Extracting Economic Value from the Canadian Oil Sands

Upgrading and refining in Alberta (or not)?

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About this report

Purpose. For the first years of Canadian oil sands development, all projects upgraded their heavy crude to light products before pipelining them to market. Today most new oil sands projects are opting to send the heavy crude directly to market—without upgrading or refining it locally. What are the economic drivers shaping the decision to process bitumen or not? What option uses capital most efficiently, and how does the decision to process bitumen locally (or not) affect Alberta and Canada more broadly—for instance impacting jobs, government revenues, and greenhouse gas (GHG) emissions.

Context. This is part of a series of reports from the IHS CERA Canadian Oil Sands Energy Dialogue. The Dialogue convenes stakeholders in the oil sands to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Stakeholders include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

Methodology. This report includes multistakeholder input from a focus group meeting held in Calgary, Alberta, on 7 June 2012 and participant feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis, both independently and in consultation with stakeholders. IHS CERA has full editorial control over this report and is solely responsible for the report's contents (see end of report for a list of participants and the IHS CERA team).

Structure. This report has four sections.

- Part 1: Introduction
- Part 2: The economics for upgrading and refining oil sands
- Part 3: Implications—Production, jobs, government revenues, and GHG emissions
- Part 4: Conclusion

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EXTRACTING ECONOMIC VALUE FROM THE CANADIAN OIL SANDS: UPGRADING AND REFINING IN ALBERTA (OR NOT)?

KEY IMPLICATIONS

In the earlier years of Canadian oil sands development, all projects upgraded their heavy crude to light products before shipping them to market. Today, most new oil sands projects are opting to send the heavy crude directly to market—without upgrading or refining in Alberta. This has spurred a debate about the role of value-added upgrading and refining in the Alberta oil industry. Specifically, the debate is about what role, if any, policy should play in shaping investment decisions about upgrading and refining.

- **Alberta greenfield upgrading economics are challenged by an outlook for a narrow price difference between light and heavy crudes and high construction costs.** Both factors discourage investment in upgrading equipment.

- **Owing to challenging economics, we expect a future with less greenfield upgrading investment in Alberta. Less upgrader construction has benefits, since it reduces the strain on an already tight labor market.** In a case where the region's limited pool of construction workers is deployed on bitumen-producing projects instead of upgraders or refineries, this drives production higher, resulting in more jobs and economic benefits to Alberta and Canada.

- **Instead of building new upgraders or refineries, modifying existing refining capacity to process oil sands is the most economic way to add processing capacity.** When comparing a greenfield project to modifying an existing refinery, modification is more economic. However, refinery conversion projects still face challenging market conditions in North America. With ample supplies of light crude in some regions, refiners have little motivation to undertake costly investments aimed at converting refineries to consume heavy crude.

- **For a greenfield refinery project focused on oil sands processing, the strongest investment return is in Asia, where oil demand is growing. Although the potential is not as strong as in Asia, under the right conditions the economics of new refinery projects in Alberta and British Columbia could work.** Asia's advantage is primarily the result of lower project costs (building a comparable project in China is at least 30% cheaper than in North America). For Alberta and British Columbia—assuming that a new refinery project consumes bitumen, manages to keep capital costs to a minimum, maximizes diesel production, and does not oversupply its market—the economics could work.

—March 2013

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EXTRACTING ECONOMIC VALUE FROM THE CANADIAN OIL SANDS: UPGRADING AND REFINING IN ALBERTA (OR NOT)?

PART 1: INTRODUCTION

To upgrade or not? This is a perennial question facing producers of Canadian oil sands. Bitumen—the raw material produced from oil sands—is an extra-heavy crude oil that needs significant processing to turn into valuable refined products such as diesel and gasoline. Oil sands producers face two options when it comes to the upgrading question. One option is not to upgrade and instead to blend the bitumen with condensate so that it can be shipped via pipeline to refineries with heavy conversion capacity. These are refineries capable of processing extra-heavy crude oil—such as bitumen blended with condensate—into light refined products. The second option is to upgrade the bitumen into a synthetic light crude oil (SCO). SCO can be processed by refineries that lack conversion capacity, which makes it marketable to a broader refining market compared with bitumen blend.

Prior to the onset of the global recession in 2008, the outlook for value-added upgrading and refining in the Canadian oil sands was bullish. Five upgraders were under construction, while six other upgrading projects plus two refining projects were in the earlier stages of development.* A key motivation for upgrading bitumen at that time was that the resulting SCO fetched a much higher price than bitumen blend. Altogether, the projects proposed before the recession represented well over $100 billion in direct capital investment and about 3 million barrels per day (mbd) of upgrading and refining capacity.

Five years later, this outlook has been turned on its head. Only three of the five upgraders under construction in 2008 were completed, and the remaining projects were canceled or put on hold, leaving behind a landscape of partially erected towers. Today, while some projects are advancing, many were canceled.** Most future oil sands supply will be heavy crude that will be sent directly to market—without upgrading or refining locally. What happened to value-added upgrading and refining in Alberta, and what are the implications of oil sands processing for Alberta and Canada?

This report has four parts:

- Part 1: Introduction
- Part 2: The economics for upgrading and refining oil sands

*Refining and upgrading projects and status in 2008: CNRL Horizon phase 1 (construction) plus future phases (approved and announced); OPTI/Nexen Long Lake Phase 1 (construction) plus future phases (approved and application); Suncor Voyageur Phase 1 (construction) plus future phase (approved); Syncrude Mildred Lake debottleneck and expansion (announced); Athabasca Oil Sands Project (AOSP) Scotford 1 Expansion (construction); BA Energy/Value Creation phase 1 (construction) plus future phases (approved); North West Upgrader/refinery (approved); Petro-Canada Fort Hills (approved); Shell Scotford 2 (application); Statoil upgrader (application); Total E&P Northern Lights (application); Peace River Oil BlueSky Refining (announced); Husky Energy- Lloydminster upgrader expansion (announced).
**Projects under construction in 2008 that were completed include CNRL Horizon, OPTI/Nexen, and Albian Oil Sands Scotford 1 Expansion. Projects under construction in 2008 that were canceled or put on hold include Suncor's Voyageur (on hold with a decision expected soon) and BA Energy/Value Creation (canceled). Projects currently advancing include North West Redwater Partnership refinery and Kitimat Clean Refinery.

- Part 3: Implications—Production, jobs, government revenues, and greenhouse gas (GHG) emissions
- Part 4: Conclusion

Throughout this report, we refer to various crude oil terms. See the box "Primer: Crude oil terms" for definitions.

Primer: Crude oil terms

CANADIAN OIL SANDS

In its natural state, raw bitumen is solid at room temperature and cannot be transported in pipelines. For transport, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil—called synthetic crude oil (SCO).

- **Synthetic crude oil.** SCO is produced from bitumen via refinery conversion units called upgraders that turn heavy hydrocarbons into lighter, more valuable components from which gasoline and diesel are manufactured. SCO resembles light, sweet crude oil, with API gravity typically greater than 30°.
- **Bitumen blend and dilbit.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons. A refinery may need modifications to process large amounts of bitumen blends because they result in more heavy oil products than most crude oils. Bitumen blends typically have a gravity of 22°API (similar to other heavy crude oils such as Mexican Maya). The most common bitumen blend involves diluting bitumen with a natural gas condensate to make a substance called dilbit. A typical blend is about 72% bitumen and 28% condensate.

PART 2: THE ECONOMICS FOR UPGRADING AND REFINING OIL SANDS

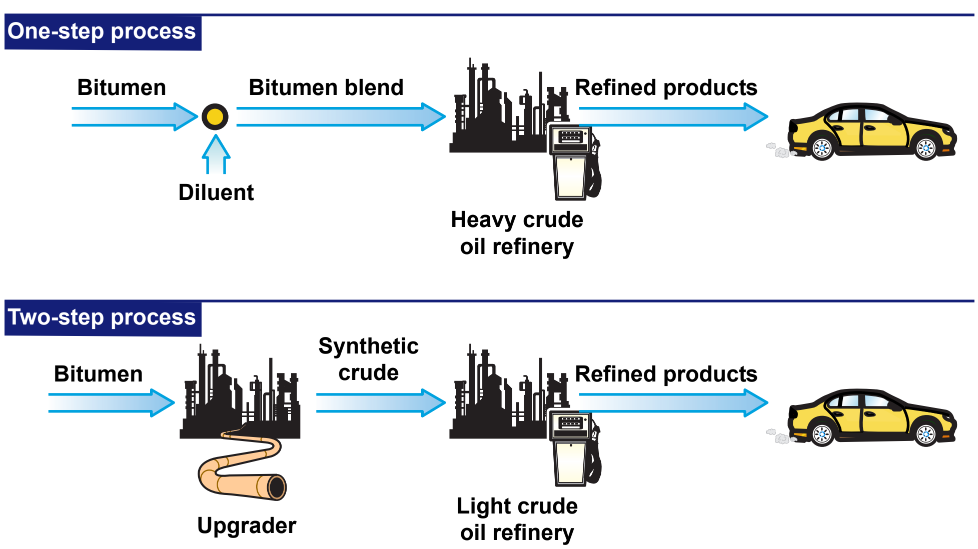
In 2012 Canadian oil sands production was about 1.8 mbd. By 2020 output is expected to reach 3.2 mbd. Today most of the growth is anticipated to be heavy crude supply—shipped by pipeline to be refined outside of Alberta. This section provides upgrading and refining basics and an explanation of why the prospects for value-added upgrading and refining bitumen have dimmed since 2008. Finally, it compares the economics for processing bitumen in Alberta with those of other locations.

ECONOMIC BASICS: UPGRADING AND REFINING OIL SANDS BITUMEN

When first extracted, the bitumen from the oil sands is the consistency of peanut butter. Like other crudes, bitumen must be converted to gasoline or diesel or some other product before it can be consumed. The transformation can take place in a two-step process (upgrading to a light, sweet crude called SCO in one location and refining into transportation fuels in another) or in a single step (refining the bitumen directly into transportation fuels). Prior to the global recession, the two-step process was the dominant strategy deployed in the Canadian oil sands (see Figure 1). Although not the only factor, technical limitations were one reason for the historical dominance of the two-step process.*

Figure 1

Bitumen upgrading and refining: One-step and two-step processes



Source: IHS CERA.
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*In the early years of oil sands development (when commercial production was limited to surface mining operations), extraction methods required bitumen to be upgraded. However, today, new mining extraction techniques have been developed that enable producers to transport blended bitumen, without upgrading. Production by in-situ extraction, a growing source of oil sands supply, also does not require upgrading prior to shipment to market.

Whether a one- or two-step process is deployed, facilities for converting bitumen into lighter products are capital intensive. New greenfield refineries or upgraders cost many billions of dollars. Once built, the facilities make money on the price difference between the heavy crudes they consume and the light products they produce. The wider the price gap, the more money the facilities make and the faster they can pay back the large upfront capital investment. Conversely, if the spread between heavy crudes and light products becomes too small, profit dwindles, and the payback of the initial capital investment is put at risk.

CHANGING TIMES FOR UPGRADING AND REFINING IN ALBERTA

Since the 2009 recession, challenging economics have changed the outlook for upgrading and refining in Alberta. The main causes are project costs and the outlook for the price difference between heavy and light crudes.

Rising capital costs

Cost is a barrier for new upgrading or refining projects in Alberta; when projects were first proposed (in the earlier 2000s), investors expected lower price tags. From 2000 to 2008 (as measured by the IHS CERA Capital Costs Index) costs for building upgraders or refineries in Alberta increased by 70%.* The rate of change was borne out on actual projects built this decade, which had final price tags that were 50% to 100% higher than original estimates. Although costs softened during the recession, they have since recovered and are now higher than pre-recession levels. The situation is not unique to Alberta. Project costs around the globe registered similar escalation owing to increased demand for commodities, equipment, and specialized personnel. However, with absolute costs in Alberta already higher than most other regions, escalation had a more severe impact on project economics in Alberta.**

Narrow light-heavy crude price differentials

The long-term outlook is for a narrow price differential between light and heavy crudes, and this discourages investment in upgrading equipment.

- **Global light-heavy price differentials.** The recession created a sharp drop in oil demand, and this collapsed light-heavy price differentials. Since the recession, the global price difference has remained narrow. One reason is that heavy oil refining capacity has outstripped available heavy feedstock—causing increased competition for these crudes, higher prices, and a shrinking light-heavy price differential. More recently, another cause of narrow differentials is the rapid growth of light, sweet crude supply in North America.*** With light oil oversupplying some North American regions, light

*As measured in Canadian dollars. Source: IHS CERA North American Crude Oil Markets Service, which tracks and provides outlook for capital costs in oil sands projects.

**Capital costs for Alberta oil sands have historically been higher than those for other regions, owing mostly to higher labor costs, lower labor productivity (stemming from extreme weather conditions), and challenges constructing in a remote landlocked location.

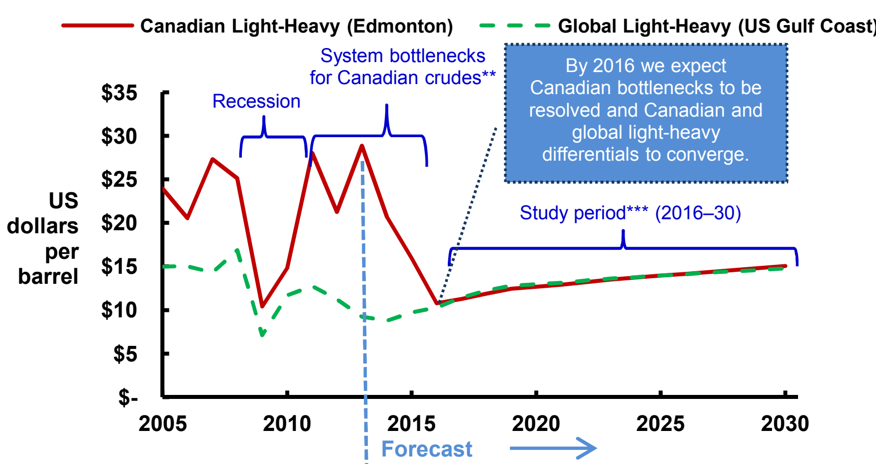
***Since 2011 North American light oil supply has been growing rapidly. The same horizontal hydraulic fracturing technology that unlocked vast reserves of shale gas has been applied to tight oil formations with startling success. Application of this technique is resulting in swift production growth.

crude prices are weak, and this is another factor keeping the price difference between light and heavy crudes narrow.

- **Canadian light-heavy price differentials.** Along with global prices, Canadian light-heavy differentials collapsed during the recession. However, Canadian prices took a different path postrecession. Global light-heavy price differentials remained narrow, while western Canadian differentials widened. The primary cause for the diverging price paths is the rapid growth in North American oil supply. In the past few years both oil sands and tight oil have flooded inland refining markets, with limited outlets to other markets. The flood of oil has resulted in crude price discounts and wide light-heavy price differentials for western Canadian crudes. Although oil supplies are still growing, by 2016 we expect new pipelines will connect rising Canadian supply to new markets. These connections will alleviate the crude oversupply, and Canadian light-heavy price differentials should converge with global ones (see Figure 2).

Critical to our outlook is the assumption that Canadian crudes will have greater access to new markets. Key pipeline projects in our outlook include Flanagan South/Seaway twinning (2014) and Keystone XL (2015–16), both projects connect western Canada to the US Gulf Coast (USGC)—a region with considerable capacity for consuming heavy crude. If either project is delayed, we expect other pipeline projects could be advanced in their place within

Figure 2
Global and Canadian light-heavy price differentials*



Source: Platts, IHS CERA.
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*Canadian light-heavy price differential is the difference between SCO and Cold Lake Blend (a dilbit blend) in Edmonton in constant 2011 dollars. Global light-heavy price differential is the difference between Light Louisana Sweet and Mexican Maya on the USGC in constant 2011 dollars.
**Since 2011 growing supply, pipeline bottlenecks, and refinery disruptions have contributed to price discounts and in temporarily widening the light-heavy differential for oil sands producers. As additional pipeline capacity is brought online over the next few years, these discounts should subside and the differential to narrow by 2016, after which differentials are expected to slowly widen but remain narrower than in the recent past.
***Study range was based on our assessment of the earliest date that a project could be completed and online, given a sanctioning decision today.

the 2014 to 2017 time frame.* In the same way, the alternative projects would ease the wide Canadian light-heavy oil price differentials. If sufficient transport capacity is not built, then prices for Canadian crudes would remain discounted, resulting in wider light-heavy price differentials than would otherwise be the case. However, this situation is not necessarily positive for investment in Alberta. Since the absolute value of all crudes would be depressed (compared with global prices), it may well encourage investment elsewhere.

UPGRADING AND REFINING ECONOMICS: ALBERTA COMPARED WITH ALTERNATIVE REGIONS

Scope and purpose

This analysis is generic and not indicative of any project currently being advanced.

The purpose of our analysis is to create a generic comparison across the range of potential investments for upgrading and refining of oil sands bitumen to help explain the comparative economics of Alberta with alternative regions as well as why plans for upgrading and refining in Alberta have changed.

While a number of oil sands refining and upgrading projects are advancing, the results of our analysis are not intended to reflect the economics of any actual project. The details of specific projects are proprietary and will vary from our generic examples. Further, integrated oils sands operators may evaluate investment decisions as incremental to an existing asset or as an integrated investment (both upstream and downstream).

The scope of our analysis also does not consider the economics for partial upgrading.** Nor does the scope consider petrochemical investments that could be associated with an upgrader or refinery and the corresponding impact of this investment on project economics.

The following is a summary and status report of the oil sands upgrading and refining projects currently being advanced, and how they differ from the generic assumptions used in our analysis:

- **Voyager upgrader.** The greenfield upgrader is a 200,000 barrels per day (bd) facility to be built in Fort McMurray by Suncor and partner Total E&P. The project was under construction (prior to the recession) and was put on hold during the downturn but restarted in 2011. In November 2012 Suncor announced it was reevaluating the economics of the project. Subsequently, in February 2013, Suncor announced a C$1.5 billion write-down on its investment. A final decision on the project is expected in March 2013. The Voyager project differs from our generic model in that it is built in

*Other projects that could provide additional takeaway capacity include the Enbridge Line 9 full reversal (2014), Enbridge Mainline expansion (2015), TransCanada Eastern Mainline oil pipeline project (2017), and the Kinder Morgan Trans Mountain expansion (2017).

**Partial upgrading is not analogous to the upgrading discussed in this report, and technologies and specific products do vary. In general, the goal of partial upgrading is to upgrade the bitumen just enough to transport. While the product is typically higher quality than a typical bitumen blend, its characteristics are closer to a bitumen blend than the light SCO described in this report. Partial upgrading capital costs and product values are different from those described here, and consequently the results of our analysis do not reflect the economics for partial upgrading.

Fort McMurray, it has the potential to be integrated with upstream operations, and—since some expense has already been incurred—the capital costs should be lower.

- **North West Redwater Partnership Refinery.** In November 2012, North West Upgrading and partner Canadian Natural Resources sanctioned the first phase of construction of a greenfield refinery located outside of Edmonton. The first phase is 50,000 bd, and the facility will convert bitumen into refined products. The cost estimate for phase 1 is C$5.7 billion. Differences between the project and our generic model include size, technology (the facility uses gasification), and refined products yields.

- **Kitimat Clean Refinery.** In August 2012, Kitimat Clean announced that it would submit an Environmental Assessment Application to build an oil sands refinery in Kitimat, British Columbia. The plant would convert bitumen into 390,000 bd of refined products destined for Asia export markets.* Compared with our generic model, the capital cost is lower (cost estimate from the early stages of planning is C$13 billion for 390,000 bd of refined products). One reason for the expectation of lower cost is the plan to deploy very large modules fabricated in Asia for the construction. Other differences from our generic mode include yields of refined products, size, and location (ours does not prescribe to a particular location along the west coast).

Project types and markets included

Since the upgrading or refining of bitumen can be performed in a variety of geographical locations (in Alberta, in the market the fuel is consumed, or somewhere along the way), our economic evaluation considered a range of project types and market locations (see Table 1).

Table 1

Project types and markets included in IHS CERA analysis

Project Types	Markets
Greenfield upgrader	British Columbia (West Coast)
	Alberta (Edmonton)
Refinery conversion	Alberta (Edmonton)
	Quebec (Montreal)
	US Midwest (Chicago)
	US Gulf Coast (Coast)
	Asia (South China)
Greenfield refinery	British Columbia (West Coast)
	Asia (South China)
	Alberta (Edmonton)

Source: IHS CERA.

*The diluents needed to transport the bitumen would be recycled back to Alberta by a pipeline.

Market locations

Although oil sands markets are geographically limited today, we anticipate that markets will expand.* Therefore, we have compared the economics in Alberta to those of existing and future markets:

- Existing markets: Alberta, the US Midwest
- Existing market, with large potential for future growth: the US Gulf Coast
- Future markets: eastern Canada and Asia (including export-orientated facilities along Canada's west coast)

For a more detailed explanation of future markets for oil sands, please see the IHS CERA Special Report *Future Markets for Oil Sands.*

Project types

We include three project types in our economic evaluation.

- **Greenfield upgrader.** Greenfield oil sands upgraders could be built in the Edmonton area (a region of almost 1.2 million people) of Alberta, close to where oil sands are extracted while providing access to export pipelines and local refineries.** Potential also exists to upgrade or refine bitumen "along the way" to the end consumer. For example, bitumen could be converted to SCO on Canada's West Coast before being exported to refineries in Asia or elsewhere. Fort McMurray was not included because only integrated upgraders (upgrader built in conjunction with a mine or in-situ project) have been built or proposed there.
- **Refinery conversion.** Modifying an existing refinery to convert capacity to process heavier crudes, like bitumen, is much cheaper than building a new one. Existing refineries in eastern Canada, US Midwest, US Gulf Coast, and Asia are all candidates for conversion projects. And although there are limited refineries to convert in Alberta, we have included this case in our analysis.
- **Greenfield refinery.** North America's demand for refined products is flat to declining, providing fewer opportunities for greenfield refineries. Even so, because demand for some refined products—specifically diesel—is growing, we have included an Alberta refinery in our results. In contrast to North America, developing countries—including China—are increasing their demand for all refined products. Although we anticipate that Asian refineries will supply most of the region's refined products, some volumes could be imported. Consequently, our analysis includes both an Asian greenfield refinery and a greenfield refinery on Canada's west coast targeting exports to Asia.

*Most oil sands crude oil is consumed in western Canada and the US Midwest. Although limited quantities of oil sands reach every refining region in North America (US West Coast, US Gulf Coast, US Rockies, US East Coast, and central and eastern Canada), pipeline infrastructure is currently a limiting factor for greater movements of oil sands to other markets.
**Source: Statistics Canada (2012), 2011 Census.

Economic inputs

Although many factors have an impact on upgrading or refining finances, a few key variables dominate the economic return: the upfront capital costs, the price difference between light and heavy crudes (called the light-heavy price differential in our analysis), and the operating costs. To compare the economics among the project types and markets in our analysis, we identified probable values for each key variable (see Table 2 for a summary of inputs):

Capital costs

These are all the expenses for constructing a facility, including the cost of equipment, machinery, steel, instrumentation, engineering, design, and construction labor. Since the scope of projects can vary considerably, we assumed a project cost range—high and low. Differences in project cost arise mostly from three factors:

- **Project scope.** The project scope can vary considerably among projects—even projects of the same type. In the case of refinery conversion projects, some refineries on the US Gulf Coast require little to no capital investment to increase their consumption of bitumen blends since they are already able to process heavy crudes.* Conversely, existing refineries in most other regions are configured to consume lighter crudes (light, sweet and light, sour). These less complex refineries require more extensive modifications before they can process meaningful quantities of bitumen. Even among greenfield refinery projects the scope can vary. For example, projects that produce more diesel (instead of gasoline, or other heavy products) require more costly equipment. For our analysis we assumed conversion projects resulted in traditional refinery product yields (about twice as much gasoline as diesel). For greenfield refineries we ran two assumptions. One case assumed traditional refinery product yields (two times more gasoline than diesel); the other assumed the refinery was configured to maximize diesel production, resulting in equal amounts of gasoline and diesel. Since diesel is a higher-value product, refineries that maximize diesel production generate higher returns.

- **Construction techniques.** Owing to differing construction methods, inland locations are more expensive to build. With ocean access, larger components or modules of the facility can be built off site. Once complete, the modules can be transported to site and assembled like building blocks. This technique materially reduces the labor requirements and—consequently—the cost. Access to the ocean is critical, because modules can be the size of a football field and need to be transported by ship. Although inland locations can use this method, since the modules must be transported by truck, this materially reduces the module size and corresponding cost savings.

- **Labor costs.** Construction labor is a large factor in why costs vary among regions. In North America direct labor typically makes up 30% of a project's total cost, and labor costs in Alberta are higher than those of other regions. One cause is the limited

*The US Gulf Coast region is home to 30% of the world's coking capacity already, and the region currently processes approximately 2.4 mbd of heavy crude—similar to the bitumen blends from the Canadian oil sands. Since many refiners are already well suited to process heavy crudes, it is conceivable that no investment (zero capital cost) may be require to consume bitumen blends. For our analysis we ran both our high and low cases with the same capital cost of $14,000 per flowing barrel (see Table 2).

Table 2

Key asssumptions for economic calculations

Project Type	Location	Capital cost (US$ per 100,000 bd of capacity)	Operating cost (US$ per barrel)	Light-heavy differential[1] (average from 2016 to 2030, US$ per barrel)	Light crude input	Heavy crude input	Refined product yields (volume ratio of crude feed: gasoline: diesel)[2]
Greenfield refineries	Alberta (Edmonton)	$7.2–8.6 billion	$8.00–10.00	$13.90–25.35[3]	Edmonton Par (in Edmonton)	Dilbit to bitumen (in Edmonton)	2:1:1 to 3:2:1
	West Coast	$5–6 billion	$7.00–9.00	$14.22–24.51[3]	Arabian Light (on West Coast)[4]	Dilbit to bitumen (on West Coast)	2:1:1 to 3:2:1
	Asia (South China)	$2.8–3.5 billion	$4.50–6.50	$12.16–14.66[3]	Arabian Light (in South China)	Dilbit (in South China)	2:1:1 to 3:2:1
Refinery conversions	Alberta (Edmonton)	$2.8–4 billion	$6.00–8.00	$13.90	Edmonton Par (in Edmonton)	Dilbit (in Edmonton)	3:2:1
	Quebec (Montreal)	$1.9–2.8 billion	$5.00–7.00	$13.90	Edmonton Par (in Montreal)[5]	Dilbit (in Montreal)	3:2:1
	US Midwest	$1.7–2.6 billion	$5.00–7.00	$16.19	WTI (Chicago)	Dilbit (in Chicago)	3:2:1
	US Gulf Coast	$0–1.4 billion[6]	$4.50–6.50	$13.77–16.27	LLS (St. James)	Dilbit (on US Gulf Coast)	3:2:1
	Asia (South China)	$1.2–2 billion	$4.00–6.00	$12.16–14.66	Arabian Light (in South China)	Dilbit (in South China)	3:2:1
Upgraders	Alberta (Edmonton)	$6–7 billion	$8.00–10.00	$29.03	SCO (in Edmonton)	Bitumen (in Edmonton)	n/a
	West Coast	$4.2–4.9 billion	$7.00–9.00	$28.01	SCO (on West Coast)	Bitumen (on West Coast)	n/a

Source: Various sources, IHS CERA, 2013.

1. Light-heavy differential based on average price from 2016 to 2030 of the most prevalent light crude oil in each market and of dilbit or bitumen (depending on the project) delivered to each market. The price range was chosen to start in 2016 as it was deemed the earliest that a facility could be operational given a sanctioning decision today. Alberta-based oil sands crude prices were adjusted to reflect expected pipeline and tanker tolls—assuming the lowest-cost transportation options. Toll assumptions from Edmonton to each market are $4 to the West Coast; $6 to $8.50 to Asia; $4.50 to the US Midwest (Chicago area); $8 to $10.50 to the USGC; and $6 to Montreal. The tolls to both the USGC and Asia are less certain; therefore, a high and low transportation assumption resulted in a range for the light-heavy differential.
2. Refined product yield assumptions varied for greenfield refineries. The low case assumes that the refineries targets more gasoline, while the high case targets more diesel. For conversions, the refined product yields were assumed to target gasoline. With the exception of West Coast Refinery (where we assumed the products would be sold to the Asian market), we assumed that refined products would target the local market.
3. The wide differential is based on consuming bitumen; the narrow differential is based on consuming dilbit.
4. Arabian Light was chosen as representative of light sweet crude oil on the West Coast to reflect global crude access and orientation of facility as an export facility targeting Asia.
5. For Montreal, an inland crude (Edmonton Par) was chosen to reflect anticipated access to inland crudes which would come with pipeline access to inland markets.
6. Approximately 2.4 mbd of capacity on the USGC is already suited to consuming heavy oil sands crude oil, and no capital investment may be required.

regional pool of construction workers (demand from oil sands projects often exceeds local supply, requiring workers to be recruited from across Canada and the globe). Another is Alberta's landlocked location, keeping on-site labor requirements relatively high (see construction techniques). Climate is also a concern; cold weather decreases worker productivity.

Light-heavy price differential

Depending on the project type, the crudes used for the light-heavy price differential vary.

- **Greenfield refineries and refinery conversions.** When considering a heavy crude oil refinery investment, whether it's a greenfield facility or a conversion project, refiners compare the profit for consuming light crude to the profit from gearing up to take heavy crude. Heavy crudes are more expensive to process (it takes more energy and requires expensive equipment). In the end, the price discount for heavy crude must sufficiently cover the cost of the additional equipment and energy. For refinery conversion cases the light-heavy price differential is based on the difference in the price for the light crude and bitumen blend (for this report we assumed this to be dilbit).* For North American greenfield refinery cases, we assumed two potential scenarios—one where bitumen blend (dilbit) was converted to refined products and another where bitumen only was converted to refined products (assuming that the diluents used to transport the bitumen would be recycled back to Alberta for a fee).** In the later case the price difference between the light crude in the region and bitumen were compared.

- **Greenfield upgrader.** Since the input to an upgrader is bitumen and the output is SCO, our light-heavy price differential is based on the price difference between SCO and bitumen. Even when we considered the economics for an upgrader outside of Alberta, we used SCO and bitumen (again, assuming that the diluents were recycled back to Alberta for a fee).

Built into our Table 2 outlooks for light-heavy price differential is the assumption that new pipelines are constructed and western Canadian crudes have sufficient access to heavy crude markets from 2016 to 2030. Consequently, light-heavy price differentials reflect global market pricing and (compared with today) are relatively narrow.

Operating costs

As the name suggests, these are the day-to-day costs for the parts, maintenance, materials, labor, and energy required to run the facility. As with capital costs, the higher the operating costs, the more challenging the economics.

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*The light crude oil chosen for each market was based on the expectation of the most prevalent light crude oil in the region where the facility is located when it is operating. For markets where the light crude oil or bitumen blend are not currently marketed, our best estimate of future transport costs was used.

**The cost associated with diluent return was included as part of the bitumen price.

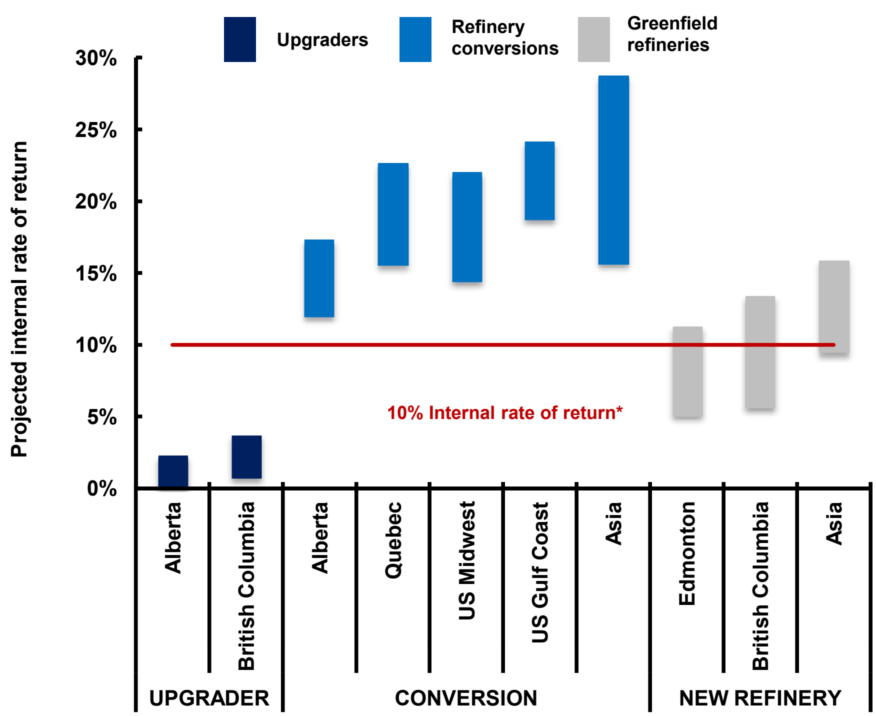
The results

To compare the economics for processing bitumen in Alberta to that of other locations, we compared the internal rate of return (IRR) across all project types and markets (see Figure 3).* In reality, the IRR that is acceptable to secure an investment depends on the amount of debt versus equity funding for a project. The threshold IRR is unique for every company and project. Although we have highlighted a 10% IRR rate as an indicative threshold in Figure 3, this is not necessarily the cutoff for all projects. Actual thresholds could be higher or lower than this indicative value.

Refinery conversions

As a group, refinery conversions provide the highest potential returns for processing heavy oil sands because the capital investment is significantly lower than that for a greenfield project. For the US Gulf Coast, we assumed a capital cost for converting to process heavy crude. However, numerous refineries in the Gulf region are already fitted to consume heavy oil and do not require conversions. And while North American conversion economics look strong, tight oil is a hurdle for these projects. Growing availability of light quality tight oil provides refiners little incentive for undertaking costly projects geared at increasing consumption of heavy crudes.

Figure 3
Internal rate of return for oil sands upgrading and refining projects



Source: IHS CERA.

*IRR is a way to measure the economics across all investments in a comparable manner and is a typical metric for comparing the economics among alternative projects. The IRR calculates the rate of return so that the net present value (NPV) of all future capital expenditures and revenues is zero.

Greenfield refinery

The strongest greenfield refinery investment returns are in Asia, where oil demand is growing. The difference between North America and Asia is primarily the result of Asia's lower project costs (see the box "Why are construction costs in China lower?"). Considering that Asia needs to build new refineries regardless (to keep pace with growing demand for refined products), the economics for heavy oil conversions are likely more reflective of the actual investment decision to process heavy oil. Consequently, if oil sands could access Asia in meaningful quantities, investment in greenfield refineries processing dilbit could be economic.

Although downside risk exists, given the right conditions, the economics of greenfield heavy oil refineries in Alberta and British Columbia could work. The ranges of potential returns in our results are driven mostly by the difference of project types considered. The weakest returns represent a refinery consuming dilbit and producing traditional product yields (more gasoline than diesel). The highest return reflects a refinery consuming bitumen and producing equal volumes of diesel and gasoline. While the actual greenfield refinery projects being advanced in Alberta (i.e., North West Redwater Partnership) and British Columbia (i.e., Clean Kitimat) are not direct comparisons with these generic examples, they are the most similar to the high IRR results.

There are downside risks to the Alberta and British Columbia greenfield refinery cases. For the Alberta refinery we assumed that the refined products were sold in the local market and did not oversupply it. If too much refinery capacity is built, refined products could flood the market and weaken product prices, challenging new refinery economics. For the British Columbia greenfield refinery case, we assume the refined products are transported to Asia and receive competitive prices. If transportation costs are higher than we assumed or if buyers require discounts, project economics would weaken.*

Upgrading

Although the economics for greenfield upgrading are challenging, returns for upgrading on the West Coast are a bit stronger than in Alberta. Key factors are lower capital costs and higher prices for light crude on the west coast compared with Alberta.**

So, how do the economics for upgrading in Alberta compare with pre-recession economics? When we rerun our Alberta upgrading economics, considering 30% lower capital costs and a light-heavy spread that reflects the thinking prior to the recession, the IRR of an Alberta upgrader ranges between 10% and 13%—considerably higher than our current outlook and above our indicative economic threshold for new investments.

Proponents of upgrading in Alberta have suggested that the government should boost the economics by creating incentives to upgrade. But what would it take to improve upgrading

*Marine shipping costs can vary for a number of reasons: density of product, vessel size, distance, and global demand for tankers. In this report refined product transport costs from the west cost to Asia averaged from US$1.20 to US$2.00 per barrel depending on the product (2016 to 2030 average). This assumed using Aframax vessels transiting one way (no return) to South China.

**The outlook for west coast oil price is comparatively higher owing to the oversupply of light crudes in inland North America, which (even considering new pipeline connections) is expected to depress Alberta prices compared with costal ones—potentially in the range of US$2 to US$3 per barrel.

economics? Although there are a number of potential incentives to be considered; the cost of capital and the price of bitumen are two key levers:

- **Cost of capital.** The government could provide loan guarantees to third parties or launch its own upgrading enterprise. Both would reduce the cost of capital and, consequently, the IRR required for an investment to proceed. However, by doing this, the government takes on financial risk.

- **Price of bitumen.** The Alberta government has the option to receive royalties in the form of bitumen barrels instead of cash. The government could sell the royalty barrels at a discounted price to an upgrader. This would widen the light-heavy price difference and strengthen upgrading economics. However, this is a costly proposition. For the Alberta upgrader to boost the IRR to 8%, the bitumen price must be discounted by between US$10 and US$15 dollars per barrel. For a 100,000 bd facility, this subsidy would cost in the range of a half billion dollars a year.

Why are construction costs in China lower?

The primary advantage over North America of building a refinery in China is low capital costs. Cost of labor is the key reason for the gap. Labor cost for a North American refinery project typically constitutes about 30% of the project's total cost; for China, it makes up about 10%. China's low labor rates factor into additional discounts for labor-intense manufactured goods—such as process equipment and fabricated steel products.

Projects built in China by joint ventures (JVs) with Western companies tend to cost more than projects built solely by Chinese companies. Typically, the cost of a Chinese-led project is lower because the Chinese companies generally pay lower wages, rely almost exclusively on Chinese engineering and construction contractors, and offer more scope and independence to these firms. JVs focus more on meeting Western quality standards and use more expensive international engineering resources, leading to higher overall costs. In our analysis we assumed costs that are reflective of a project built by a Chinese firm.

PART 3: IMPLICATIONS—PRODUCTION, JOBS, GOVERNMENT REVENUES, AND GREENHOUSE GAS EMISSIONS

The conventional wisdom is that by pipelining bitumen, Alberta is exporting the jobs and economic benefits from upgrading or refining. This section challenges that thinking. Construction of bitumen processing facilities in Alberta places additional strain on a tight job market, increasing already high costs for oil sands development and further challenging investment. Alternatively, in a case where the region's limited pool of construction workers are deployed on bitumen-producing projects (instead of processing facilities), this drives production higher, creating more jobs and benefits to Alberta and Canada than construction of upgrading or refining facilities. It also reduces the GHG intensity of oil sands production.

THE ALBERTA LABOR LIMIT

Alberta has a relatively small skilled trade workforce for constructing industrial projects—in our estimate about 17,000 workers are available for construction projects (welders, pipefitters, electricians, and other skilled trades) in Alberta. These workers support oil sands activity plus other industrial projects in the province, such as electrical generation, pipeline construction, infrastructure, and maintenance.

Often Alberta labor demand exceeds supply. Staffing industrial turnaround work (large maintenance projects that are periodically executed over a one- to three-month period in the spring and fall) is a perennial problem. To staff turnarounds, multiple projects demand thousands of skilled trade workers at the same time. During the turnaround seasons, workers from the rest of Canada are regularly called on. There were longer-term labor shortages in 2007 and 2008 when the demand for construction labor exhausted both Alberta and Canadian supply. Foreign workers were recruited to fill the gap. Now, once again, the Alberta labor market is constrained. Foreign workers are already at work on oil sands and other projects in the province, and their numbers are projected to ramp up over the next few years.

During the 2007 and 2008 labor shortage, projects faced expensive implications. Wage rates were one factor, increasing by 5.9% annually.* In addition total labor costs were boosted by overtime pay (over a 40-hour week, wages are paid at time-and-a-half and double rates), signing bonuses, employee recruitment costs, and living allowances. Worker productivity also took a hit: as the labor shortage grew, the average skill level of the workforce declined. But perhaps the most costly implication of the shortage was the expensive start-up and operational issues that numerous projects faced.

Since 2008, IHS CERA has been tracking and projecting industrial construction labor demand in the province as well as estimating available supply from Alberta and the rest of Canada.** Considering the IHS CERA outlook for supply and demand of Alberta construction workers, to avoid the need for foreign workers and the costly implications of a labor shortage, the province should keep total construction labor demand at around 25,000 workers. At this level, workers from other parts of Canada are still required to support projects, although

*Alberta building trade rates from third quarter 2006 to second quarter 2009.
**Labor data are available within our North American Crude Oil Market Service, www.ihs.com/products/cera/energy-forecasting/canadian-oil-sands.aspx.

no more than what has historically been recruited. Since the demand from other Alberta industrial projects averages near 8,000 workers, this means that oil sands demand would need to stay near 17,000 workers.

Critical to our assumption that labor remains a long-term constraint to growth are the expectations that oil sands growth remains strong and that government policy for accessing foreign labor does not change significantly from today (i.e., existing barriers for accessing and keeping foreign labor in the province continue).*

Comparing two future scenarios for oil sands growth

In a scenario under which oil sands growth continues to be strong and construction labor continues to be the most critical constraint for growth, the province creates more jobs and economic benefits by not upgrading bitumen. To illustrate this, we compared the outcomes of two future scenarios to 2020: one where all new supply is from bitumen—referred to as bitumen only; and another where the amount of bitumen upgraded in the province stays about static with today—referred to as 60% upgrading. In both future scenarios we assume that Alberta is limited to 17,000 workers for new oil sands construction.** Even though this comparison is theoretical, it enables a quantification of the affects of upgrading (or not) on production growth, jobs, government revenue, and GHG emissions.

Although refining or other spin-off investments (such as petrochemical projects) were not included in the analysis, the jobs and economic benefits are not dissimilar to those from upgraders. Consequently, under an assumption that part or all of the upgrading capacity was substituted with refining or petrochemical capacity, the direction of the results would be similar.

Production

Upgraders improve the quality of oil sands crude oil, but they do not add production. In a bitumen-only scenario, since all construction workers are deployed in bitumen-yielding mining or in situ projects, this results in almost 1 mbd more production by 2020 than the 60% upgrading scenario.

- **Bitumen-only scenario.** 2020 oil sands production (SCO and bitumen): 3.4 mbd
- **60% upgrading scenario.** 2020 oil sands production (SCO and bitumen): 2.5 mbd

Direct long-term jobs

Long-term jobs from oil sands facilities include roles in project operation, supervision, administration, maintenance, and engineering, as well as periodic maintenance work. For

*In June 2012 the Canadian government changed the process for accessing foreign labor by introducing a accelerated labor market opinion process. The new process shortened the timeline, but it still takes a company 6 to 12 months to bring a new foreign worker to Canada. Other barriers include limits to the cumulative time that workers can stay in Canada and difficulty in immigrating.

**Other key assumptions include New production is assumed to be 80% of productive capacity additions. Growth is 45% from mining and 55% from in-situ projects. Interest rate for NPV calculations is 10% and the tax rate 29%. Values for crude for this analysis are consistent with those reported in part 2.

mines and in-situ projects, there are additional jobs for sustaining production levels (such as extending mine trains or drilling additional wells for in situ). For projects of comparable size, in-situ projects and mines provide more long-term jobs than upgraders. Consequently, when construction workers are deployed to build upgraders (resulting in fewer mining or in-situ projects being built), the number of long-term jobs in the province is actually lower.

- **Bitumen-only scenario.** New long-term direct jobs from now to 2020: 12,500
- **60% upgrading scenario.** New long-term direct jobs from now to 2020: 8,500

Government royalties

A royalty is the price Alberta charges a producer for the resource it extracts—bitumen in this case. Consequently, upgrading bitumen does not generate additional royalties for the province. Since the bitumen-only scenario results in almost 1 mbd more production, it also provides more royalties.

- **Bitumen-only scenario.** NPV of royalties for new facilities brought on between now and 2020 over 40 years: C$29 billion (annual average of C$5.5 billion per year)*
- **60% upgrading scenario.** NPV of royalties for new facilities brought on between now and 2020 over 40 years: C$15 billion (annual average of C$2.7 billion per year)*

Income taxes

As shown in part 2, Alberta upgraders struggle to generate positive cash flow and consequently pay minimal income tax. Since in situ and mining projects generate positive returns, the bitumen-only scenario (with higher production and cash-flows) results in more income tax revenue.

- **Bitumen-only scenario.** NPV of taxes for new facilities brought on between now and 2020 over 40 years: C$18 billion*
- **60% upgrading scenario**. NPV of taxes for new facilities brought on between now and 2020 over 40 years: C$7 billion*

GHG emissions

Along with production growth, aggregate emissions from oil sands are projected to grow. The GHG emissions for extracting a barrel of bitumen vary between 29 and 89 kilograms of carbon dioxide equivalent ($kgCO_2e$) per barrel; upgrading adds another 51 $kgCO_2e$ per barrel.** Considering the emissions produced in Alberta only, the bitumen-only scenario reduces the GHG intensity (because it avoids the extra GHG emissions from upgrading). However, when aggregate emissions from the oil sands are considered, the bitumen-only

*All NPV calculations assume 10% interest.
**The lower range is for mining bitumen, and the higher range is for producing bitumen from the cyclic steam stimulation method. Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*

Table 3

2020 GHG emissions compared: Bitumen-only and 60% upgrading scenarios[1]

	Alberta GHG emissions (extraction and upgrading)		All GHG emissions (extracting through to refining)	
	Bitumen-only	60% upgrading	Bitumen-only	60% upgrading
2020 aggregate GHG emissions from oil sands sector ($mtCO_2e$ per year)	90	82	174	140
2020 average GHG intensity of production ($kgCO_2e$ per barrel)	72	89	139	153

Source: November 2012, IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*
1. This analysis assumes no significant improvement in GHG intensity from 2012 to 2020 and does not factor in the impact of carbon capture and storage. The bitumen-only case considers the GHG emission for transporting diluents to the refinery and back to Alberta.

scenario (with higher overall production) results in higher total GHG emissions—8 megatons of CO_2e per year higher than the 60% upgrading scenario (see Table 3).

Expanding the boundary beyond Alberta (including GHG emissions from crude transportation and refining outside of the province) changes the magnitude but not the direction of the findings. Considering all emissions from oil sands extraction to refining (including upgrading and crude transport), the GHG intensity of the bitumen-only scenario is still lower than the 60% upgrading scenario.* The bitumen-only scenario still has higher aggregate emissions (stemming from the higher overall production).

Although the aggregate GHG emissions from oil sands in the two scenarios are significant, it is important to keep the total emissions in perspective. By 2020 the aggregate emissions from oil sands are less than 0.5% of global emissions** Further, in the absence of oil sands development, the majority of the emissions in Table 3 would still be generated. Without growth in oil sands, world oil demand would be unchanged. Consequently, oil sands supply would be substituted by other crude oils, which also generate GHG emissions.***

*On an intensity basis, although refining bitumen is more GHG-intensive than refining SCO, the combined emissions from the two-step process (upgrading bitumen and then refining) is still higher (resulting in 97 $kgCO_2e$ per barrel, compared with 62 $kgCO_2e$ per barrel for refining bitumen directly). Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*
**Using IHS Global Scenario projections, 2020 GHG emission range from 32,000 to 37,000 $mtCO_2e$ per year.
***When GHG emissions are viewed on a well-to-wheels basis—considering all emissions from producing oil through to combusting the fuel in a vehicle engine—oil sands are 4% to 18% higher than the average crude and within the same range as some other sources of oil that could replace oil sands supply. Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*

PART 4: CONCLUSIONS

Prior to the onset of the global recession, the industry was set to upgrade and refine bitumen in the province. Oil sands companies were gearing up to spend more than US$100 billion on oil sands processing facilities in Alberta. Five years later, many projects have been canceled or delayed.*

The cancellations reflect the reality that, in many cases, value-added upgrading and refining in Alberta does not equate with adding profit. However, there are exceptions. Although the return is not as high as in Asia, given the right conditions the economics of new refinery projects in either British Colombia or Alberta could work (assuming that the refinery can consume bitumen, maximize diesel production, control capital costs to a minimum, and maintain a strong price for its products by not oversupplying the market). A key risk with any new refinery investment in North America is the flat to declining demand for refined products in the continent. Consequently, any sizable new refining facility must export its product overseas, likely to Asia, where it would need to compete with refiners there.

Another factor challenging North American upgrading and refinery conversion investments is the emergence of tight oil. Tight oil provides growing supplies of light crude, similar to upgraded oil sands (SCO). With growing supplies of light crude, the continental price difference between light and heavy crudes is expected to remain narrow. Tight oil is also reducing incentives for investing in heavy oil conversion projects, since refiners have plenty of light crude to process.

At this juncture, in many cases investors fail to get a reasonable return on the billions they must commit for a bitumen processing facility. However, this may not be all bad for Alberta. Considering the region's constrained labor market, less investment in processing facilities will enable faster growth in oil production, which also provides jobs and revenue to the province. Further, by deploying resources to build bitumen production now, the province is not closing the door to bitumen processing in the future. If the future unfolds differently than we assume and the economics for value-added investments strengthen, the option will always remain to upgrade and refine then.

*Refining and upgrading projects that are considered canceled or delayed include OPTI/Nexen future phases, Syncrude Mildred Lake debottleneck and expansion, BA Energy/Value Creation, Albian Sands Scotford 2, Statoil Upgrader, Total E&P Northern Lights, Peace River Oil BlueSky Refining, Husky Energy, and the Lloydminster upgrader expansion.

REPORT PARTICIPANTS AND REVIEWERS

On 7 June 2012, IHS CERA hosted a focus group meeting in Calgary, Alberta, providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to upgrading and refining in Alberta. Additionally, a number of participants reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report, for which IHS CERA is exclusively responsible.

Alberta Department of Energy

Alberta's Industrial Heartland Association

Alberta Innovates, Energy and Environmental Solutions

Alberta School of Business (University of Alberta)

American Petroleum Institute (API)

Canadian Association of Petroleum Producers (CAPP)

Canadian Building Trades (Building and Construction Trades Department, AFL-CIO, Canadian Office)

Canadian Oil Sands Limited

Cenovus Energy Inc.

Devon Energy Corporation

Conoco Philips Company

Chevron Canada Resources

Canadian Natural Resources Ltd.

IBM Canada

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

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We also recognize the contribution of Carmen Velasquez, IHS CERA Associate Director, to this report.