In-Provence Upgrading Economics of a Greenfield Oil Sands Refinery

By Salman Nissan and Ed Osterwald

07 April 2014
# Table of contents

1. **EXECUTIVE SUMMARY** ........................................................................................................... 1  
   1.1. **INTRODUCTION** .................................................................................................................. 1  
   1.2. **ALBERTA OIL SANDS** ......................................................................................................... 1  
   1.3. **APPROACH** .......................................................................................................................... 2  
   1.4. **TECHNICAL REVIEW** .......................................................................................................... 3  
   1.5. **SUPPLY / DEMAND AND PRICING** .................................................................................... 4  
   1.6. **ECONOMICS OF IN-PROVINCE UPGRADING OF OIL SANDS** ..................................... 6  
   1.7. **CONCLUSIONS** .................................................................................................................... 8  

2. **DEVELOPMENT OF OIL SANDS IN ALBERTA** ................................................................. 10  
   2.1. **INTRODUCTION** ................................................................................................................ 10  
   2.2. **OIL SANDS DEVELOPMENT** .................................................................................................. 11  
      2.2.1. In-situ oil sands developments ............................................................................................. 11  
      2.2.2. Government of Alberta Policy on Upgrading Bitumen ......................................................... 11  
   2.3. **BACKGROUND TO UPGRADING** .......................................................................................... 12  
      2.3.1. Upgraders, the Great Recession, and Foreign Direct Investment ........................................ 13  
      2.3.2. If In-Province Upgrading Were Profitable, Why Isn’t Industry Doing It? ......................... 14  
   2.4. **IMPACTS OF UPGRADING ON EMPLOYMENT IN ALBERTA** ........................................ 14  
      2.4.1. Skills Required in Refining and Upgrading in Canada ......................................................... 16  

3. **REFINING AND PETROCHEMICAL INDUSTRIES: TECHNOLOGY & TERMINOLOGY** ...... 18  
   3.1. **TECHNOLOGY AND TERMINOLOGY** .................................................................................. 18  
      3.1.1. Introduction ........................................................................................................................ 18  
      3.1.2. Key Refining Processes ....................................................................................................... 19  
      3.1.3. Types of Process Plant Configurations ................................................................................ 22  
      3.1.4. Other Essential Terminology .............................................................................................. 23  
      3.1.5. Economics of Refining and Petrochemical Production ...................................................... 23  
      3.1.6. Utilisation and Profitability: Refining and Petrochemicals .................................................. 25  
      3.1.7. The Global Refining Industry ............................................................................................... 27  
      3.1.8. The Global Petrochemical Industry ..................................................................................... 28  
      3.1.9. Conclusions: Global Trends in Refining and Petrochemicals ............................................ 29  

4. **APPROACH** ............................................................................................................................. 30  

5. **TECHNICAL REVIEW** ............................................................................................................. 31  
   5.1. **FEEDSTOCK** ....................................................................................................................... 31  
   5.2. **TECHNICAL DESIGN** .......................................................................................................... 31  
   5.3. **MASS BALANCE** .................................................................................................................. 32  

6. **SUPPLY / DEMAND AND PRICING** .................................................................................... 34  
   6.1. **OVERVIEW** ........................................................................................................................ 34  
   6.2. **CANADA** ............................................................................................................................ 34  
      6.2.1. Canada Supply / Demand for Fuel Products ....................................................................... 34  
      6.2.1. Canada Supply / Demand for Petrochemical Products ..................................................... 36  
   6.3. **US** ........................................................................................................................................ 37
List of figures

Figure 1: Structure of analysis and operating cash flow model ........................................... 3
Figure 2: Simplified process flow diagram from the 2006 Study ........................................... 4
Figure 3: Net Fuel Supply Surplus / (Deficit) by Country (2003–2013) ................................. 5
Figure 4: Net Selected Petrochemical Supply Surplus / (Deficit) by Country (2004–2013) ...... 6
Figure 5: Oil Sands Employment Outlook to 2022 by Total and by Operations Type .......... 16
Figure 6: Key Processes in a ‘Conversion’ Refinery ................................................................. 19
Figure 7: Relative values of main refined products ............................................................... 19
Figure 8: Regional Refining Net Margins and Average Utilisation (2000–2013) ................. 26
Figure 9: Global Refinery Capacity and Configuration ......................................................... 27
Figure 10: Global Ethylene Capacity and Utilisation (2004–2013) ..................................... 28
Figure 11: Structure of analysis and operating cash flow model ........................................... 30
Figure 12: Crude Oil Types – Comparison of API versus Sulphur Content ......................... 31
Figure 13: Simplified process flow diagram from the 2006 Study ........................................ 32
Figure 14: Canadian fuel product supply / demand balances (2012) ................................. 35
Figure 15: Alberta fuel product supply / demand balances (2012) ........................................ 35
Figure 16: Supply/Demand Balance of Selected Petrochemicals in Canada (2004–2013) ...... 37
Figure 17: US Refined Products 2013 Supply/Demand Balance ........................................ 38
Figure 18: Supply/Demand Balance of Selected US Petrochemicals (2004–2013) ............ 39
Figure 19: Supply/Demand Balance for Selected Asian Petrochemicals (2004–2013) ......... 40
Figure 20: China – Fuel Product Output and Consumption (1990–2013) ............................. 41
Figure 21: China – Fuel Products Imports / Exports and GDP .............................................. 42
Figure 22: Supply/Demand Balance of Selected Petrochemicals in China (2004–2013) ....... 43
Figure 23: Japan – Fuel Products Supply / Demand (1990–2013) ....................................... 44
Figure 24: Japan Fuel Product Imports and Exports ............................................................... 45
Figure 25: Supply/Demand Balance of Selected Petrochemicals in Japan (2004–2013) ...... 46
Figure 26: South Korea – Fuel Products Supply and Demand .............................................. 47
Figure 27: South Korea – Fuel Product Imports and Exports .............................................. 48
Figure 28: Supply/Demand Balance of Selected Petrochemicals in South Korea (2004–2013) 49
Figure 29: India Fuel Products Supply and Demand ............................................................. 50
Figure 30: India Fuel Product Imports and Exports ............................................................... 51
Figure 31: Supply/Demand Balance of Selected Petrochemicals in India (2004–2013) ......... 52
List of Tables

Table 1: Indicative Base Case Results .............................................................................................................7
Table 2: Results of Alternative Destination Markets .....................................................................................7
Table 3: Impact of Bitumen Feedstock Cost Discount and Capital Cost Increase .....................................8
Table 4: CAPP Canadian Oil Sands Forecast at June 2013 (thousands of barrels) .....................................11
Table 5: Percentage of Alberta Bitumen Upgraded to Synthetic Crude Oil .......................................................12
Table 6: Canada’s Oil and Gas Industry Employment from 2009 to 2012, by Sector .......................................15
Table 7: Typical Refinery Configurations .........................................................................................................22
Table 8: Project Mass Balance – Integrated Bitumen Processing ................................................................33
Table 9: Canadian and Alberta petrochemical supply / demand balance .....................................................36
Table 10: South Korean Refining Companies and their respective Distillation Capacities .........................48
Table 11: Ownership of Indian Refineries .......................................................................................................50
Table 12: Assumptions for developing refining margins .................................................................................55
Table 13: Indicative Base Case Results ..........................................................................................................55
Table 14: Base Case Assumptions ....................................................................................................................56
Table 15: Breakdown of Construction Costs (US$ billion) ............................................................................58
Table 16: WACC Calculation .........................................................................................................................59
Table 17: Assumed Transportation Costs from Alberta ($/ton or as a percentage of price) .........................60
Table 18: Scenarios for Destination Markets for Output from Plant ...............................................................60
Table 19: Results of Alternative Destination Markets ....................................................................................61
Table 20: Impact of Bitumen Feedstock Cost Discount ..................................................................................62
Table 21: Impact of Edmonton location factor uplift increase from 12% to 30% ...........................................63
## Definitions

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$</td>
<td>Refers to US Dollars, unless otherwise stated</td>
</tr>
<tr>
<td>2006 Study</td>
<td>&quot;Alberta Bitumen Processing Integration Study&quot; by David Netzer, Consulting Chemical Engineer and Associates, March 2006</td>
</tr>
<tr>
<td>AFL</td>
<td>Alberta Federation of Labour</td>
</tr>
<tr>
<td>AOSTRA</td>
<td>Alberta Oil Sands Technology Authority</td>
</tr>
<tr>
<td>API / API°</td>
<td>API Gravity</td>
</tr>
<tr>
<td>Dilbit</td>
<td>Diluted Bitumen (oil sands production mixed with condensate and / or naphtha)</td>
</tr>
<tr>
<td>c.</td>
<td>Circa</td>
</tr>
<tr>
<td>Capex</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CAPP</td>
<td>Canadian Association of Petroleum Producers</td>
</tr>
<tr>
<td>CCR</td>
<td>Continuous Catalytic Reformer</td>
</tr>
<tr>
<td>CDU</td>
<td>Crude Distillation Unit</td>
</tr>
<tr>
<td>CEG</td>
<td>CEG Europe</td>
</tr>
<tr>
<td>DWT</td>
<td>Dead Weight Tonnes</td>
</tr>
<tr>
<td>EBITDA</td>
<td>Earnings Before Interest, Taxation and Depreciation</td>
</tr>
<tr>
<td>EIA</td>
<td>US Energy Information Administration</td>
</tr>
<tr>
<td>FCC</td>
<td>Fluidised Catalytic Cracker</td>
</tr>
<tr>
<td>GDP</td>
<td>Gross Domestic Product</td>
</tr>
<tr>
<td>Hardisty</td>
<td>Hardisty Crude</td>
</tr>
<tr>
<td>HC</td>
<td>Hydrocracker</td>
</tr>
<tr>
<td>HDPE</td>
<td>High-Density Polyethylene</td>
</tr>
<tr>
<td>HDS</td>
<td>Hydrodesulphurisation</td>
</tr>
<tr>
<td>HH</td>
<td>Henry Hub</td>
</tr>
<tr>
<td>HN</td>
<td>Heavy Naphtha</td>
</tr>
<tr>
<td>HT</td>
<td>Hydro-treated or Hydro-treater</td>
</tr>
<tr>
<td>HUTF</td>
<td>Hydrocarbon Upgrading Task Force</td>
</tr>
<tr>
<td>HVGO</td>
<td>Heavy Vacuum Gas Oil</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>ISBL</td>
<td>Inside Battery Limits</td>
</tr>
<tr>
<td>Kitimat Report</td>
<td><em>Review of the Proposed Kitimat Refinery Project</em></td>
</tr>
<tr>
<td>Ktpa</td>
<td>Thousand Tons per Annum</td>
</tr>
<tr>
<td>LCO</td>
<td>Light Cycle Oil (from catalytic cracking units)</td>
</tr>
<tr>
<td>LDPE</td>
<td>Low-Density Polyethylene</td>
</tr>
<tr>
<td>LLDPE</td>
<td>Linear Low-Density Polyethylene</td>
</tr>
<tr>
<td>LN</td>
<td>Light Naphtha</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas (mainly methane)</td>
</tr>
</tbody>
</table>
LPG  Liquefied Petroleum Gas (mainly propane and/or butane)
LVGO  Light Vacuum Gas Oil
METI  Japanese Ministry of Economy, Trade and Industry
Mmbd  Million Barrels per Day
Mmbtu  Million British Thermal Units
MN  Medium Naphtha
MTBE  Methyl Tertiary Butyl Ether
Mtpa  Million Tons per Annum
NGL  Natural Gas Liquids
NPV  Net Present Value
OH  Overheads (i.e. gases or light ends)
OSBL  Outside Battery Limits
pa  Per Annum
PE  Polyethylene
Project  Proposed Alberta Oil Sands Processing Complex
PSU  Indian Public Sector Undertaking (i.e. a state-owned company)
SCO  Synthetic Crude Oil
USGC  US Gulf Coast
VDU  Vacuum Distillation Unit
VGO  Vacuum Gas Oil
VLCC  Very Large Crude Carrier
VTB  Vacuum Tower Bottoms
WACC  Weighted Average Cost of Capital
WCS  Western Canada Select
WTI  West Texas Intermediate
DISCLAIMER

CEG Europe and its authors make no representation or warranty as to the accuracy or completeness of the material contained in this document and shall have, and accept, no liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document or any omissions from this document, or any other written or oral communication transmitted or made available to any other party in relation to the subject matter of this document.
1. **EXECUTIVE SUMMARY**

1.1. **INTRODUCTION**

The Government of Alberta has been looking at potential upgrading projects for a number of years in order to try and add value to the hydrocarbon resources prevalent in the region. These studies have been under the mandate of the Hydrocarbon Upgrading Task Force ("HUTF"), a joint government and industry initiative to develop business cases and promote opportunities for new refining and petrochemical investment in Alberta. The HUTF was established in February 2004.

In 2006, the Government of Alberta, under the HUTF, retained David Netzer, Consulting Chemical Engineer, to develop a conceptual design for an integrated bitumen upgrading, refining and petrochemical complex in Alberta – “Alberta Bitumen Processing Integration Study” by David Netzer, Consulting Chemical Engineer and Associates, March 2006 (the “2006 Study”)¹. This study built on previous reviews with the aim of assessing whether an integrated complex transforming bitumen into a variety of high value products is technically feasible.

Up until early 2013 the Government of Alberta had not made any further assessments of the concept.

In late March 2013 the Alberta Federation of Labour (“AFL”) approached Edward Osterwald (now a Partner with CEG Europe in London) to assess the potential economics of such an “in-province upgrading, refining, and associated value-added petrochemical complex” using the configuration set out in the 2006 Study. The request followed publication of Mr Osterwald’s appraisal of a proposed green field oil sands refinery on the west coast of Canada at Kitimat, on behalf of the Government of British Columbia (“Review of the Proposed Kitimat Refinery Project”²). That report was published on 14 March 2013, at which time Mr Osterwald was a Managing Director with Navigant Consulting.

The objective of the current study for AFL is to examine the potential economics of in-province upgrading of oil sands produced within Alberta and whether such a project that should be looked at in more detail.

1.2. **ALBERTA OIL SANDS**

In 2011, oil sands production in Alberta was 1.7 million barrels per day (“mmbd”). Published estimates suggest that production may increase by around 1.0 mmbd to 2.7 mmbd by 2016³. Although we understand there currently appears to be additional capacity in existing pipelines,

¹ http://www.energy.alberta.ca/EnergyProcessing/pdfs/albertaintegrationreport.pdf
³ Economic Impacts of New Oil Sands Projects in Alberta (2010 - 2035); Canadian Energy Research Institute, May 2011
In Province Upgrading Economics of a Green-field Oil Sands Refinery

based on existing projections of oil sands production increases, by around 2020 new capacity is likely to be required in order to export all anticipated production.

Despite being a major oil producer, Alberta faces two major dilemmas. One is how to ensure that already planned oil sands production can be delivered to market. The other is to find ways to enhance the economic benefits of this output for the Province. To date, most oil sands production has been upgraded to syncrude and exported, with additional processing taking place in Alberta. Although additional refining capacity within the Province is an obvious possibility, it has been over 30 years since a new fuel refinery was constructed in Alberta.

At present, Alberta’s economy is highly dependent on mineral resource production and export, such as oil sands. The level of value added processing is limited compared with other developed countries. Therefore the impact of the recent financial crisis on the Province was much more pronounced that the rest of Canada.

The issues around adding value to an industry based on exports of commodities has been faced by many countries that produce a surplus of hydrocarbons and have relatively small populations. Canada differs, however, by already having a highly developed economy and a skilled workforce, as well as proximity to the largest economy in the world. Nevertheless, it needs to find ways to ensure that the benefits of Alberta’s oil reserves are captured and not simply exported.

1.3. Approach

Our approach to assessing the potential economics of the proposed Alberta oil sands processing complex (the “Project”) was to develop a preliminary high level operating cash flow model, using information set out in the 2006 Study where relevant, and making various additional assumptions.

In our initial discussions on scope with AFL, we it was agreed that our assessment would use the same mass balance / yield assumptions as set out in the 2006 Study. However, we have developed our own assumptions around a number of areas, including pricing and transportation costs.

Details of the components of the project and the associated sequence are shown in Figure 1 below.

---

4 “Syncrude” refers to synthetic crude, the result of the process of upgrading bitumen. The product is also variously referred to as “synthetic crude oil,” “SCO,” or simply “synthetic.” This product is distinct from bitumen or heavy crude oils. Synthetic crude can be processed by traditional cracking-configuration refineries and, under these conditions, can yield a slate of petroleum products: gasoline, jet fuel, and diesel. Bitumen and heavy crudes require more complex refinery configurations in order to yield higher-priced products like gasoline, jet fuel, and diesel. Absent a complex refinery with coking capacity, bitumen and heavy crudes can typically only yield heating fuel, which is a lower-priced commodity and typically in lower demand than transportation fuels.

5 The North West Upgrader is the closest the province has come to new upgrading/refining and heavy oil conversion capacity. A product of public policy (the “Bitumen-Royalty-In-Kind” program, established under the Alberta Petroleum Marketing Act, the North West Upgrader project will use bitumen to produce diesel. The first phase of the project is expected to come onstream in September 2017.
1.4. TECHNICAL REVIEW

The bitumen being considered as feedstock for the Project would be similar to a Western Canada Select ("WCS") blend – this would be after the oil sands have been mixed with the diluent. Oil sands blend such as Hardisty and WCS fall into the low API\textsuperscript{6}, high sulphur content group of crudes, which would make their processing more complex, when compared to the lighter sweeter crudes such as Brent or WTI.

Given the complexities around processing oil sands blends, the proposed design represents a clever solution that balances many competing constraints, including low feedstock quality, the need to minimise capital cost and meet environmental requirements, while still producing saleable products. Most importantly, since fuels upgraded from coker products are poor quality (i.e. low octane naphtha, low cetane and hydrogen deficient), Mr Netzer has suggested that the coke instead be converted to syngas through partial oxidation. This would generate hydrogen for use elsewhere in the complex and facilitate ammonia production.

\textsuperscript{6} American Petroleum Institute (API) gravity is a measure of how heavy or light a petroleum liquid is compared to water.
A high level process flow diagram of the 2006 Study’s configuration is shown in Figure 2 below. It uses a combination of catalytic and thermal cracking, together with partial oxidation, to generate both transportation fuels and feedstock for petrochemical production.

Figure 2: Simplified process flow diagram from the 2006 Study

![Process Flow Diagram]

Source: 2006 Study

It was agreed at the outset that our assessment of the likely economic performance of in-province upgrading would use the mass balance from the 2006 Study. As such, we did not consider alternatives or sensitivities based on changes to the proposed feedstock or output configurations.

A key element within the proposed processing plant is that diluted bitumen will be delivered to the complex near Edmonton. Following atmospheric distillation, the diluent (condensate or naphtha-equivalent) will be recycled to oil sands production sites elsewhere in Alberta. Therefore the “diluent” appears in the mass balance as both a feedstock and product.

1.5. Supply / Demand and Pricing

In order to assess the alternate value of each of the main sales products from the proposed complex in Alberta, it was important to understand the supply / demand balance of each, from both a provincial and all-Canada perspective, as well as different regions. We therefore compiled recent statistics of the net trade balance for the fuel and petrochemicals for these areas based on information published by Statistics Canada. In addition, we reviewed the supply / demand balance for the products for the US and certain Asian countries.

Based on current supply / demand balances and a high level understanding of currently planned and projected new plants, one can assess whether a target market will be in surplus or deficit of certain products in the medium term, and whether the economics of sales into that particular market will be achievable, given the associated transportation costs.
Figure 3 below shows the net fuel supply surplus / (deficit) by country for the years 2003 to 2013. As the graph shows, the US, China and Japan were generally in fuels deficits up to 2010. Since then the Canadian fuels market has moved towards a position of being either balanced or slightly in surplus (see Figure 14). The US remains in deficit, but to a lesser extent, mainly for gasoline and this may decrease in the medium to long term. The Chinese market is likely to remain in deficit for the foreseeable future and to a lesser extent Japan.

**Figure 3: Net Fuel Supply Surplus / (Deficit) by Country (2003–2013)**

![Net Fuel Supply Surplus / (Deficit) by Country (2003–2013)](image)

*Source: US Energy Information Administration, CEG analysis*

Figure 4 below shows the net supply surplus / (deficit) for a combination of propylene, benzene, toluene and xylene by country for the years 2004 to 2012. China has been the main market that has generally been in deficit historically, and the general predictions are that China will continue to be a net importer of for propylene, benzene, toluene and xylene at least for the medium term, if not longer.
Although Asia, particularly China, could be a focus market for a potential North American exporter, it is important to note that markets in Japan, South Korea and China are not easy for outsiders to penetrate. For a North American producer to do so, collaboration with one or more local refining, petrochemical or LPG distribution companies might make sense.

### 1.6. ECONOMICS OF IN-PROVINCE UPGRADING OF OIL SANDS

We used information from the 2006 Study to develop an operating cash flow model of the proposed Project along with other factors, such as CEG’s price forecasts, discount rate and projected fixed and variable costs.

Various assumptions are implicit in our Base Case. One of the most important is that the diluent return stream would be sold to oil sands producers at a market-related transfer price, namely WTI plus 5%. The results of the Base Case are set out in Table 1 below.

---

7 Combination of propylene, benzene, toluene and xylene.
Table 1: Indicative Base Case Results

<table>
<thead>
<tr>
<th>WTI Price</th>
<th>NPV @ 8.9% real</th>
<th>IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>$80</td>
<td>$12.1 billion</td>
<td>19.0%</td>
</tr>
<tr>
<td>$100</td>
<td>$17.5 billion</td>
<td>22.6%</td>
</tr>
<tr>
<td>$120</td>
<td>$22.8 billion</td>
<td>25.6%</td>
</tr>
</tbody>
</table>

Source: CEG analysis

Based on existing capital cost estimates and arms-length purchase of feedstock at market prices, the Project is appears to be attractive, with NPV and IRR, showing good returns under all three crude oil price cases.

In addition to the Base Case, we ran some alternative scenarios and sensitivities. The scenarios looked at the impact on the economics of supplying product into alternative markets, as follows:

- **Scenario 1**: fuel and petrochemicals products into Canada;
- **Scenario 2**: fuel products into USA and petrochemicals in Alberta; and
- **Scenario 3**: fuel and petrochemicals products into Asia.

The results of these scenarios, set out in Table 2 below, show that although it is less profitable than the Base Case, the Project economics remain attractive.

Table 2: Results of Alternative Destination Markets

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$80/bbl NPV ($ billion)</th>
<th>IRR (%)</th>
<th>$100/bbl NPV ($ billion)</th>
<th>IRR (%)</th>
<th>$120/bbl NPV ($ billion)</th>
<th>IRR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>12.1</td>
<td>19.0%</td>
<td>17.5</td>
<td>22.6%</td>
<td>22.8</td>
<td>25.6%</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>7.8</td>
<td>15.9%</td>
<td>12.6</td>
<td>19.3%</td>
<td>17.1</td>
<td>22.2%</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>8.3</td>
<td>16.2%</td>
<td>12.8</td>
<td>19.4%</td>
<td>17.0</td>
<td>22.2%</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>7.8</td>
<td>15.9%</td>
<td>12.5</td>
<td>19.2%</td>
<td>16.8</td>
<td>22.0%</td>
</tr>
</tbody>
</table>

Source: CEG analysis

Given its inland location and the potential transportation costs required for alternative markets, it appears that the plant is best suited to supply local areas, should there be sufficient demand.

However, based on the current supply / demand outlook for Canada and the US, both markets are unlikely to be in deficit. Table 2 above shows that Scenario 3, which looks at supplying product into the Asian market, still shows reasonable returns under all the crude pricing scenarios, despite the logistics involved.

There are numerous variables and assumptions that can have an impact on the potential value of the Project. However at this stage, there are two key items whose variation can have a significant impact on the Project and its potential viability, namely the bitumen feedstock price and capital costs (through the Edmonton location factor uplift being used).
We ran sensitivities around both these variables as set out in Table 3 below.

### Table 3: Impact of Bitumen Feedstock Cost Discount and Capital Cost Increase

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$80/bbl</th>
<th></th>
<th>$100/bbl</th>
<th></th>
<th>$120/bbl</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NPV ($ billion)</td>
<td>IRR</td>
<td>NPV ($ billion)</td>
<td>IRR</td>
<td>NPV ($ billion)</td>
<td>IRR</td>
</tr>
<tr>
<td>Base Case</td>
<td>12.1</td>
<td>19.0%</td>
<td>17.5</td>
<td>22.6%</td>
<td>22.8</td>
<td>25.6%</td>
</tr>
<tr>
<td>10% Feedstock Discount</td>
<td>17.3</td>
<td>22.5%</td>
<td>24.2</td>
<td>26.5%</td>
<td>30.8</td>
<td>30.0%</td>
</tr>
<tr>
<td>20% Feedstock Discount</td>
<td>22.5</td>
<td>25.7%</td>
<td>30.8</td>
<td>30.2%</td>
<td>38.8</td>
<td>34.0%</td>
</tr>
<tr>
<td>15% Capex increase</td>
<td>10.9</td>
<td>17.2%</td>
<td>16.4</td>
<td>20.5%</td>
<td>21.7</td>
<td>23.4%</td>
</tr>
</tbody>
</table>

*Source: CEG analysis*

Table 3 above shows that a modest price discount of 10% increases NPV by between c.$5 billion to c.$8 billion, depending on the crude oil price scenario, with a corresponding uplift in IRR of between c.3.5% to c.4.4%.

Given the potential for a very tight construction market in North America in the medium term, we have run the possible impact on the Project economics from an increase in the Edmonton location factor from 12% to 30%. This equates to a 15% overall increase in the capital cost of the Project from $10.2 billion to $11.7 billion. The impact of the capex increase reduces NPV by c.$1.1 billion under all three crude oil pricing scenarios, with IRR decreasing by between 1.8% and 2.2%.

The Government of Alberta has the flexibility to adjust the cost of oil sands to users (through the Bitumen Royalty in Kind Program). Discounts on feedstock prices could be used, if necessary, to improve returns, should there be cost increases in other risk areas (e.g. capital costs, etc.).

### 1.7 CONCLUSIONS

Our analysis of the economics of an in-province upgrading refinery and petrochemical complex in Alberta suggests that it is likely to be profitable and generate favourable economic returns. So much so, in fact, that it would meet many of the criteria necessary to attract investment from the private sector. There are several factors that work in the project’s favour, including:

- Mr Netzer’s configuration uses partial oxidation to eliminate heavy residues and reduce the amount of hydro-processing of fuel products derived from oil sands;
- The market value of oil sands at Hardesty is quite low; return diluent streams are valued at higher naphtha-related alternate value; and
- The complex would have the capability to maximise margins by selling into a variety of end-user markets (i.e. Alberta, Canada, the US and Asia), as necessary to optimise profitability.
On the basis that this project is commercially attractive and viable, the onus is likely to be on the Government of Alberta to move it forward, at the initial stages at the very least. The Government could act as the conduit or aggregator of feedstock that could sell the bitumen to local upgrading plants. Incentive mechanisms already in place may be used to allow the Government to do this.

Furthermore, incentives (such as discounted feedstock prices) may also be used to encourage the private sector to assume a greater role in development of the Project. Alternatively, the Government may have to initiate the process on its own or through a partnership with the private sector. Although there may be an initial cost to these incentives, over the medium to long term it is likely to benefit the Province, both in financial and non-financial terms (such as job creation and less dependency on the upstream sector).

Given these favourable economics, it is perhaps surprising that the private sector has, to date, not taken a greater interest in such a project. There are many factors at work, such as:

- Much of the existing oil sands production has been processed in existing refining capacity, both in Canada and the US.
- Likewise, to date there has been sufficient pipeline capacity to deliver oil sands to consumers. As output in Alberta continues to increase, however, the capability to deliver to buyers outside the Province may become constrained (e.g. if the Keystone and / or Trans Canada pipelines are not constructed), in which case the Project would assume greater importance to both Alberta and Canada as well.
- Until recently, refining margins in North America were quite low. The international integrated companies have been scaling back downstream operations and focusing on the upstream sector. Similarly smaller midsize companies have been focusing on consolidating existing assets through acquisitions and restructuring.
- The emergence of shale oil production in the US, beginning in 2012, created a steadily rising surplus of crude oil that under current law cannot be exported. This has caused crude prices in the US to drop sharply, so much so that they are disconnected from world oil markets. In turn, there has been a surge in refining profitability.
- Our analysis of in-province upgrading of Canadian oil sands shows a similar pattern. Surplus production in Alberta may become increasingly difficult to export, so the value of oil sands output in the Province will decline. This will, in much the same way as refining in the US, cause the profitability of upgrading to improve.

It may be appropriate for Government, through the use of appropriate incentives and / or joint venture partners, to take a prominent role in encouraging investment in oil sands upgrading. The objective would be to sell finished products into a variety of export markets, as required to maximise margins at the upgrading complex in Alberta.
2. DEVELOPMENT OF OIL SANDS IN ALBERTA

2.1. INTRODUCTION

Alberta’s oil sands are one of the largest recoverable petroleum reserves in the world. At 169 billion recoverable barrels of bitumen, Alberta’s bituminous sands are rivaled only by Saudi Arabia and Venezuela.8

2013 production of Alberta oil sands was nearly 2 million barrels per day. Production is slated to increase to 3.2 million barrels per day by 2020. Bullish predictions by the Canadian Association of Petroleum Producers and the Canadian Energy Research Institute estimate production of 5 million barrels per day by 2030, although these long-range estimates have been consistently subject to downward revision.9

Of Alberta’s current production, approximately 55% is upgraded to synthetic crude oil (“SCO”) before leaving the province. However, the Government of Alberta predicts the percentage of upgraded product to drop precipitously in the coming decade. By 2025, Government of Alberta experts indicate just 26%10 will be upgraded in-province while the rest will be exported:

- to upgrading and refining facilities on the US Gulf Coast as diluted product via pipeline (such as via the Keystone XL pipeline proposed by TransCanada11) and relatively undiluted product via heated rail car; or
- to proposed marine export terminals in Kitimat (via the approved Enbridge Northern Gateway pipeline); or
- to the Port of Vancouver (via the expansion of the TransMountain pipeline proposed by Kinder Morgan); or
- New Brunswick (via the Energy East pipeline proposed by TransCanada).

Unlike other heavy oil deposits, the “Athabasca tar sands,” as they were originally known, are fairly shallow and therefore more easily recoverable than comparable reserves found in places like Venezuela.

---


11 Awaiting US approval at time of writing.
However, Alberta’s oil sands required public support to develop to the point where they now account for one of the world’s largest sources of hydrocarbon-based fuels. The Government of Alberta or the Government of Canada have:

- played a role in establishing Great Canadian Oil Sands (“Suncor”) and later the Syncrude consortium;
- established the Alberta Oil Sands Technology Authority (“AOSTRA”), a Crown corporation. AOSTRA pioneered research and development into in-situ extraction technologies, making it possible for the private sector to access deeper bitumen deposits and bringing down the per-barrel cost of production;
- introduced the capital cost allowance and other tax incentives for oil sands projects, resulting in an estimated $2 billion in foregone revenue per year; the Federal Department of Finance estimates that for every $1 billion in investment, the Provincial and the Federal governments have received oil taxes and royalties which have allowed them to deliver between $5m and $40m in tax cuts to other areas;
- introduced the 1% generic royalty regime in 1997, resulting in a reduction of royalty payments of between 20% and 30% for oil sands operators from Lougheed-era royalty payments; and
- Although oil sands production increased 133% between 1995 and 2004, government royalties decreased by 30%.

2.2. **Oil Sands Development**

2.2.1. **In-situ oil sands developments**

Historically, the majority of oil sands production came from surface mining extraction. In-situ production methods have grown significantly in recent years and they are poised to outpace surface mining going forward. This is illustrated in the forecasts in Table 4 below.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mining</td>
<td>906</td>
<td>976</td>
<td>984</td>
<td>1,007</td>
<td>1,044</td>
<td>1,095</td>
<td>1,123</td>
<td>1,227</td>
</tr>
<tr>
<td>In-situ</td>
<td>1,079</td>
<td>1,182</td>
<td>1,296</td>
<td>1,436</td>
<td>1,546</td>
<td>1,671</td>
<td>1,823</td>
<td>1,996</td>
</tr>
</tbody>
</table>

Source: [Canadian Association of Petroleum Producers, Crude Oil Forecast, Markets, and Transportation](http://www.capp.ca/forecast/Pages/default.aspx)

2.2.2. **Government of Alberta Policy on Upgrading Bitumen**

The provincial Government has historically taken an active interest in developing incentives to encourage upgrading Alberta’s bitumen to SCO. Until recently, it was stated Government of Alberta policy to ensure that two-thirds of bitumen was upgraded in Alberta before exiting the Province.

---

12 CAPP Crude Oil Forecast, Markets, and Transportation accessed at: [http://www.capp.ca/forecast/Pages/default.aspx](http://www.capp.ca/forecast/Pages/default.aspx)
This policy has since been downgraded to an “aspirational goal.”\(^\text{13}\) Nevertheless, it is apparent that in the coming years the proportion of bitumen that will be upgraded to synthetic crude oil will steadily decline.

| Table 5: Percentage of Alberta Bitumen Upgraded to Synthetic Crude Oil |
|-----------------------------|---------------------|---------------------|---------------------|---------------------|
|                             | 2011                | 2012                | 2017                | 2025                |
| Percent converted to SCO    | 57%\(^\text{14}\)    | 52%\(^\text{15}\)    | 50%                 | 26%\(^\text{16}\)   |


2.3. **BACKGROUND TO UPGRADING**

Given this policy, it is not surprising that the Government of Alberta has been looking at potential projects in the hydrocarbon upgrading industry for a number of years in order to try and add value to the hydrocarbon resources prevalent in the region. These studies have been under the mandate of the HUTF.

In 2006, the Government of Alberta, under the HUTF, retained David Netzer, Consulting Chemical Engineer to develop a conceptual design for an integrated bitumen upgrading, refining and petrochemical complex in Alberta – “Alberta Bitumen Processing Integration Study” by David Netzer, Consulting Chemical Engineer and Associates, March 2006. This study built on previous reviews with the aim of assessing whether an integrated complex transforming bitumen into a variety of high value products is technically feasible.

The 2006 Study suggested that such a plant was feasible at a conceptual level but would require further detailed analyses (such as engineering and cost estimates). The 2006 Study also suggested that there may be a number of potential benefits for such an integrated complex, being:

- Significant savings in capital and operating costs based on synergies among the different processing steps;
- Significant reduction in environmental footprints including management of emissions and waste streams; and
- Improved overall economics based on transforming low-cost bitumen into a variety of higher valued products.

As of early 2013 the Government of Alberta had not made any further assessments of the concept.

---


In late March 2013 the Alberta Federation of Labour approached Edward Osterwald (now a Partner with CEG Europe in London) to assess the potential economics of such an “in-province upgrading, refining, and associated value-added petrochemical complex” as the one set out in the 2006 Study.

The request followed publication of Mr Osterwald’s appraisal of a proposed green field refinery on the west coast of Canada at Kitim, on behalf of the Government of British Columbia. That report was published on 14 March 2013, at which time Mr Osterwald was a Managing Director with Navigant Consulting.

The objective of the current study for AFL is to examine the potential economics of in-province upgrading of oil sands produced within Alberta and whether this is a project that should be looked at in more detail. It was agreed at the outset that an independent assessment of prices for fuel products and chemical production would be developed. The technical specifications and mass balance, however, were to be based on those set out in the 2006 Study.

Despite being a major oil producer, Alberta faces two major dilemmas. One is how to ensure that already planned oil sands production can be delivered to market. The other is to find ways to enhance the economic benefits of this output for the Province. To date, most oil sands production has been upgraded to syncrude and exported, although some processing takes place in Alberta (such as at Shell Scotford17). Although additional refining capacity within the Province is an obvious possibility, it has been over 30 years since a new fuels refinery was constructed in Alberta.

Interestingly this problem has been faced by many countries that produce a surplus of hydrocarbons and have relatively small populations. Canada differs, however, by already having a highly developed economy and a skilled workforce, as well as proximity to the largest economy in the world. Nevertheless, it needs to find ways to ensure that the benefits of Alberta’s oil resources are captured and not simply exported.

2.3.1. Upgraders, the Great Recession, and Foreign Direct Investment

Six upgrader projects in Alberta were canceled during the 2008-2010 credit crisis and subsequent recession. Prior to this time, capital and labour costs had soared in Alberta, due to the rapid expansion of oil sands development. High costs were blamed for the cancellation of many of the upgrader projects. Industry consensus at the time was that green field upgrading would be less profitable than conversion in existing physical plants elsewhere.

Subsequent analysis has shown that while there was only 20% growth in wages during the 2005-2008 boom period, major integrated oil sands projects were between 50% and 260% over the initial cost projections. Much of this has been blamed upon productivity and availability of skilled labour, and cost of inputs, particularly steel.18

17 In 1984, Shell opened the Scotford Refinery and Chemicals plant (styrene). As one of North America’s most modern and efficient refineries, the Scotford Refinery was the first to exclusively process synthetic crude oil from Alberta’s oil sands.
18 http://www.andrewjohns.ca/sites/default/files/Energy Oil Sands Time to Reassess Growth Expectations...Again.pdf
Another important factor arose from much of the new investment in Alberta’s oil sands being part of joint ventures between companies who have, or are developing, value-adding process plant elsewhere. For example, total installed costs are up to 30% lower to build a green field upgrader/refinery complex in China, relative to Alberta.¹⁹

### 2.3.2. If In-Province Upgrading Were Profitable, Why Isn’t Industry Doing It?

Nevertheless, the analysis in this report demonstrates that upgrading and refining of oil sands production in Canada could generate satisfactory financial returns. The added benefits of job creation, energy security and contributions to expanding other parts of the provincial economy would be significant as well, thus enhancing the potential benefits of appropriate public participation in upgrading/refining in Alberta.

It is worth noting that refining profitability in the US collapsed during the 2008 – 2011 recession due to a short term market dislocation. Many international companies responded, however, by closing or selling refining capacity. This has turned out to be a very poor decision. The surge in US shale oil production beginning in 2012, coupled with the long-standing ban on crude oil exports from the United States, has resulted in an unprecedented surge in refining profitability. This illustrated in Figure 8 on page 26 below.

Thus the argument that the lack of current investment in upgrading and refining in Alberta is a reflection of poor upgrading economics is fundamentally flawed. It seems that in-province upgrading may be an attractive option for the Province to pursue, which already benefits from a sophisticated workforce and well developed infrastructure.

Indeed, investments in upgrading and refining in Alberta may exhibit a sufficiently high after tax internal rate of return to meet or exceed the minimum threshold returns used by many multinational oil and chemical companies when they consider investments in the process industries.

### 2.4. Impacts of Upgrading on Employment in Alberta

#### 2.4.1. Oil Sector Employment Trends in Alberta

Oil sands extraction led Canada’s petroleum sector in overall percentage growth in employment between 2009 and 2012. However, country-wide, oil and gas services and conventional exploration and production remain larger employers than Alberta’s oil sands. This is shown in Table 6 below.

---

http://www.ogi.com/articles/2013/03/ihs--prospects-have-dimmed-for-bitumen-upgraders-in-alberta.html
Table 6: Canada’s Oil and Gas Industry Employment from 2009 to 2012, by Sector\textsuperscript{20}

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas services</td>
<td>82,900</td>
<td>90,400</td>
<td>94,100</td>
<td>3,700 4%</td>
</tr>
<tr>
<td>Conventional E&amp;P</td>
<td>69,900</td>
<td>75,600</td>
<td>72,000</td>
<td>-3,600 -5%</td>
</tr>
<tr>
<td>Oil sands</td>
<td>17,700</td>
<td>20,300</td>
<td>22,300</td>
<td>2,000 10%</td>
</tr>
<tr>
<td>Pipelines</td>
<td>6,500</td>
<td>6,700</td>
<td>6,800</td>
<td>100 1%</td>
</tr>
<tr>
<td>Total</td>
<td>177,000</td>
<td>193,000</td>
<td>195,200</td>
<td>2,200 1%</td>
</tr>
</tbody>
</table>

Source: Petroleum Human Resources Council of Canada\textsuperscript{21}

In 2012, there were 22,300 direct extraction jobs in Alberta’s oil sands.\textsuperscript{22} Alberta’s oil sands employment can be apportioned into the following categories:

- 40% in mining;
- 40% in in-situ operations; and
- 20% in upgrading.

2.4.2. Forecast Growth in Alberta’s Oil Sands Employment

Figure 5 below shows that the majority of the growth in projected oil sands employment will be in in-situ extraction operations and to a lesser extent mining operations. Upgrading employment is forecast as relatively flat.

\textsuperscript{20} Data sources from Labour Force Survey (LFS) and industry surveys; numbers have been normalised and rounded. Upgrading and refining jobs are contained in the “Conventional E&P” data.

\textsuperscript{21} The Decade Ahead: Labour Market Outlook to 2022 for Canada’s Oil and Gas Industry. Petroleum Human Resources Council of Canada. May 2013. P.8

\textsuperscript{22} Ibid.
2.4.1. Skills Required in Refining and Upgrading in Canada

Upgrading bitumen and oil refining involve different processes. Upgrading blended bitumen to SCO and refining SCO or light crude to gasoline, diesel and/or further petrochemical processing, however, share some key economic characteristics, being:

- capital intensity;
- ongoing need for highly-skilled labour; and
- high wages relative to other industry sectors.

According to the Conference Board of Canada, refining exhibits the following workforce characteristics:

- An average of 3,500 Albertans employed in refining between 2006 and 2009.
- Over two-thirds (73%) of workers in refining have a post-secondary qualification, including 20% who hold at least a bachelor’s degree.
- Pre-tax returns for the refining industry (profits) have averaged 11% over 10 years.

Source: Petroleum Human Resources Council of Canada

---

• Wages are some of the highest in Canada. Average weekly earnings were in the region of $1,400 in 2009 - that compares to c.$820 for all industries. In 1991, a worker in the refining industry earned about 50% more than the Canadian average. Now a worker in this industry earns two thirds more than the average worker.

• Wage growth in refining was not affected by the 2008-09 recession. Average weekly earnings in refining increased by c.5% and c.7% in 2008 and 2009 respectively. In contrast, the industry composite index increased by only 2.2% on an annual average basis over those two years.24

• According to the Petroleum Human Resources Council, 3,500 Albertans work in upgrading.

---

3. **Refining and Petrochemical Industries: Technology & Terminology**

3.1. **Technology and Terminology**

3.1.1. Introduction

To appreciate the commercial and technical issues relevant to the Project, it is important that readers develop a high level understanding of the key steps in hydrocarbon processing, as well as the applicable terminology. In so doing, readers will be better placed to consider the Project in the context of the global oil market in which it may eventually compete. This section therefore explains some of the technology employed to convert hydrocarbon feedstock, such crude oil or bitumen, into saleable products that can be used as fuel, lubricants or to manufacture chemicals.

Feedstock is a mixture of hydrocarbon molecules of various weights, sizes and shapes. To be converted into saleable products, they need to be separated into lighter fractions (through distillation), reshaped to more useful structures (reforming, mainly for gasoline) or broken into smaller molecules (cracking). Refiners use combinations of these processes to achieve the desired results.

Petrochemicals are manufactured from certain gases, most notably ethane (to crack into ethylene), or intermediate products from refining. Of the latter, naphtha is crucial because it is an important feedstock in ethylene production and is used as a source of aromatics for many types of chemicals.

The main steps in fuel refining are presented in Figure 5 below. They are explained in the text thereafter.

---

25 An aromatic is a particular shape of hydrocarbon molecule with alternating double and single bonds between carbon atoms forming rings.
### 3.1.2. Key Refining Processes

**Atmospheric and Vacuum Distillation**

In a crude distillation unit (“CDU”), crude oil is heated in a furnace and then fed into a vertical distillation column that contains horizontal trays. The trays are used to separate the volatile hydrocarbons into a range of fractions, due to variations in boiling points. For example, lighter molecules, such as gases (e.g. propane, butane, etc.) are taken out at the upper levels of a CDU.
Heavier fractions migrate to the bottom. The densest residual material is extracted from the bottom of the atmospheric distillation unit (termed “heavy residue”). By heating and then distilling the residue in a column under reduced pressure (i.e. a vacuum distillation unit or VDU), it is quite straightforward to separate higher boiling range materials in the upper levels of the vacuum column. Side streams from the VDU include vacuum gasoil (VGO), which is the main feedstock for catalytic cracking units.

Due to impurities, the products from atmospheric or vacuum distillation are rarely suitable for end use, therefore they need to be further processed.

**Cracking**

Cracking units mix vacuum gas oil and highly specialised catalysts, under high pressure and heat, to break down the VGO into lighter, more valuable products. Generally speaking, there are three types of catalytic crackers:

- **Fluidised catalytic cracking (FCC):** catalysts are “fluidised” with VGO, to convert VGO into components suitable for gasoline and other products;
- **Hydrocracking (HC or hydrocracker):** large quantities of hydrogen, again at very high temperatures and pressures, react over a catalyst with VGO to produce middle distillates, mainly diesel and jet fuel; and
- **Steam cracking:** ethane, propane and / or naphtha, in the presence of high pressure steam and high temperatures, are converted to olefins that are essential in production of polymers and plastics.

**Catalytic Reforming**

Reforming is a key process in gasoline production. Heavy naphtha from the distillation unit is treated with a catalyst at high temperatures. The molecules are reshaped (“reformed”) which enhances their octane content; higher octane fuels burn better in spark ignition gasoline engines without “knocking” or pre-ignition. Not surprisingly, the main product of catalytic reforming is termed “reformate.” It is a high octane blending component in gasoline.

**Isomerisation**

The isomerisation unit uses catalysts to convert lighter streams such as light naphtha to higher-octane branched molecules for blending into gasoline or feed to alkylation units.

**Coking**

A coker upgrades the residues or bottoms from the atmospheric or vacuum distillation column into higher-value products, with a final residual product called petroleum coke (a coal-like material that can be used as a fuel source, similar to coal).

---

26 Items such as ethylene, propylene, and butylene
Two types of coking processes exist—delayed coking and fluid coking. Both are physical processes that occur at pressures slightly higher than atmospheric and at temperatures greater than $480^\circ C$ that thermally crack the residue into products such as naphtha and distillate, leaving behind petroleum coke. Depending on the quality of the residue being coked (high or low sulphur, high or low metals content, etc.), the coking operation temperatures and the length of coking times, petroleum coke is either sold as fuel-grade petroleum coke or can undergo an additional heating or calcining process to produce anode-grade petroleum coke, but only in the case of low sulphur, low metals coke.

**Hydrotreating or hydrodesulphurisation**

Fuel specifications around the world are requiring refiners to steadily reduce the amount of sulphur in fuels. Thus sulphur removal (or desulphurisation) is one of the most essential steps in modern refineries. It also relies on the availability of large quantities of hydrogen.

More specifically, desulphurisation is achieved by reacting products and catalysts, in the presence of hydrogen, at elevated temperatures and pressures. This is referred to as “hydrodesulphurisation (“HDS”) and is carried out in an HDS unit.

**Other Processes**

There are a number of other process units that can be included within refinery configurations, which are explained briefly below.

- **Alkylation unit**: is used to convert isobutane and low-molecular-weight alkenes (primarily a mixture of propene and butene) in the presence of a strong acidic catalyst. Alkylation processes transform low molecular-weight alkenes and iso-paraffin molecules into larger iso-paraffins with a high octane number. The product of the unit is called alkylate and is composed of a mixture of high-octane, branched-chain paraffinic hydrocarbons (mostly isoheptane and isooctane). Alkylate is a premium gasoline blending stock because it has exceptional antiknock properties and is clean burning. There are other products in the alkylate, so the octane rating will vary accordingly.

- **Methyl Tertiary Butyl Ether (“MTBE”) unit**: MTBE is used for blending into gasoline, as it is an octane enhancer and has a high oxygen content. The MTBE unit reacts isobutene with methanol over a catalyst bed. The isobutene can be obtained from a number sources: a C4 stream from a steam cracker with the butadiene removed (known as Raffinate-1 which is a mixture of isobutene and 1- and 2-butenes); butene-butane fractions from a catalytic cracker; and n-butane (from LPG) which is isomerised to isobutane and then dehydrogenated to isobutene.
• **Visbreaking unit**: uses a mild form of thermal cracking to reduce the quantity of residual oil produced in the distillation of crude oil and to increase the yield of more valuable middle distillates (heating oil and diesel) by the refinery. The process uses thermal cracking (i.e. is non-catalytic) of large hydrocarbon molecules in the crude at high temperatures to reduce viscosity and to produce small quantities of light hydrocarbons (LPG and gasoline). The process name of “visbreaker” refers to the fact that the process reduces (i.e. breaks) the viscosity of the residual oil.

### 3.1.3. Types of Process Plant Configurations

It is worth noting that all oil refineries are unique, in the sense that each one was designed and built to meet the specific environment in which it operates. Thus not only are no two alike, but more importantly the levels of complexity and sophistication vary widely. Nevertheless, over time the industry has developed terminology to describe common combinations of process units, as set out in Table 1 below.

<table>
<thead>
<tr>
<th>Complexity</th>
<th>Description Used by Industry</th>
<th>Typical Process Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very simple</td>
<td>Topping</td>
<td>CDU</td>
</tr>
<tr>
<td>Simple</td>
<td>Hydroskimming</td>
<td>CDU, HDS, Reforming</td>
</tr>
<tr>
<td>Complex</td>
<td>Conversion</td>
<td>CDU, HDS, Reforming, VDU, FCC, HC, Isomerisation, Alkylation, MTBE, Visbreaking.</td>
</tr>
<tr>
<td>Highly Complex</td>
<td>Deep Conversion</td>
<td>CDU, HDS, Reforming VDU, FCC, HC, Isomerisation, Alkylation, MTBE, Visbreaking, Coking, Residue conversion or gasification.</td>
</tr>
</tbody>
</table>

*Source: CEG*

The simplest plants only possess atmospheric distillation units and are classified as “topping” refineries. If combined with a catalytic reformer and hydrodesulphurisation unit, they would then be described as “hydroskimming.”

Other important refinery terminology includes:

- **Conversion / Complex**: Include the same constituents as a hydroskimming plant, combined with catalytic cracking;
- **Deep Conversion / Highly Complex**: Refineries that completely convert heavy residues to lighter products. Thus no fuel oil is produced. Many refineries in North America are deep conversion because they use coking units to eliminate all residue. The 2006 Study’s proposed process scheme would be deep conversion because all heavy residues are converted by partial oxidation;
- **Lubes**: Some refineries are specifically designed to process heavy residues into lubricants. Others manufacture waxes and solvents;
- **Bitumen**: Similar to a lube refinery, but instead focused on output of asphalt and related products;
In-Province Upgrading Economics of a Green-field Oil Sands Refinery

- **Partial oxidation**: Hydrocarbons are converted into carbon monoxide-rich syngas. It is a useful route to disposing of heavy residue streams;
- **Petrochemical integration**: Utilises streams from oil refineries (especially light naphtha and certain gases) as feedstock for petrochemical production;
- **Toll processors**: Processes crude oil for third parties. In return for an agreed fee, provides the owners of the crude with a set product yield; and
- **Export refineries**: Designed to export fuel products to multiple countries and/or regions. Such plants are configured to be able to meet a wide range of fuel specifications.

**3.1.4. Other Essential Terminology**

The list below provides definitions of other parameters that are important in understanding the refining industry:

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refining Capacity</td>
<td>The maximum quantity of crude oil that a refinery can process. Usually expressed either as barrels per day or million tonnes per year.</td>
</tr>
<tr>
<td>Refining Throughput</td>
<td>The actual quantity of crude oil processed, again measured in barrels per day or million tonnes per year.</td>
</tr>
<tr>
<td>Utilisation</td>
<td>The extent to which capacity is being utilised, assessed as a percentage of throughput capacity.</td>
</tr>
<tr>
<td>Shutdown</td>
<td>Refers to a planned closure for maintenance work, normally called a “turnaround.”</td>
</tr>
<tr>
<td>Refining Margin</td>
<td>A measure of profitability, expressed as dollars per barrel or per metric tonne of crude.</td>
</tr>
<tr>
<td>Gross Margin</td>
<td>The sum of the value of all products produced from a barrel of oil less the delivered cost of that barrel of oil to the refinery.</td>
</tr>
<tr>
<td>Variable Margin</td>
<td>Gross Margin, less variable operating costs (usually chemicals, additives and utilities).</td>
</tr>
<tr>
<td>Cash Margin</td>
<td>Variable Margin, less fixed costs (typically maintenance and labour).</td>
</tr>
</tbody>
</table>

(Note that it is standard industry practice to exclude depreciation and tax when assessing margins)

**3.1.5. Economics of Refining and Petrochemical Production**

It should be apparent from the preceding paragraphs that refineries can process a wide variety of feedstock using a complex combination of units. Thus unlike most manufacturing operations, it is virtually impossible to know the cost to produce a unit of output from a refinery. This does not pose a problem for the industry, however, because maximising profitability (i.e. margins) is paramount. It is fair to say that refining margins generally depend on combinations of pricing, location and complexity. Locational differences are determined by the cost to deliver product from alternative sources of supply.

Over time, there has been a consistent trend to add ever more complex upgrading units, since they are better placed to deliver sustained profitability over the longer term.

It is worth noting that in unregulated markets there is generally a lag between increased crude oil prices and higher refined product prices. In general therefore, during periods of increasing crude...
prices, low refining margins are to be expected. The opposite trend occurs when oil prices decline; margins normally rise.

In general, refinery margins have improved since the 2008/2011 recession, due to gradual economic recovery in developed countries, especially the United States, augmented by the impact of US shale oil production.

Development of a refinery / petrochemical complex in Western Canada, focused on serving export markets, would not only create employment and economic benefits for Alberta, but would also increase the overall value of Canada’s natural resources, versus exports of crude oil and / or bitumen. It is for similar reasons that some oil exporting countries, such as Saudi Arabia, have developed fuel product export refineries and other downstream industries.

Another important trend is that variable and fixed costs are relatively small, compared to product revenues and feedstock costs. Therefore refiners need to ensure that:

- Gross margins are maximised by selection of an optimal feedstock slate that maximises output of more valuable lighter products, typically to be delivered to neighbouring markets; and
- Fixed and variable costs are minimised.

Not surprisingly refiners need to acquire and process crudes that generate the best margins. These may not always be the cheapest or those which are readily available in the refiners’ local region. To make the selection, refiners work with crude oil traders to utilise highly complex linear programme simulations of refinery operations that help identify relative values of alternative crude mixes (known in the industry as “crude slates”). Other actions that are important to maximising margins are:

- Identify unit-by-unit operating strategies to achieve optimum gross margin. Typically this entails maximising throughput on the main conversion units;
- Optimise product blending, which again requires a linear programme;
- Maintain continuous operations. Unplanned shutdowns are to be avoided. Best practice is to maintain steady and optimal operations between major turnarounds (usually every five years or more);
- Schedule turnarounds carefully to minimise the frequency and duration; and
- Manage inventories carefully within clearly specified and acceptable limits.

The dynamics of the petrochemical industry are much different. In essence, this arises because demand for chemicals is usually highly price elastic. When feedstock prices rise, or economic conditions worsen, demand for chemicals normally declines, thereby lowering consumption of petrochemical feedstock.

Not surprisingly, utilisation rates of petrochemical units are more volatile. Episodes of lower throughput occur when derivative products (e.g. polymers and plastics, etc.) are in surplus, or during recession and periods of high oil prices.
3.1.6. Utilisation and Profitability: Refining and Petrochemicals

It is well known that refinery profitability in recent years has been low. This has arisen for a multitude of reasons, most notably the impact of the global recession on demand for oil-based fuels. Coupled with a shift away from gasoline in developed countries, especially the United States, the result has been closure and/or bankruptcy for many refineries. A good example was European refiner Petroplus, which went into receivership in early 2012.

Nevertheless, financial losses in recent years do not mean that refining is a permanently unattractive industry. As can be seen in Figure 8 below, average utilisation in the economic downturn of 2001/2002 was very similar to 2009/2011, but margins during the latter years have been far worse. This suggests that the differences are due to a complex mixture of factors, among them changes in demand patterns in developed countries (in particular declining gasoline demand and increasing fuel efficiency of motor vehicles, as well as climate change policies to encourage lower consumption).

Thus when poor margins are ascribed, simplistically, to “surplus refinery capacity”, it ignores many other factors such as supply and demand imbalances across the barrel, fluctuations in global oil prices, etc.

A case in point is the sharp improvement in US refining margins since 2012. This is a direct result of two key factors, namely the surge in US production of shale oil, combined with the prohibition on exports of crude oil from the United States27. The export ban has caused crude prices to become disconnected from global markets, since the excess production cannot be shipped elsewhere. This decrease in domestic crude prices has created a profitability boom for US refiners, who have in turn exported fuel products (which are not subject to any export restrictions) to markets elsewhere in the world.

---

27 The ban on US crude exports originated in 1975, when the US Congress passed the Energy Policy and Conservation Act to minimise the impact of future oil embargos by oil producing nations. It was followed by further legislation that gives the President authority to establish rules prohibiting the export of crude oil and natural gas, as well as authority to grant exemptions to the ban under certain circumstances.
Figure 8: Regional Refining Net Margins and Average Utilisation (2000–2013)

![Graph showing regional refining net margins and average utilisation from 2000 to 2013.](image)

Source: EIA, IEA Oil Market Report, BP Statistical Review 2013, CEG & Navigant Consulting analysis

Notes: Net refining margin data for US mid-continent (“US Midcon”) cracking Bakken and “USGC coking HLS/LLS” are only available from May 2012, due to change the in refining margin calculation basis and methodology used in the IEA’s Oil Market Report.

Average refinery utilisation data for 2000 to 2012 from the BP Statistical Review.

Data for 2013 from EIA for US. CEG estimate for EU and Asia Pacific.

Figure 8 also makes it apparent that refineries with coking capability fared much better during the downturn. This is because deep conversion plants eliminate low value heavy fuel oil and maximise production of higher value transport fuels, especially diesel.

As a further example, most complex refineries are configured such that the cracking units reach full capacity before their crude distillation units are fully utilised. Hence, there is generally some spare atmospheric distillation capacity in most North American and West European refineries. Whenever regional topping or hydroskimming margins rise above breakeven on a variable cost basis, complex refineries will increase throughput on their distillation units. As production rises, oversupply will suppress profitability and in turn, refiners will reduce runs and / or shut down distillation units.

Deep conversion refineries, such as proposed for the Project, will on average always have the highest profitability.
3.1.7. The Global Refining Industry

Figure 9: Global Refinery Capacity and Configuration

Figure 9 above shows the capacity of different types of process units in each of the major regions of the world. Although Asia is now the largest, with more plants and the highest distillation capacity, it lags North America in upgrading (i.e. vacuum distillation, catalytic / hydrocracking and coking). The effect of the higher complexity is apparent in Figure 8 above, where net margins at US coking refineries were consistently highest, until the emergence of shale oil.
3.1.8. The Global Petrochemical Industry

Figure 10: Global Ethylene Capacity and Utilisation (2004–2013)

Some of the trends in the petrochemical industry described above are apparent in Figure 10. It shows production and utilisation rates of steam cracking units (used to produce ethylene) in various regions around the world. Output was steadily rising from 2004 through 2008, when global economic growth was strong. But what emerged in 2008, however, due to:

- Crude oil prices reached record levels in mid-2008. This triggered a decline in demand for chemicals and (unusually) for fuel products;
- New ethylene capacity was coming on-stream in the Middle East and Asia, which when combined with the onset of the global recession caused throughput and ethylene production to decline in North America and Europe;
- North America, however, soon countered the utilisation trend, as the availability of cheaper shale gas provided producers in the US and Canada with a significant and sustainable competitive advantage;
- New ethylene production capacity came on-stream in the Middle East. This resulted in higher output but lower utilisation;
- Africa became steadily less competitive for multiple reasons; and
- By the end of 2011 utilisation and throughput began to rise as the global economy recovered.

Source: METI, CEG analysis
3.1.9. Conclusions: Global Trends in Refining and Petrochemicals

Refineries are highly complex manufacturing operations. Their financial results arise from an inter-play of a multitude of factors. It is for this reason that despite the overall downturn in global margins in recent years, certain parts of the industry continued to do well under various conditions, such as inland refiners with captive local markets, or large export plants capable of selling into a variety of end user markets.

A refining and petrochemical complex to process oil sands would allow Alberta to capture enhanced value from its natural resources base. It should be apparent that the factors affecting economic performance of refineries are distinctly different from petrochemicals. The former are driven by the need to maximise margin; in contrast, chemical plants must have the lowest possible costs of production to remain competitive.

Thus in-province processing of oil sands would allow Alberta to capture some of the margin that currently flows to purchasers of its hydrocarbon production elsewhere.
4. Approach

Our approach to assessing the potential economics of the Project was to develop a preliminary high level operating cash flow model, using information set out in the 2006 Study where relevant, and making various additional assumptions.

In our initial discussions on scope with AFL, it was agreed that our assessment would use the same mass balance / yield assumptions as set out in the 2006 Study. However, we have developed our own assumptions around the following areas:

- Supply / demand balance situations for fuel and chemical products in Alberta, Canada, the US and Asia;
- Three constant real crude oil (WTI) price assumptions;
- Fuel product and chemical price forecasts based on each of the three constant real crude oil price scenarios;
- Estimated transportation costs;
- Netback values to Edmonton from USGC benchmark prices where relevant; and
- Estimates of capital and operating cost inflation to be applied to the figures set out in the 2006 Study.

Details of the components of the project and the associated sequence are shown in Figure 11 below.

Figure 11: Structure of analysis and operating cash flow model

Source: CEG
5. **TECHNICAL REVIEW**

5.1. **FEEDSTOCK**

The bitumen being considered as feedstock for the Project would be similar to a Western Canada Select ("WCS") blend – this would be after the oil sands have been mixed with diluent. As illustrated in Figure 12 below, the likes of Hardisty and WCS fall into the low API, high sulphur content group of crudes, which would make their processing more complex, when compared to the lighter sweeter crudes such as Brent or WTI.

**Figure 12: Crude Oil Types – Comparison of API versus Sulphur Content**

In the 2006 Study, Mr Netzer and his team were retained “to develop a conceptual design for an integrated bitumen upgrading, refining and petrochemical complex in Alberta.” This was a challenging task; processing bitumen produced from Canadian oil sands presents many technical complexities. It is high sulphur (>3%), heavy (20 to 25 API°) and many of the output streams would require further processing (severe hydrotreating, etc.) in order to be marketable.

5.2. **TECHNICAL DESIGN**

Given the complexities, the proposed design represents a clever solution that balances many competing constraints, including low feedstock quality, the need to minimise capital cost and meet environmental requirements, while still producing saleable products. Most importantly, since fuels upgraded from coker products are poor quality (i.e. low octane naphtha, low cetane and hydrogen deficient), Mr Netzer has suggested that the coke instead be converted to syngas through partial
oxidation. This would generate hydrogen for use elsewhere in the complex and facilitate ammonia production.

A high level process flow diagram of the 2006 Study’s configuration is shown in Figure 13 below. It uses a combination of catalytic and thermal cracking, together with partial oxidation, to generate both transportation fuels and feedstock for petrochemical production.

Figure 13: Simplified process flow diagram from the 2006 Study

Source: 2006 Study

5.3. **MASS BALANCE**

It was agreed at the outset that our assessment of the likely economic performance of in-province upgrading would use the mass balance from the 2006 Study. As such, we did not consider alternatives or sensitivities based on changes to the proposed feedstock or output configurations.

The mass balance set out in the 2006 Study, and thus the one we have used in our analysis, is presented in Table 8 below.
A key element within the proposed processing plant is that diluted bitumen will be delivered to the complex near Edmonton. Following atmospheric distillation, the diluent (condensate or naphtha-equivalent) will be recycled to oil sands production sites elsewhere in Alberta. It is for this reason that “diluent” appears as both a feedstock and product.

We have assumed in the economic analysis that diluent return streams will be valued at 5% above the price of WTI. We understand this to be relatively standard diluent price for the region, although more recently the price has been 10% above WTI. In our analysis we have taken the more conservative view of WTI plus 5%, given the assessment period of the Project. However, given the current shale oil boom in the US, more recently, there has been a surplus of shale condensates, which has depressed prices in the US, where condensate now sells at a discount to crude oil in the US. It is possible this pressure on pricing may migrate to Canada / Alberta, where condensate is valued at a premium.

It would not be reasonable to use naphtha as alternate value, since oil sands producers could not recover the resultant cost from future sales of “dilbit” (i.e. diluted bitumen).

### Table 8: Project Mass Balance – Integrated Bitumen Processing

<table>
<thead>
<tr>
<th>FEEDSTOCKS</th>
<th>OUTPUTS / PRODUCTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stream</td>
<td>Quantity (ktpa)</td>
</tr>
<tr>
<td>Bitumen diluent</td>
<td>5,628</td>
</tr>
<tr>
<td>Bitumen</td>
<td>16,884</td>
</tr>
<tr>
<td>Coal</td>
<td>700</td>
</tr>
<tr>
<td>Petroleum coke</td>
<td>315</td>
</tr>
<tr>
<td>Isobutane</td>
<td>185</td>
</tr>
<tr>
<td>Ethane</td>
<td>99</td>
</tr>
<tr>
<td>Propane</td>
<td>53</td>
</tr>
<tr>
<td>High sulphur fuel oil</td>
<td>42</td>
</tr>
<tr>
<td>Ammonia</td>
<td>35</td>
</tr>
<tr>
<td>Ammonia syngas</td>
<td>1,050</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>107</td>
</tr>
<tr>
<td>CO2 (enhanced oil recovery)</td>
<td>1,750</td>
</tr>
<tr>
<td>Sulphur</td>
<td>791</td>
</tr>
<tr>
<td>Off gases</td>
<td>8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>23,941</strong></td>
</tr>
</tbody>
</table>

*Source: 2006 Study*
6. **SUPPLY / DEMAND AND PRICING**

6.1. **OVERVIEW**

In order to assess the alternate value of each of the main sales products from the proposed complex in Alberta, it was important to understand the supply / demand balance of each, from both a provincial and all-Canada perspective, as well as different regions. We therefore compiled recent statistics of the net trade balance for fuel and petrochemicals for these areas based on information published by Statistics Canada. In addition, we reviewed the supply / demand balance for the products for the US and certain Asian countries.

We used these balances, combined with a high level understanding of currently planned and projected new plants, to assess whether a particular market is likely to be in surplus or deficit in the short to medium term, and whether the economics of sales into that particular market will be achievable, given the associated transportation costs.

We have not considered the potential impact of barriers to entry in the various regions considered in this report. Although Asia, especially China, may appear to be an attractive destination for some petrochemicals, it may take several years to develop the appropriate marketing channels.

6.2. **CANADA**

6.2.1. **Canada Supply / Demand for Fuel Products**

As shown in Figure 14 and Figure 15 below, most fuel products in Canada and Alberta have recently been either balanced or slightly in surplus. Therefore, as part of our analysis, we considered the capacity, or otherwise, of the US and Asia to accommodate the output from new, incremental production in Alberta. This is because they would be the most obvious targets for incremental output, should Canada / Alberta be in surplus, as they have been recently.
Figure 14: Canadian fuel product supply / demand balances (2012)

Source: Report on Energy Supply and Demand in Canada – 2012 Preliminary; Statistics Canada, CEG analysis

Figure 15: Alberta fuel product supply / demand balances (2012)

Source: Report on Energy Supply and Demand in Canada – 2012 Preliminary; Statistics Canada, CEG analysis
6.2.1. Canada Supply / Demand for Petrochemical Products

Most petrochemicals in Canada are also going to be in surplus as shown in Table 9 below. Hence much of the chemical output will be exported from the Project to rapidly growing markets elsewhere, primarily Asia. We have therefore also assessed the economics of export-based alternate value for all products from the plant.

Table 9: Canadian and Alberta petrochemical supply / demand balance

<table>
<thead>
<tr>
<th>Product</th>
<th>Canadian supply / demand balance</th>
<th>Canadian surplus / (deficit) (ktpa) (i)</th>
<th>Alberta surplus / (deficit) (ktpa) (ii)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Propylene</td>
<td>Surplus</td>
<td>+500 to +600 ktpa</td>
<td>+200 to +500 ktpa 28</td>
</tr>
<tr>
<td>LLDPE</td>
<td>Larger surplus than US</td>
<td>+750 to +1,000 ktpa</td>
<td>n/a</td>
</tr>
<tr>
<td>HDPE</td>
<td>Surplus</td>
<td>+600 to +800 ktpa</td>
<td>+600 ktpa</td>
</tr>
<tr>
<td>LDPE</td>
<td>Balanced</td>
<td>Balanced</td>
<td>+120 ktpa</td>
</tr>
<tr>
<td>Ammonia</td>
<td>Surplus</td>
<td>+1,000 ktpa</td>
<td>+1,200 to +1,400 ktpa</td>
</tr>
<tr>
<td>Methanol</td>
<td>Surplus</td>
<td>+200 ktpa</td>
<td>+85 to +120 ktpa</td>
</tr>
</tbody>
</table>

Source: (i) CEG Europe estimates; (ii) Canadian International Merchandise Trade Database

Figure 16 below shows the supply / demand position for Canada for selected petrochemical products (propylene, benzene, toluene and xylene). The 2012 forecast in Figure 16 below shows the country to have an overall surplus of these products of c. 0.8mtpa, made up primarily of a propylene surplus of c. 0.6mtpa. This overall surplus is expected to continue in the medium term.

28 Williams’ 500 ktpa propane dehydrogenation facility is expected to come on stream in 2016 and will export 100% of polymer grade propylene to the US Gulf Coast.
6.3. US

6.3.1. US Supply / Demand for Fuel Products

One of our economic scenarios assesses the impact of selling the Project’s refined products (gasoline, diesel and aviation kerosene) into the US market. The supply/demand balance in the US for refined products in 2013 is set out in Figure 17 below.

---

29 Combination of propylene, benzene, toluene and xylene.
The chart above shows that the US had an overall supply surplus in 2013 for both gasoline and diesel. In its 2013 *Annual Energy Outlook*, the EIA estimate that, in its reference case, gasoline consumption could decrease by c.18% (or c.70mtpa) by 2040 due to more stringent efficiency and emissions standards. However, the EIA also estimates that diesel consumption could increase by as much as c.27% (c.45 mtpa) due to these more stringent standards.

It is therefore unclear whether there will be sufficient demand in the US to take up all the refined products from the Project.

### 6.3.2. US Supply / Demand for Petrochemical Products

The shale gas boom is transforming certain industries in the US, two of which are petrochemicals and fertilizers. As of 2011, the forecast supply of certain products (propylene, benzene, toluene and xylene combined) started increasing. It is estimated that the forecast net supply surplus of c.5 mtpa in 2012, as shown in Figure 18 below, will gradually increase in the medium term to as much as c.6 mtpa.

Therefore the US should not be seen as a target market for the Project’s petrochemical products.
6.4. **Asia Supply / Demand Balances**

In Mr Osterwald’s Kitimat report, the refined product supply / demand situation for several key Asian economies was analysed, namely China, Japan, South Korea and India. The analysis showed that, despite strong economic growth in some these Asian countries, for about the last 15 years the aggregate demand for fuel product imports has been surprisingly stable at roughly 2 million barrels per day. Thus the fuel product output from Project (c. 0.24 million barrels per day) could be accommodated by markets in Asia without major disruption to local spot markets.

From a petrochemicals viewpoint for certain products, the Asian market has been relatively balanced. Looking at the largest markets historically, deficits in China and India are offset by surpluses in Japan and South Korea. This is illustrated in Figure 19 below.

---

30 Combination of propylene, benzene, toluene and xylene.
However, it should be noted that in its recent report, ‘Global Supply and Demand Trends for Petrochemical Products (for the period from 2004 to 2017)’ the Japanese Ministry of Economy, Trade and Industry forecast that the Asian market will start to be in deficit in the medium term for propylene, toluene and xylene.

Therefore we are of the view that the proposed Project could potentially successfully target several Asian countries. However as we have highlighted in Section 6.1 above, Asian markets are difficult for outsiders to penetrate. Any such venture will require local partnerships.

6.5. CHINA

6.5.1. Chinese Supply / Demand for Fuel Products

The steady growth of the Chinese economy has fuelled a rising demand in refined products and this is illustrated in Figure 20 below.

---

31 Combination of propylene, benzene, toluene and xylene.
32 China, Japan, South Korea and India.
The chart above shows that despite major investment and expansion of refining sector, China’s domestic production has consistently lagged demand, with recent deficits of c.15 mtpa being made up by imports.

Figure 21 below provides more detail and illustrates that net imports correlate closely to China’s growing GDP. It is apparent that China’s imports began to rise sharply from the mid-1990s.
Chinese refining capacity has been expanding dramatically to help meet growing domestic consumption; approximately 1.1 mmbd of distillation capacity was added in the five years between 2008 and 2013. The industry is largely state-owned. One of the Government’s policy objectives is to eliminate many of the small topping and hydroskimming refineries in favour of larger, more complex sites. Thus the Government began to approve foreign investment in Chinese refineries in early 2007. Participants in either operational or planned joint ventures within China include BP, Shell and BASF, Saudi Aramco, ExxonMobil and Qatar Petroleum. Many other companies hope to expand in the country, given the potential opportunities that it presents.

Domestic fuel prices in China are regulated by the central government and price controls have resulted in extensive financial losses by Chinese refiners in recent years. This in turn has encouraged imports of fuel products, although fuel imports are also tightly regulated.

**6.5.3. Chinese Supply / Demand for Petrochemical Products**

The rapid industrialisation and growth of the Chinese economy has also fed increases in demand for petrochemical products. There have been numerous plants coming on-stream in China over the past decade, however this has not been sufficient to meet the country’s growing demand needs. Figure 22 below shows the supply / demand balances for propylene, benzene, toluene and xylene for China for the years 2004 to 2013.
Figure 22: Supply/Demand Balance of Selected Petrochemicals in China (2004–2013)

As Figure 22 above shows, the forecast deficit for the selected petrochemicals products in 2012 was c.6 mtpa and this deficit is expected to continue at just below this level by 2017. Therefore the general predictions are that China will continue to be a net importer of for propylene, benzene, toluene and xylene at least for the medium term, if not longer.

6.6. JAPAN


Figure 23 below shows the steady decline in Japan’s fuel consumption since the late 1990s. This reflects the country’s stagnant / static economy and growth for over a decade. The recent financial crisis has exasperated the country’s economic situation from which it has never fully recovered. Thus Japan resembles the United States more closely than any of the other countries examined for this report.

---

33 Combination of propylene, benzene, toluene and xylene.
Despite these difficulties, Japan still imports consistent volumes of fuel products, which until the recent recession averaged in the region of 50 mtpa. This is illustrated in Figure 24 below.
As a country, Japan’s strategy for many decades has been to encourage domestic refining as a source of product supply, rather than stimulate fuel product imports. The main motivation has been to capture a perceived benefit arising from lower freight costs. Thus product exports are only used to balance the system.

Given the steady decline in Japanese product demand, refinery utilisation has dropped concurrently, despite ongoing efforts at capacity rationalisation. Throughput peaked at 87% in 2005 and has been falling ever since. Japanese refiners ran at 74% of capacity in 2011. It should come as no surprise that Japan is no longer considered a high priority market to some of the major international oil companies. ExxonMobil sold its Japanese downstream subsidiary in 2012 for $3 billion to Japanese refiner and marketer Tonen General Sekiyu.

6.6.3. Japanese Supply and Demand for Petrochemical Products

Japan’s stagnant economy, coupled with the impact of the global financial crisis in 2009 has had the impact of reducing both supply and demand for certain products such as propylene and benzene. Figure 25 below shows the supply / demand balances for propylene, benzene, toluene and xylene for Japan for the years 2004 to 2013.

**Figure 24: Japan Fuel Product Imports and Exports**

![Graph showing Japan Fuel Product Imports and Exports](image)

*Source: EIA*

---

Prepared for Alberta Federation of Labour
The chart above shows that Japan has a net surplus of propylene, benzene, toluene and xylene and is therefore a net exporter. Clearly some of Japan’s exports will target the Chinese market (it is forecast to be in deficit as noted in Section 6.5.3 above) and more generally to Asia (per Section 6.4 above).

6.7. SOUTH KOREA

6.7.1. South Korean Supply and Demand for Fuel Products

Figure 26 below gives an overview of South Korea’s fuel supply / demand balance since 1990. There was a strong growth in consumption, thus demand in the 1990s and although the country’s refiners were expanding at the same time, they were not able keep up until later in the decade, when demand started to stabilise at slightly less than 100 mtpa.

Since then Korean refiners have continued to invest in upgrading projects, so much so that for the last 15 years South Korea has been a net exporter of fuels. This effect was particularly pronounced during the recession in 2008 and 2009.

34 Combination of propylene, benzene, toluene and xylene.
More recently South Korean was a net exporter of a relatively small quantity of surplus fuel production (c.7 mtpa in 2010, per Figure 27 below), it would appear to be more a result of the need to balance the domestic market, rather than a specific export-driven strategy by private refiners.

Source: EIA
6.7.2. The South Korean Refining Industry

The South Korean refining industry is relatively concentrated and is owned entirely by private companies that are predominantly listed on the Korean stock market (all apart from Hyundai). The companies that own the country’s refineries and their distillation capacity are set out in Table 10 below.

Table 10: South Korean Refining Companies and their respective Distillation Capacities

<table>
<thead>
<tr>
<th>Company</th>
<th>Number of Fuel Refineries</th>
<th>Distillation Capacity (barrels/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SK Energy</td>
<td>2</td>
<td>1,115,000</td>
</tr>
<tr>
<td>S-Oil</td>
<td>1</td>
<td>669,000</td>
</tr>
<tr>
<td>GS Caltex</td>
<td>1</td>
<td>775,000</td>
</tr>
<tr>
<td>Hyundai Oil</td>
<td>1</td>
<td>390,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>5</strong></td>
<td><strong>2,949,000</strong></td>
</tr>
</tbody>
</table>

*Source: Oil & Gas Journal, 2013 Worldwide Refinery Survey, Company Annual Reports*

These South Korean companies have invested heavily and approximately $5 billion has been spent on fuel upgrading, petrochemicals and lube expansion projects in the last five years. This effort has been successful, since the South Korean industry is now technically more complex than China, India or Japan.
6.7.3. South Korean Supply and Demand for Petrochemical Products

Coupled with South Korea’s investment in refining expansion, the country has also been expanding its petrochemicals capabilities. Figure 28 below shows the supply / demand balances for propylene, benzene, toluene and xylene for South Korea for the years 2004 to 2013.

Figure 28: Supply/Demand Balance of Selected Petrochemicals\textsuperscript{35} in South Korea (2004–2013)

![Graph showing supply and demand balances for South Korea's petrochemicals from 2004 to 2013.]

\textit{Source}: METI; CEG Analysis

Figure 28 above shows that in 2012 South Korea had a forecast supply surplus of c.3 mtpa of propylene, benzene, toluene and xylene, most of which would be targeted at the Chinese market. In the medium term, this surplus is expected to decrease to c.2.4 mtpa, as domestic demand picks up, with limited increases in production.

6.8. India

6.8.1. Indian Supply and Demand for Fuel Products

The fuels supply / demand balance of India has shifted significantly since the beginning of the economic reform programme in 1991. Prior to that time the country’s strategy was to endeavour to be “self-sufficient.” As reforms took hold, however, fuel demand began to increase, which was partially met by higher levels of imports, as shown in Figure 29 below.

\textsuperscript{35} Combination of propylene, benzene, toluene and xylene.
An essential distinction between India and China that should be emphasised is ownership of the refining industry. Although much of the latter is state-owned, a few large multi-national companies have managed to participate in joint ventures with such companies as Sinopec and CNPC.

India is radically different; in the early 1990s most of the sector was owned by Indian Public Sector Undertakings (“PSUs”), such as Indian Oil, Hindustan Petroleum, Bharat Petroleum and others. Over the last decade however, activity by privately-held refineries has risen sharply as seen by the increase in distillation capacity by over 60% since 2007, shown in Table 11 below.

Table 11: Ownership of Indian Refineries

<table>
<thead>
<tr>
<th>Refineries</th>
<th>Distillation capacity (Mtpa)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2007</td>
</tr>
<tr>
<td>PSUs</td>
<td>105.5</td>
</tr>
<tr>
<td>Joint venture / private</td>
<td>43.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>149.0</td>
</tr>
</tbody>
</table>

Source: Ministry of Petroleum and Natural Gas, Petroleum Planning and Analysis Cell

Private Indian refiners have increased domestic production sharply, since one of their objectives has been to supply products to other Asian markets. This export-driven strategy is motivated in
part by Indian price controls, which tend to limit refining margins. The results are clearly demonstrated in Figure 30. Since 2000, net product exports have gone from nearly zero to just under 50 mtpa. We do not believe that China is likely to follow suit, given that most of the refining sector remains predominantly state-owned.

**Figure 30: India Fuel Product Imports and Exports**

![India Fuel Product Imports and Exports](chart)

*Source: EIA*

### 6.8.3. Indian Supply and Demand for Petrochemical Products

India has a relatively small appetite for the selected petrochemical products under review. Domestic demand was in the region of 5 mtpa in 2012 as illustrated in Figure 31 below which shows the demand / supply balances for propylene, benzene, toluene and xylene for India for the years 2004 to 2013.
Although Figure 31 above shows that in 2012 India was forecast to be in net surplus, in the medium term it is expected to have a deficit of propylene and toluene.

6.9. CONCLUSIONS

From our review of the regional supply / demand balances, we believe that fuels will be marketable in Canada, the US and Asia. Petrochemicals are somewhat different. It is apparent that North America will be in surplus for the foreseeable future, thus the most likely destination for petrochemicals for the next few years will be China. But as an export-focused plant, the objective will be to sell to maximise margins by selling to markets that provide the highest netbacks. This will change over time and will not always be China.

---

36 Combination of propylene, benzene, toluene and xylene.
7. **ECONOMICS OF IN-PROVINCE UPGRADING OF OIL SANDS**

7.1. **INTRODUCTION**

In order to assess the potential economics of the Project we have developed an operating cash flow model. This allowed us to derive a high level indicative enterprise value range of the bitumen processing complex, under various assumptions and scenarios. The indicative valuation reflects a pre-financing assessment of the Project.

In preparing the indicative enterprise value we used a discounted cash flow methodology. This uses a projected stream of future cash flows, which are then given a current value by discounting the stream of future cash flows back to the point in time at which the valuation is to be made. The discounting process recognises the “time value of money” and therefore more distant cash flows are valued less highly than those received earlier.

We have developed the model of the Project based on a 30 year period from 2014 to 2043. This assumes construction would start in 2014 with commissioning starting in 2018, being fully operational by 2021. The information used in developing the model has come from a number of sources:

- Information contained in the 2006 Study;
- Information supplied by the Alberta Department of Labour;
- Navigant / CEG Europe assumptions for those areas where there lacked detailed information; and
- CEG Europe pricing assumptions.

The model derives a 30 year operating cash flow from 2014 to 2043. We have discounted the cash flows from 2014 to 2043, based on the scope set out in the 2006 Study, and added a terminal value in 2044 (based on an EBITDA multiple) to give a net present enterprise value for the Project. The Base Case assumptions that have been used are set out on the following pages.

7.2. **FEEDSTOCK PRICES**

7.2.1. **Crude Oil**

It has been assumed that the feedstock will be an oil sands / bitumen and diluent blend (in a ratio of 3 to 1 as detailed in the mass balance in the 2006 Study). The bitumen diluent blend is comparable to Western Canada Select, a heavy crude oil with an API gravity between 19 and 22.

We have used three WTI crude oil price scenarios for our pricing projections in the development of the estimated enterprise value of the Project. The WTI prices are $80, $100 and $120 per barrel, on a constant real 2013 basis. At present we understand that much of the oil industry is using an average of around $100/barrel for medium to long term assessments and decision making.
In-Province Upgrading Economics of a Green-field Oil Sands Refinery

Our normal pricing methodology uses a flat real crude price due to the inherent uncertainty of how crude prices will actually fluctuate in both the short and long term. This was demonstrated at the start of the recession in 2008 and subsequent years. In mid-2008, crude prices attained unprecedented levels in excess of $130/barrel, but then dropped sharply to lows of around $35/barrel, albeit for a relatively short period of time at the height of the crisis in 2008 / 2009. By late 2010/2011, prices were back in the $90/barrel to $100/barrel range.

Western Canada Select has historically had a close correlation with WTI. We have therefore used this historical correlation to derive the related feedstock price under each crude scenario.

7.2.2. Natural Gas

Certain items that are either used or produced by the plant, such as ethane (feedstock) and propylene (petrochemical feedstock) have a closer pricing relationship to natural gas rather than crude oil. For our economic assessment we have used a single Henry Hub (“HH”) natural gas scenario with a constant real price of $5/mmbtu. This is based on the average of the EIA recent “reference case” outlook and our understanding from discussions with those in the industry who are assessing long term natural gas based projects in North America.

7.2.3. Pricing Methodology

Our outlook for future fuel and chemical prices was derived from historic correlations between crude oil prices and refining margins. The correlation is driven by inelastic demand for fuels, unless very high crude prices are attained, which we assume, for a medium or long term forecast, will not be sustainable. The dampening impact of very high crude prices on fuel demand was demonstrated in 2008. It should be noted, however, that the methodology we have employed has not attempted to incorporate the impacts of:

- Supply and demand of oil products within and between various regions;
- The outlook for changes in capacity within and between regions; and
- Trade patterns.

7.3. Refining Margins

Over much of the history of the oil industry there has been a strong correlation between the level of crude oil prices and refining margins. This relationship was used in our projections to derive forecasts of gross refining margins at various crude prices. It was based on actual results for 2000 through 2008.

It should be noted that we excluded the years 2009 through 2011 from our analysis because the global recession caused a major market dislocation and traditional relationships between crude oil, fuel products and natural gas were disrupted but have now recovered in some markets.

A series of fuel price forecasts was generated based on the crude oil prices and refining margin assumptions set out in Table 12 below:
Table 12: Assumptions for developing refining margins

<table>
<thead>
<tr>
<th>WTI $(/barrel)</th>
<th>USGC Mars / Maya Coking Margin $(/barrel)</th>
</tr>
</thead>
<tbody>
<tr>
<td>80</td>
<td>19.9</td>
</tr>
<tr>
<td>100</td>
<td>22.2</td>
</tr>
<tr>
<td>120</td>
<td>24.1</td>
</tr>
</tbody>
</table>

Source: CEG analysis

The refining margins were derived using a typical benchmark refinery configuration and yield for an USGC coking complex, with a relatively heavy and sour feedstock (i.e. Mars / Mayan blend). This type of plant would be the closest benchmark in the public domain that can be used to derive potential margins for the proposed Project. The forecast refining margins and in turn fuel prices, were split between the refinery products based on their relative yields.

Once the fuel price forecasts were generated, a set of consistent petrochemical price projections were also produced. Again each of the main petrochemical products was correlated with their base feedstock that would drive their pricing. Each considered the impact of crude oil price on chemical demand, economic growth, etc.

7.4. BASE CASE RESULTS

The Base Case indicative value for the Project under the three crude oil price scenarios is set out in Table 13 below. The key assumptions for the Base Case are set out in the following section.

Table 13: Indicative Base Case Results

<table>
<thead>
<tr>
<th>WTI Price</th>
<th>NPV @ 8.9% real</th>
<th>IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>$80</td>
<td>$12.1 billion</td>
<td>19.0%</td>
</tr>
<tr>
<td>$100</td>
<td>$17.5 billion</td>
<td>22.6%</td>
</tr>
<tr>
<td>$120</td>
<td>$22.8 billion</td>
<td>25.6%</td>
</tr>
</tbody>
</table>

Source: CEG

Based on existing capital cost estimates and arms-length purchase of feedstock at market prices, the Project is appears to be attractive, with NPV and IRR, showing relatively good returns.

7.5. ASSUMPTIONS

7.5.1. General

The cash flow model has been developed on a real term (2013) basis, using an 8.9% real discount rate with NPVs discounted to the end of 2013. The indicative valuations presented in this section represent the enterprise value of the whole project from 2013.

Table 14 below sets out the key Base Case assumptions for the enterprise valuation.

---

37 For an archetype USGC cracking / coking refinery processing a blend of Mars and Maya.
Table 14: Base Case Assumptions

<table>
<thead>
<tr>
<th>Area</th>
<th>Base Case Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pricing (sales and feedstock)</td>
<td>Based on CEG Europe price set, derived from WTI crude at the following three constant real price levels:</td>
</tr>
<tr>
<td></td>
<td>• $80 / barrel</td>
</tr>
<tr>
<td></td>
<td>• $100 / barrel</td>
</tr>
<tr>
<td></td>
<td>• $120 / barrel</td>
</tr>
<tr>
<td></td>
<td>The bitumen/diluent feedstock is assumed to be similar to Western Canada Select which has been used as the feedstock price – this has been correlated to WTI. The return stream of diluent has been priced at WTI plus 5%.</td>
</tr>
<tr>
<td></td>
<td>We have not assumed a petrochemical price cycle.</td>
</tr>
<tr>
<td>Construction Phase</td>
<td>Based on the Expenditure Curve set out in the 2006 Study, which is as follows:</td>
</tr>
<tr>
<td></td>
<td>• Year 1 – 2014 2%</td>
</tr>
<tr>
<td></td>
<td>• Year 2 – 2015 13%</td>
</tr>
<tr>
<td></td>
<td>• Year 4 – 2016 35%</td>
</tr>
<tr>
<td></td>
<td>• Year 5 – 2017 30%</td>
</tr>
<tr>
<td></td>
<td>• Year 6 – 2018 13%</td>
</tr>
<tr>
<td></td>
<td>• Year 7 – 2019 7%</td>
</tr>
<tr>
<td>Ramp up</td>
<td>The ramp-up over four years set out below and is based on our experience with other plants of this nature.</td>
</tr>
<tr>
<td></td>
<td>Starting in 2018, we assume a ramp-up as follows:</td>
</tr>
<tr>
<td></td>
<td>• 2018 at 10%</td>
</tr>
<tr>
<td></td>
<td>• 2019 at 50%</td>
</tr>
<tr>
<td></td>
<td>• 2020 at 90%</td>
</tr>
<tr>
<td></td>
<td>• 100% by 2021</td>
</tr>
<tr>
<td>Operating Rates</td>
<td>The 2006 Study states that the plant configuration is based on 350 stream days of the calendar year.</td>
</tr>
<tr>
<td></td>
<td>Based on our experience, however, a plant will never actually operate for the full number of stream days over the long term given major turnarounds and minor repair schedules. We believe that 330 days of operation for the plant is a more reasonable expectation.</td>
</tr>
<tr>
<td>Capital costs</td>
<td>Capital costs assumed to be $10.2 billion, based on CEG’s adjustments to the 2006 Study, as set out in Section 7.5.2 below.</td>
</tr>
<tr>
<td></td>
<td>In addition, we have included additional ‘stay in business capex.’ It is based on 0.50% per year of ISBL and OSBL capital costs, starting in year 3 of operation.</td>
</tr>
<tr>
<td>Variable costs</td>
<td>This was a very high level estimate and mainly represents processing costs (i.e. chemicals and catalysts) based on our estimates.</td>
</tr>
<tr>
<td></td>
<td>Variable costs will need to be assessed in more detail at a later stage.</td>
</tr>
<tr>
<td>Fixed Costs</td>
<td>Represents labour costs, insurance and taxes and maintenance. Figures for the first two items were set out in the 2006 Study.</td>
</tr>
<tr>
<td></td>
<td>We have used the insurance and taxes figure from the 2006 Study and escalated it at 3% p.a. to arrive at a 2013 rebased cost.</td>
</tr>
<tr>
<td></td>
<td>For labour, we rebased the 2006 figure using labour cost inflation rates in Canada from 2007 to 2013 of c.4.1% p.a. As a result, labour costs increased from US$ 200 million p.a. in 2006 to US$ 266 million p.a. in 2013.</td>
</tr>
<tr>
<td></td>
<td>Based on average salary costs of c. $100,000 p.a., however, this would imply a labour force of around 2,500, which we believe to be very high.</td>
</tr>
<tr>
<td></td>
<td>Using benchmark staffing information derived from North America, a more reasonable estimate of the workforce for this plant would be in the region of 1,000 employees, which would also include maintenance staff. Using the average salary costs of c. $100,000, the labour cost would be approximately US$ 100 million p.a.</td>
</tr>
<tr>
<td></td>
<td>We have also included maintenance costs of 1% p.a. of the replacement cost of the plant.</td>
</tr>
</tbody>
</table>
|      | No further fixed costs have been included and clearly these would need to be properly assessed in
more detail at a later stage.

**Project Tax rates**
Assumed a combined federal / provincial corporate income tax rate of 25%.

**Depreciation**
Straight line for 20 years.

**Working capital**
The 2006 Study sets out certain basis on which working capital items are derived, however, there does not appear to be full transparency around how the working capital amounts are calculated. We have attempted to replicate the relative working capital levels from the 2006 Study and have assumed the following:

- Feedstock inventory: 5 days production
- Product stock: 5 days production
- Debtor days: 10 days sales
- Creditor days: 0 days purchases

**Cash flow basis / Inflation**
The cash flow model has been developed on a real basis. Given the ongoing tight labour market in the industry in North America, we have assumed real wage inflation of 1% per annum.

**Discount Rate / Cost of Equity**
We have used a real cost of capital (assuming 100% equity at this stage) for this project of 8.9%. Details of the calculation of WACC are set out in more detail below.

**Cash flow timeline and Terminal Value (TV)**
The model has estimated cash flows for the Project from 2014 to 2043. In 2044, a terminal value has been estimated based on the Project’s EBITDA in 2043. An average Enterprise Value / EBITDA multiple of 4.57 has been used. This is based on the current average Enterprise Value / EBITDA of quoted North American companies which focus mainly on refining or downstream operations. The benchmark companies used are Tesoro, Valero, Phillips 66 and Marathon Petroleum.

**Sales**
The Base Case assumes all products are sold into the local market, given the inland location of the complex. We have also run some sensitivities which we set out in Section 7.7 below on assumed sales into alternative markets.

Source: CEG

### 7.5.2. Capital Costs
Table 15 below sets out the breakdown of the Project’s capital costs.
### Table 15: Breakdown of Construction Costs (US$ billion)

<table>
<thead>
<tr>
<th>Category</th>
<th>Base Estimate Cost</th>
<th>Contingency</th>
<th>Total Cost</th>
<th>2007 to 2013 Escalation (3% p.a.)</th>
<th>Total 2013 Cost</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISBL</td>
<td>3.18</td>
<td>1.27</td>
<td>4.45</td>
<td>1.17</td>
<td>5.62</td>
<td></td>
</tr>
<tr>
<td>OSBL</td>
<td>1.84</td>
<td>0.73</td>
<td>2.09</td>
<td>0.55</td>
<td>2.63</td>
<td></td>
</tr>
<tr>
<td><strong>Total Plant</strong></td>
<td></td>
<td></td>
<td><strong>6.54</strong></td>
<td></td>
<td><strong>8.25</strong></td>
<td></td>
</tr>
<tr>
<td>Edmonton Location Factor Uplift</td>
<td></td>
<td></td>
<td>0.78</td>
<td></td>
<td>0.99</td>
<td>Note 1</td>
</tr>
<tr>
<td><strong>Total Plant at Edmonton</strong></td>
<td></td>
<td></td>
<td><strong>7.32</strong></td>
<td></td>
<td><strong>9.24</strong></td>
<td></td>
</tr>
<tr>
<td>License Fees</td>
<td>0.10</td>
<td></td>
<td>0.28</td>
<td></td>
<td></td>
<td>Note 2</td>
</tr>
<tr>
<td>Land Costs</td>
<td>0.01</td>
<td>0.00</td>
<td>0.01</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Owners Costs</td>
<td>0.20</td>
<td></td>
<td>0.66</td>
<td></td>
<td></td>
<td>Note 3</td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td></td>
<td></td>
<td><strong>7.63</strong></td>
<td></td>
<td><strong>10.19</strong></td>
<td></td>
</tr>
<tr>
<td>Escalation during construction</td>
<td></td>
<td></td>
<td>1.46</td>
<td>n/a</td>
<td></td>
<td>Note 4</td>
</tr>
<tr>
<td><strong>Total construction costs</strong></td>
<td></td>
<td></td>
<td><strong>9.09</strong></td>
<td></td>
<td><strong>10.03</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: CEG analysis

**Note 1:** The 2006 Study assumed a location factor uplift of approximately 12%. We believe that given the potential pipeline of major project currently being scheduled in North America, 12% may be too low, as there will be significant demand for resources in the medium term. We propose that a sensitivity is run to assess the potential impact of a higher location factor uplift (say 30%).

**Note 2:** The 2006 Study assumes licence fees of $95 million. We have assumed instead that such fees would be 3% of ISBL & OSBL costs.

**Note 3:** The 2006 Study assumed Owners Costs of US$200 million (c.3% of ISBL & OSBL costs). Based on our experience of project of a similar nature, Owners Costs are usually in region of 7% to 14% of the ISBL & OSBL costs. For this project we have assumed Owners Costs of 8% of ISBL & OSBL.

**Note 4:** The 2006 Study applied a 5% compounded annual escalation for each year of project execution for capital costs not yet incurred. It is our view this is double counting to an extent, as project contingencies are already included. In addition, we believe that the owner would take necessary steps to ensure that all contractors are tied in to an extent which would not allow for significant escalation during construction.

### 7.5.3. WACC

We have estimated the weighted average cost of capital for the project to 8.9%. Details of how the WACC was calculated are set out in Table 16 below.
### Table 16: WACC Calculation

<table>
<thead>
<tr>
<th></th>
<th>%</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>US Risk Free Rate (30 year government bonds)</td>
<td>3.7%</td>
<td></td>
</tr>
<tr>
<td>Canada Risk Premium</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>Adjusted Risk Free Rate</td>
<td>3.7%</td>
<td>Based on similar North American companies in refining/downstream</td>
</tr>
<tr>
<td>Beta</td>
<td>1.2</td>
<td>Based on historical average</td>
</tr>
<tr>
<td>Equity Risk Premium</td>
<td>5.8%</td>
<td></td>
</tr>
<tr>
<td>Cost of Equity (nominal)</td>
<td>10.8%</td>
<td></td>
</tr>
<tr>
<td>US Risk Free Rate (30 year government bonds)</td>
<td>3.7%</td>
<td></td>
</tr>
<tr>
<td>Borrowing Premium</td>
<td>n/a</td>
<td>Not considered at this stage</td>
</tr>
<tr>
<td>Pre-Tax Cost of Debt</td>
<td>n/a</td>
<td>Not considered at this stage</td>
</tr>
<tr>
<td>Tax Shield</td>
<td>25%</td>
<td></td>
</tr>
<tr>
<td>After-Tax Cost of Debt</td>
<td>n/a</td>
<td>Not considered at this stage</td>
</tr>
<tr>
<td>Nominal WACC (assuming equity to debt ratio of 100%: 0%)</td>
<td>10.8%</td>
<td></td>
</tr>
<tr>
<td>US Risk Free Rate (10 year government bonds)</td>
<td>1.7%</td>
<td>Estimated inflation rate based on 30-year US Treasury inflation-protected securities</td>
</tr>
<tr>
<td>Real WACC (assuming equity to debt ratio of 100%: 0%)</td>
<td>8.9%</td>
<td></td>
</tr>
</tbody>
</table>

Source: CEG analysis

### 7.6. Risk Factors

The discounted cash flow valuation method that we have used to generate the indicative values is subject to a range of limitations, which represent the risk factors involved in the valuation of a business or enterprise. These factors are:

- **Macroeconomic**: changes in world and local markets affect the economics of refining and petrochemicals plants;
- **Political**: government opinion and policy can have a serious impact on a company’s value;
- **Regulatory**: the discounted cash flow model assumes that markets will continue in their deregulated state; and
- **Microeconomic**: the structure and method of operation of the Company in the future.

The indicative valuations presented in this report may vary significantly in response to a wide range of these internal and external risk factors.

---

38 Tesoro, Valero, Phillips 66 and Marathon Petroleum.
7.7. **SALES INTO ALTERNATIVE MARKETS**

Given the supply / demand balance of fuels and petrochemicals in Alberta, we were asked to assess the potential impact on the viability of the Project of exporting its production into alternative markets. This has required estimates of transportation costs for refined and petrochemical products from Alberta to three locations, these being USGC, Canada (as a whole) and Asia.

The estimates of transportation costs to / from Alberta were based either on current pricing differentials reflected in the netbacks or our estimates based on publicly available information, adjusted for the relevant destinations:

**Table 17: Assumed Transportation Costs from Alberta ($/ton or as a percentage of price)**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Alberta</th>
<th>Canada</th>
<th>US</th>
<th>Asia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Products</td>
<td>–</td>
<td>$90-$120(^{39})</td>
<td>9.0%-9.5%</td>
<td>$68-$96(^{40})</td>
</tr>
<tr>
<td>Petrochemicals</td>
<td>–</td>
<td>$75-$96(^{41})</td>
<td>$105-$140(^{42})</td>
<td>$120-$174</td>
</tr>
</tbody>
</table>

*Source: CEG analysis*

It should be noted that we have assumed that ethylene will always be consumed locally in Alberta. It would be purchased by a local plant at a discount to the netback price, given the difficulty in shipping this product long distances without a pipeline. Our assumption is that a discount of approximately $400 per ton would be applicable.

The scenarios we have used are as follows:

**Table 18: Scenarios for Destination Markets for Output from Plant**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Alberta</th>
<th>Canada</th>
<th>US</th>
<th>Asia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>Fuel Products ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Petrochemicals ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>Fuel Products ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Petrochemicals ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.</td>
<td>Fuel Products ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Petrochemicals ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.</td>
<td>Fuel Products ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Petrochemicals ✓</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Source: AFL & CEG*

\(^{39}\) Assumess rail freight to Eastern Canada, distance of c.3,200 miles.

\(^{40}\) Assumes rail freight from Alberta to Vancouver (c.1,100 miles) plus marine freight from Vancouver to South East Asia.

\(^{41}\) Assumes marine freight (barge) from USGC to Eastern Canada; less rail from Alberta.

\(^{42}\) Assumes rail freight USGC to Alberta (c.3,700 miles).
The results of the Base Case and Scenarios 1 to 3, under our three crude oil price sets are set out in Table 19 below.

### Table 19: Results of Alternative Destination Markets

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$80/bbl NPV ($ billion)</th>
<th>$80/bbl IRR (%)</th>
<th>$100/bbl NPV ($ billion)</th>
<th>$100/bbl IRR (%)</th>
<th>$120/bbl NPV ($ billion)</th>
<th>$120/bbl IRR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>12.1</td>
<td>19.0%</td>
<td>17.5</td>
<td>22.6%</td>
<td>22.8</td>
<td>25.6%</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>7.8</td>
<td>15.9%</td>
<td>12.6</td>
<td>19.3%</td>
<td>17.1</td>
<td>22.2%</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>8.3</td>
<td>16.2%</td>
<td>12.8</td>
<td>19.4%</td>
<td>17.0</td>
<td>22.2%</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>7.8</td>
<td>15.9%</td>
<td>12.5</td>
<td>19.2%</td>
<td>16.8</td>
<td>22.0%</td>
</tr>
</tbody>
</table>

Source: CEG analysis

Given its inland location and the potential transportation costs required for alternative markets, it appears that the plant is best suited to supply local areas, should there be sufficient demand.

However, based on the current supply / demand outlook for Canada and the US, both markets are likely to be in surplus. Table 19 above shows that Scenario 3, which looks at supplying product into the Asian market, still shows reasonable returns under all the crude pricing scenarios, despite the logistics involved.

### 7.8. Sensitivity Analysis

There are numerous variables and assumptions that can have an impact on the potential value of the Project. At this stage, however, there are two key items whose variation can have a significant impact on the economic viability of the Project. We consider below:

- **Bitumen feedstock price:** We understand that as the resource owner, the Government of Alberta is entitled to take its royalty share of bitumen production as physical barrels rather than in cash payments. Therefore there may be potential for the plant to receive a discounted price on the bitumen it purchases. Small reductions in the bitumen price have a favourable impact on economics Project.

- **Capital costs & Edmonton location factor:** As noted above there may be resource constraints (e.g., engineering, labour, etc.) in North America affecting construction of such a plant. Thus a 12% location uplift against USGC could be inadequate (see below). We therefore considered an uplift of 30% as a sensitivity.

- **Diluent return stream price:** As noted in Section 5.3 above, there may be a possibility that the price of condensate in Canada also comes under pressure, akin to the US and starts trading at a discount to crude oil. We have therefore considered, at a very high level, the impact of the diluent return stream being priced at a 15% discount to WTI rather than a 5% premium.

#### 7.8.1. Sensitivity Analysis Results

The results of the Base Case sensitivity analysis are set out below.
Bitumen feedstock price

Table 20 below sets out the respective impacts of a 10% and 20% discount on the bitumen feedstock price. Such a discount has a significant effect on the Project and could make it a much more viable proposition.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$80/bbl</th>
<th>$100/bbl</th>
<th>$120/bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NPV ($ billion)</td>
<td>IRR (%)</td>
<td>NPV ($ billion)</td>
</tr>
<tr>
<td>Base Case</td>
<td>12.1</td>
<td>19.0%</td>
<td>17.5</td>
</tr>
<tr>
<td>10% Discount</td>
<td>17.3</td>
<td>22.5%</td>
<td>24.2</td>
</tr>
<tr>
<td>20% Discount</td>
<td>22.5</td>
<td>25.7%</td>
<td>30.8</td>
</tr>
</tbody>
</table>

Source: CEG analysis

Table 20 above shows that a modest price discount of 10% increases NPV by between $5 billion to $8 billion, depending on the crude oil price scenario, with a corresponding uplift in IRR of between 3.5% to 4.4%.

The Government of Alberta has the flexibility to adjust the cost of oil sands to users (through the Bitumen Royalty in Kind). Discounts on feedstock prices could be used, if necessary, to improve returns, should there be cost increases in other risk areas (e.g. capital costs, etc.).

Capital costs & Edmonton location factor uplift

There are numerous petrochemical projects under consideration in North America and depending on the number of plants that are actually commissioned, the labour and materials market may not have sufficient capacity to meet all demand, without significant upward pressure on construction prices. On the costs side, this is further exacerbated by construction slowdowns in Alberta during the winter periods.

In a recent studies (Profitability of Petrochemical Plants In Alberta Industrial Heartland vs. Gulf Coast; Stantec Consulting Ltd.; February 2013) it was estimated that currently downstream plants in Alberta had a location factor uplift of approximately 20% over the US Gulf Coast.

For our sensitivity analysis, given the potential for a very tight construction market in North America in the medium term, we have run the possible impact on the Project economics from an increase in the location factor from 12% to 30%. This equates to a 15% overall increase in the capital cost of the project from $10.2 billion to $11.7 billion.
In Province Upgrading Economics of a Green-field Oil Sands Refinery

Table 21: Impact of Edmonton location factor uplift increase from 12% to 30%

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$80/bbl</th>
<th></th>
<th>$100/bbl</th>
<th></th>
<th>$120/bbl</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NPV ($ billion)</td>
<td>IRR</td>
<td>NPV ($ billion)</td>
<td>IRR</td>
<td>NPV ($ billion)</td>
<td>IRR</td>
</tr>
<tr>
<td>Base Case</td>
<td>12.1</td>
<td>19.0%</td>
<td>17.5</td>
<td>22.6%</td>
<td>22.8</td>
<td>25.6%</td>
</tr>
<tr>
<td>15% Capex increase</td>
<td>10.9</td>
<td>17.2%</td>
<td>16.4</td>
<td>20.5%</td>
<td>21.7</td>
<td>23.4%</td>
</tr>
</tbody>
</table>

Source: CEG analysis

The table shows that a 15% increase in capital costs reduces NPV by c. $1.1 billion under all three crude oil pricing scenarios, with IRR decreasing by between 1.8% and 2.2%.

Diluent return stream price

If the price of condensate trades at a 15% discount to WTI, under the Base Case, NPV is likely to decrease in the region of $3.5 billion to $5 billion under all three crude oil pricing scenarios, with a corresponding reduction in IRR of between 2.5% and 3.0%.

7.8.1. Comparison of CEG’s results with other reports

Alberta’s Advantage

Recent analysis by Stantec Consulting\(^{43}\) shows Alberta having operations and engineering labour cost advantages over the US Gulf Coast. Although construction costs are higher in Alberta’s Industrial Heartland due to, among other factors, availability of skilled labour and winter costs, these are more than offset by other significant advantages, namely:

- More advantageous corporate tax rates – Alberta and Canada’s effective corporate tax rate is 25% compared to 43% on the US Gulf Coast.
- Cheaper operations labour in Alberta – Effective wages are 5% lower and payroll burdens are 11% less in Alberta when compared to the US Gulf Coast.
- Feedstock, power and natural gas are cheaper in Alberta than in the US Gulf Coast.

One of the key findings from the Stantec Consulting analysis was the following:

“Chief among our findings is the conclusion that there is no distinctive financial advantage to siting a methanol plant in the Gulf Coast (CG) compared to the Alberta Industrial Heartland (AIH) as shown in the table below. Both the AIH and GC options produce a result that is significantly better than siting a Methanol plant in Regional Municipality of Wood Buffalo (RMWB)”.

This study appears to reinforce our view that building a refinery/petrochemical/chemical plant in Alberta, close to cheap and abundant feedstock should be no less attractive that one on the US Gulf Coast.

---

\(^{43}\) Profitability of Petrochemical Plants in Alberta Industrial Heartland vs. Gulf Coast; Stantec Consulting Ltd., February 2013. The study assessed the potential financial implications of constructing an identical methanol plant in each of the following three locations: US Gulf Coast, the Alberta Industrial Heartland and the Regional Municipality of Wood Buffalo (Fort McMurray, Alberta).
8. CONCLUSIONS

Our analysis of the economics of an in-province upgrading refinery and petrochemical complex in Alberta suggests that it is likely to be profitable and generate favourable economic returns. So much so, in fact, that it would meet many of the criteria necessary to attract investment from the private sector. There are several factors that work in the project’s favour, including:

- Mr Netzer’s configuration uses partial oxidation to eliminate heavy residues and reduce the amount of hydro-processing of fuel products derived from oil sands;
- The market value of oil sands at Hardesty is quite low; return diluent streams are valued at higher naphtha-related alternate value; and
- The complex would have the capability to maximise margins by selling into a variety of end-user markets (i.e. Alberta, Canada, the US and Asia), as necessary to optimise profitability.

On the basis that this project is commercially attractive and viable, the onus is likely to be on the Government of Alberta to move it forward, at the initial stages at the very least. The Government could act as the conduit or aggregator of feedstock that could sell the bitumen to local upgrading plants. Incentive mechanisms already in place may be used to allow the Government to do this.

Furthermore, incentives, such as discounted feedstock prices may be used to encourage the private sector to assume a greater role in development of the Project. Alternatively, the Government may have to initiate the process on its own or through a partnership with the private sector. Although there may be an initial cost to these incentives, over the medium to long term it is likely to benefit the Province, both in financial and non-financial terms (such as job creation and less dependency on the upstream sector).

Given these favourable economics, it is perhaps surprising that the private sector has, to date, not taken a greater interest in such a project. There are many factors at work, such as:

- Much of the existing oil sands production has been processed in existing refining capacity, both in Canada and the US; and
- Likewise, to date there has been sufficient pipeline capacity to deliver oil sands to consumers. As output in Alberta continues to increase, however, the capability to deliver to buyers outside the Province may become constrained (e.g. if the Keystone and / or Trans Canada pipelines are not constructed), in which case the Project would assume greater importance to both Alberta and Canada as well.
- Until recently, refining margins in North America were quite low. The international integrated companies have been scaling back downstream operations and focusing on the upstream sector. Similarly smaller midsize companies have been focusing on consolidating existing assets through acquisitions and restructuring.
The emergence of shale oil production in the US, beginning in 2012, created a steadily rising surplus of crude oil that under current law cannot be exported. This has caused crude prices in the US to drop sharply, so much so that they are disconnected from world oil markets. In turn, there has been a surge in refining profitability.

Our analysis of in-province upgrading of Canadian oil sands shows a similar pattern. Surplus production in Alberta may become increasingly difficult to export, so the value of oil sands output in the Province will decline. This will, in much the same way as refining in the US, cause the profitability of upgrading to improve.

It may be appropriate for Government, through the use of appropriate incentives and/or joint venture partners, to take a prominent role in encouraging investment in oil sands upgrading. The objective would be to sell finished products into a variety of export markets, as required to maximise margins at the upgrading complex in Alberta.