | | $55.38 |
| Netback (C$/barrel of raw bitumen) | | $79.12 |
| Maximum partial upgrading cost (including CAPEX, OPEX, losses to coke and gas, and ROI) | | **$10.95** |
| **Case 4. Synbit with 50% SCO June 30, 2014 in Edmonton** | **Unit Price (C$/barrel)** | **Total (C$/barrel)** |
| **Revenue** | | |
| 100% WCS | $90.07 | $90.07 |
| **Less Costs** | | |
| 50% SCO | $110.62 | $55.31 |
| Revenue less costs | | $34.76 |
| Netback (C$/barrel of raw bitumen) | | $69.52 |
| Maximum partial upgrading cost (including CAPEX, OPEX, losses to coke and gas, and ROI) | | **$20.55** |

As discussed earlier, another option for partial upgrading is to use partial upgrading technology to achieve a product quality higher than dilbit or synbit (but less than SCO). Some partial upgrading technologies seek to add value by improving the quality of partially upgraded bitumen beyond viscosity reduction. Examples are:

- Reduced sulphur content
- Reduced acid content
- Reduced residue content.

However, the ability to achieve these benefits will depend on the specifics of the partial upgrading technology. Furthermore, it is not certain that the refinery market will fully value these benefits due to the niche nature of the specific product and the marketing and transportation complexities.

## 5. Other Considerations

Research and technology development in oil sands partial upgrading technologies has taken place for decades in Alberta and Canada. Many technology approaches have been adaptation of the commercial technologies used in full upgrading. Some others have used processes for waste treatment, particularly municipal solid waste, as the starting point. Finally, a few efforts have been based on novel approaches. However, the fact that no partial or field upgrading is currently practiced commercially in the oil sands sector is evidence of the magnitude of the challenges in achieving desired product features and costs limits at the same time.

Many oil sands producers maintain an active interest in this technology area and a few have progressed projects to the stage of scoping and costing a small-scale (approximately 1,000 to 10,000 barrels per day) demonstration pilot projects. Because of the emerging nature of this technology area, many options remain available for size of project, commercial terms (licensing, toll service, etc.), as well as for the preferred process features.

Thus, beyond assessing industry needs with respect to the basic option of eliminating or reducing diluent use, much uncertainty and many possibilities remain for technology embodiment, commercialization approaches and value added options beyond diluent avoidance. However, the basic option of eliminating or reducing diluent use remains the most easily understood and lower risk approach, and therefore the one with the most industry interest.

## 6. References


1 Dinara Millington et al. (2014) Canadian Oil Sands Supply Costs and Development Projects (2014-2048), Canadian Energy Research Institute, online at http://www.ceri.ca/images/stories/2014-07-17_CERI_Study_141_Oil_Sands_Supply_Cost_Update_2014-2048.pdf

2 Alberta Energy Regulator (2014), Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014-2013, Online at http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf