

Adding Value to Alberta's Oil Sands

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Abstract

A rapidly expanding oil sands industry and a dwindling supply of feedstock for Alberta's ethane-based petrochemical industry have stimulated interest in evaluating bitumen for producing a broad slate of refined products, including petrochemicals. Two industry/government studies evaluated different process schemes for integrating oil sands, refining, and petrochemical operations and convert heavy gas oils into both refined products and petrochemicals. Since market demand for fuels and refined products far exceeds that for petrochemicals, the performance characteristics of the heavy oil conversion processes are important to optimize the volume ratios of the products to meet market volume demands. The paper reviews different heavy oil processing technologies focusing on olefin to fuel product ratios and flexibility to change these ratios. The review includes conventional non-catalytic thermal (steam) cracking, as well as catalytic processes. These technologies are at different stages of commercial development for production of fuels and olefins, and must be evaluated and adapted to meet Alberta's aromatic bitumen-derived heavy gas oils. Work is underway in an industry/government study towards developing an integrated process for the combined production of refined fuels and petrochemical feedstocks. In addition, two workshops were held in February 2005 to address the business and regulatory gaps that needed to be addressed before such a process can be commercialized; the results from the workshops will also be discussed in the paper.

crude production. Refineries in the U.S. Midwest (PADD II), which is the largest traditional market for oil sands products, cannot process the projected increase of heavy feedstock without additional residual upgrading capacity. The alternative is to build upgrading capacity in Alberta, which could increase production costs and make Alberta crude less competitive in the export market.

Natural gas cost and availability is an issue for more than the oil sands industry. The rapid expansion of Alberta's petrochemical industry during the previous two decades was based on an abundant supply of low-cost ethane derived from natural gas liquids. However, new high-pressure "wet" gas pipelines, high natural gas prices, and diminishing production from the Western Canadian Sedimentary Basin have raised concerns about whether or not the supply of competitively-priced feedstock essential to this industry can be sustained. Oil sands crude is rich in aromatics, which is a detriment when exporting to conventional refineries; however, these aromatics could provide a potential source of petrochemical feedstock.

The need for additional bitumen and synthetic crude oil markets, as well as additional upgrading/refining capacity, has prompted a number of studies to evaluate new markets and product options, including the production of a broad slate of refined products and petrochemical feedstocks, from bitumen. This paper reviews the results of these studies, and discusses the feasibility of adding value to Alberta's oil sands within the province.

Introduction

Alberta has an enviable position as a North American energy hub, providing oil and gas to United States markets through an extensive pipeline network. In addition to conventional oil and gas, Alberta has large reserves of coal and coal bed methane, as well as the massive oil sands deposits that underlie 140,800 square kilometres of the province.

The oil sands have outstripped conventional oil reservoirs as the primary source of oil in the province. According to the Alberta Department of Energy, production of bitumen and synthetic crude oil was close to 158,987.3 million m³/d (one million BPD) in 2003, as opposed to 100,162 m³/d (630,000 BPD) of conventional oil production. If all new projects, and expansions to existing projects currently planned, take place as scheduled, Alberta's bitumen production is expected to triple by the year 2030.

However, the continued expansion of Alberta's oil sands faces significant challenges. Diluent availability is already a problem, water use is facing restrictions, and natural gas is becoming more costly and less available. A further problem is the ability of Canadian and U.S. markets to absorb additional bitumen and synthetic

The Technology Case

In 2003, three industry partners (NOVA Chemicals, Shell Chemicals, and Suncor Energy) teamed with three governmental groups (the Alberta Energy Research Institute, Alberta Economic Development, and Alberta Energy) to develop strategies aimed at transforming products and intermediate streams from oil sands, bitumen, and heavy oil processing into feedstocks for petrochemical plants. The purpose was to provide alternative sustainable sources of competitively priced feedstocks which, together with a low tax regime, constitutes the "Alberta Advantage" for the petrochemical industry. The group developed a long-term strategic plan, which envisioned the development of integrated oil sands processing industrial complexes in Alberta, similar to those located in the U.S. Gulf Coast⁽¹⁾.

The objectives developed from the visioning process led to the commissioning of a joint industry/government study, carried out by T.J. McCann and Associates, which identified opportunities for the synergistic development of the oil sands and petrochemical industries through the cost-effective integration of oil sands production with the upgrading, refining, and petrochemical processes⁽²⁾. Alberta's Industrial Heartland was selected as the geographical

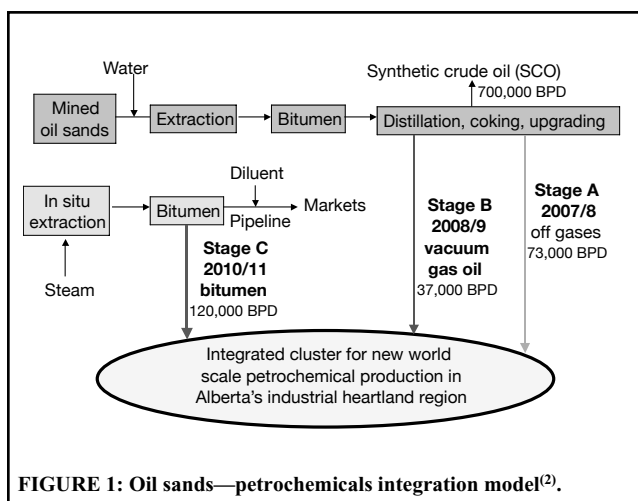


FIGURE 1: Oil sands—petrochemicals integration model⁽²⁾.

region for a conceptual complex, due to its established infrastructure, and the targeted time frame was 2005 to 2020.

The study evaluated the phased development of an integrated complex, starting with the extraction of petrochemical byproducts from existing oil sands process streams, and progressing to full integration of oil sands processing, upgrading, refining, and petrochemical plants producing both high-quality fuels and new world-scale quantities of petrochemicals. A preliminary analysis of available feedstocks, markets, financing, and construction times indicated that a phased approach, as is shown in Figure 1, would be desirable to even out regulatory approvals, construction, and the start-up of new units.

For the first phase of the project, it was assumed that approximately 11,606.07 m³/d (73,000 BPD) of synthetic gas liquids could be extracted from the coker fuel gases at Suncor and Syncrude when the expansion of these plants reaches 111,291.11 m³/d (700,000 BPD) of synthetic crude oil in approximately 2007. The second stage assumes that 5,723.54 m³/d (36,000 BPD) of heavy gas oil and vacuum gas oil from the same production could be hydrotreated, then cracked in a high-temperature, short residence time, dispersed phase catalytic Fluid Catalytic Cracking unit (PetroFCC)⁽³⁾. The third and final phase assumed the processing of 19,078.48 m³/d (120,000 BPD) of bitumen from conventional SAGD type operations, using a simple visbreaker with a vacuum unit to convert bitumen to distillates and to pitch for gasification. The distillates would be fed to expanded processing units from the second phase following hydrotreating, and the pitch would be gasified to produce synthetic gas, which could be converted to hydrogen and ultra-clean fuels.

An economic analysis of the three-phase integrated complex showed an internal rate of return of 15.2% for the base case of conservative product prices. The analysis had a high sensitivity to capital costs and petrochemical prices; the IRR decreased to 10.7% with a 25% increase in capital costs, and increased to 18% if petrochemical prices rose U.S.\$0.05/lb above U.S. Gulf Coast contract prices. Figure 2 shows the production levels used in the analysis.

The study showed that phased integration of oil sands and petrochemical developments to co-produce both high-grade fuels and petrochemicals is technically and economically feasible. However, it was noted that some of the process steps would require further research and development in order to demonstrate performance with Alberta feeds, and to reduce capital and operating costs.

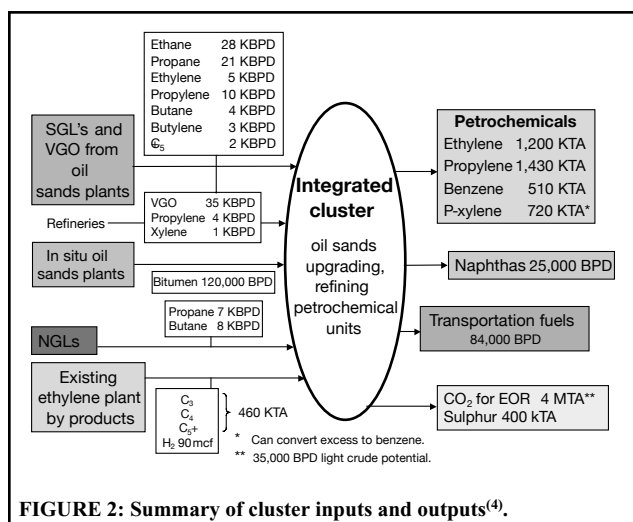


FIGURE 2: Summary of cluster inputs and outputs⁽⁴⁾.

Technical Feasibility

As a result of the McCann study, NOVA Chemicals and the Alberta Energy Research Institute (AERI) launched a joint project to determine if a process could be developed to convert Alberta gas oils into refined products and petrochemical feedstocks. One component of the initial phase of this project was an examination of the various heavy oil processing technologies that could be used for the conversion process, focusing on the olefin to fuel ratios, and the flexibility to change these ratios.

Steam cracking is the most widely used process to produce light olefins from saturated hydrocarbons. In this thermal process, a gaseous or liquid hydrocarbon feed is diluted with steam, then briefly heated in a furnace. Typically, the reaction is very hot (over 900° C), but the reaction is only allowed to proceed for a very short time before the reactants are quenched through contact with a colder fluid. The reaction products are dependent on feedstock composition, the hydrocarbon to steam ratio, the cracking temperature, and on furnace residence time. Table 1 shows the feed dependence of the yield for some common feedstocks. It is apparent from this table that gas oil is a much poorer feedstock for ethylene production (NOVA's core business) than are the lighter natural gas liquids.

Fluid catalytic cracking (FCC) is the workhorse of most refineries, used to convert heavy fuel oil distillates into lighter components, primarily gasoline. Although most FCC research has focused on increasing efficiency and gasoline conversion, recently there has been interest in using this catalytic process to produce light olefins instead. Many companies now market, or have developed, FCC-type processes; for example:

- SINOPEC—Deep Catalytic Cracking (DCC) and Catalytic Pyrolysis Process (CPP);
- UOP—PetroFCC;
- KBR and ExxonMobil—MAXOFIN;
- Japan Petroleum Energy Centre—HS-FCC;
- Indian Oil Corporation—INDMAX; and,
- Neste Oy—NEXCC

Central to these processes are modifications to different zeolite catalyst formulations accompanied by innovations in the FCC hardware, and some changes in the operating parameters.

TABLE 1: Conventional feeds for steam cracking: dependence of yields on feedstock⁽⁵⁾.

FEED	Product (wt.%)	Ethylene	Propylene	Butadiene	BTX	Others
	Ethane	82.3	1.8	2.6	0.7	12.6
	Propane	43.7	21.2	4.1	4.8	26.2
	Butane	42.2	14.6	3.9	4.8	34.5
	Light naphtha	29.3	14.4	4.0	13.8	38.5
	Full range naphtha	25.0	12.8	4.5	11.3	44.2
	Gas oil	25.2	8.3	4.8	11.2	46.6

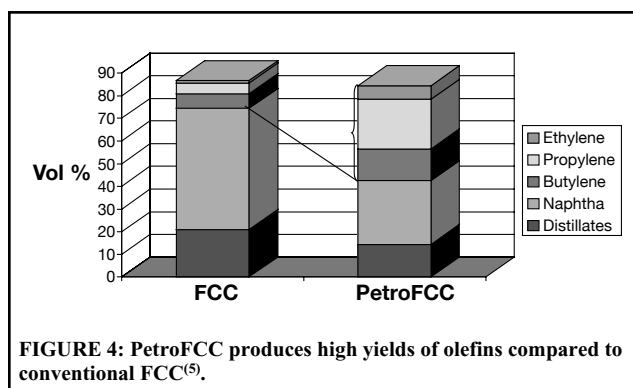
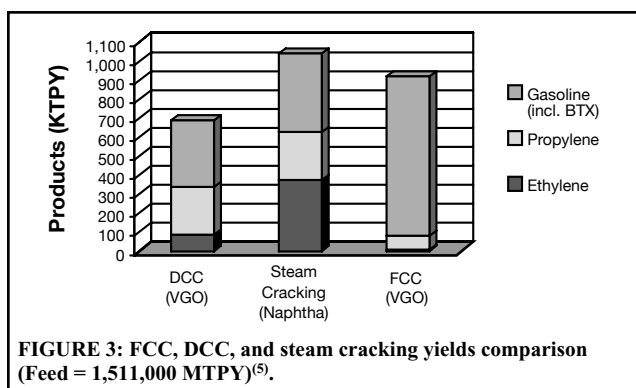


TABLE 2: Bitumen to refined products and petrochemicals: selected cases analyzed in first study.

Case	Refinery Type	Products	Markets
1	Basic upgrader (base case)	SCO	Midwest
4a	VGO hydrocracking and catalytic reforming	Refined products (gasoline, diesel, jet fuel) and diluent	Midwest/California
4b	FCC/alkylation	Refined products (gasoline, diesel, jet fuel) and diluent	Midwest/California
5a	VGO hydrocracking and catalytic reforming	Refined products and petrochemicals (styrene and aromatics)	Midwest/California
5b	DCC/alkylation	Refined products and petrochemicals (styrene, aromatics, and propylene)	Midwest/California

Figure 3 is a comparison of the unit yields for a DCC process, a conventional FCC process, and steam cracking. Naphtha was the feedstock used in the steam cracker, and vacuum gas oil for the FCC and CPP processes. While it is apparent that the DCC process provides a much higher olefin yield than the conventional FCC process, steam cracking would be preferred if olefins alone are the targeted yield.

Figure 4 compares the olefin yield of the PetroFCC process as compared to a conventional FCC process. As can be seen from the figure, the olefin yield for the PetroFCC process is approximately 30% higher than for the conventional FCC process. However, the yields are highly dependent on the feedstock used, and the catalyst type. The PetroFCC process was utilized in the McCann study.

The CPP process is a modification of the DCC process, which can be adjusted to provide for a maximum output of either propylene or ethylene. This is accomplished through a change in the operating conditions. The NOVA/AERI study concluded that this process held more promise than PetroFCC for adaptation to Alberta crudes, as it was developed specifically for heavier feedstocks. This adaptation is currently under investigation in the second phase of the project.

pipeline systems owned by Enbridge and Terasen would transport products to PADD II as well as to the British Columbia West Coast, and from there by tanker to California. The recent announcement of a partnership between Enbridge and PetroChina to develop the Gateway Pipeline makes this scenario much more achievable⁽⁷⁾. It was also assumed that petrochemicals would be transported to the U.S. Gulf Coast market by rail.

A number of cases were analyzed, and the five cases of most significance are shown in Table 2. The process schemes, which had a common input of 31,797.46 m³/d (200,000 BPD) of bitumen feedstock, were optimized to produce refined product volumes and qualities for the two target markets. The outputs for each of the cases are shown in Figure 5.

In Case 1 (the base case), a stand-alone upgrader producing SCO was assumed. The SCO quality would be similar to that of Syncrude Canada, after their most recent expansion (UE1). Approximately 28,299.74 m³/d (178,000 BPD) of SCO could be produced from a crude distillation unit, vacuum distillation unit, and delayed coker, once the products were hydrotreated and combined.

Case 4a used severe hydrotreating, catalytic reforming, and isomerization to produce primarily ultra-low sulphur diesel, gasoline with 30 ppm sulphur for Midwest markets, and some jet fuel

The Business Case

In addition to determining the technical feasibility of producing petrochemical feedstocks from oil sands bitumen, the marketing logistics and economics of producing refined products and primary petrochemicals in Alberta have also been examined in more depth. Two joint industry/government studies carried out by Purvin & Gertz quantified the potential benefits of moving beyond upgrading bitumen to synthetic crude oil by examining new market outlets for oil sands products. One of the cases examined was the development of a world-scale, integrated upgrading and refining project, which would be located in the Fort Saskatchewan area outside Edmonton, as was assumed in the McCann study. This project also included the production of primary petrochemicals, such as olefins and aromatics.

The first study focused on producing refined products for the U.S. Midwest and California markets⁽⁶⁾. A key factor in the study was achieving competitive transportation costs to access export markets; the study assumed that modifications and expansion of

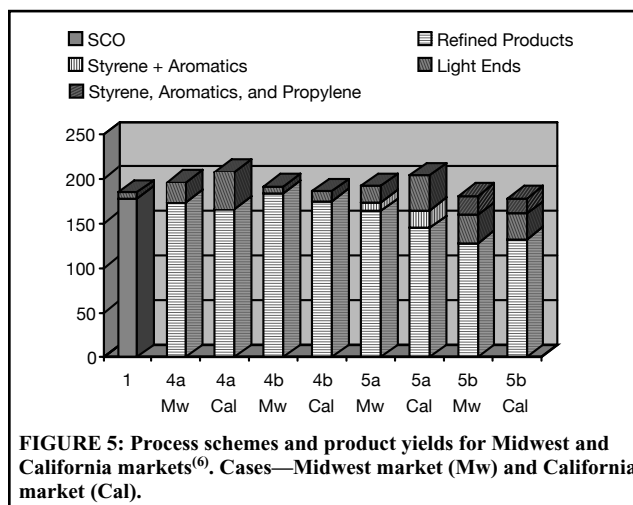


FIGURE 5: Process schemes and product yields for Midwest and California markets⁽⁶⁾. Cases—Midwest market (Mw) and California market (Cal).

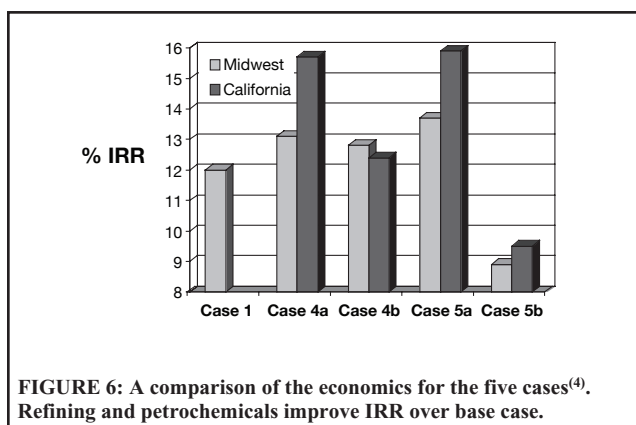


FIGURE 6: A comparison of the economics for the five cases⁽⁴⁾. Refining and petrochemicals improve IRR over base case.

(only for the Midwest case). Larger naphtha treater and reformer units, as well as more severe hydrotreating and processing were required for the California market, to meet the need for larger gasoline volumes and higher quality specifications for gasoline and diesel. This increased the capital cost by US\$203 million over the Midwest market case.

Case 4b was similar to Case 4a, although an FCC unit and an alkylation unit replaced the gas oil hydrocracker of Case 4a to produce more gasoline relative to diesel. Olefins from the FCC unit and the coker units were alkylated to produce more gasoline. Capital costs were US\$966 million higher than for Case 1 for the Midwest markets, and a further US\$668 million higher for California markets.

Case 5a included the addition of an aromatics chemical complex and a world-scale styrene plant to the process of Case 4a. This resulted in the production of less gasoline, because of the aromatics extraction. The capital cost was US\$458 million higher than that of Case 4a for Midwest markets, and for the California markets, the capital cost increased a further US\$303 million.

Case 5b replicated Case 4b, other than a high olefin DCC unit was used in place of the FCC, and an aromatics chemical complex was added. Products included propylene, as well as styrene and xylenes, from the complex.

The base case of the stand-alone upgrader provided a convenient reference against which the benefits from the additional investment needed to produce refined products and petrochemicals could be measured. In Case 1, a 12% IRR was assumed, with a constant bitumen price of US\$9.82/bbl over the life of the project.

A discounted cash flow calculation was used to determine a return on investment on the initial capital expenditure for each case. The analysis included capital and operating costs, the price netbacks, and feedstock costs. Assumptions included a construction period from 2007 to 2020, operation capacity of 25% in 2010, 75% in 2011, and 100% in 2012, as well as a 20-year plant life. A sensitivity analysis addressed the impact of changes in the key variables. Figure 6 shows that, in all cases except for Case 5b, the IRR was greater than the base case, particularly for the California market.

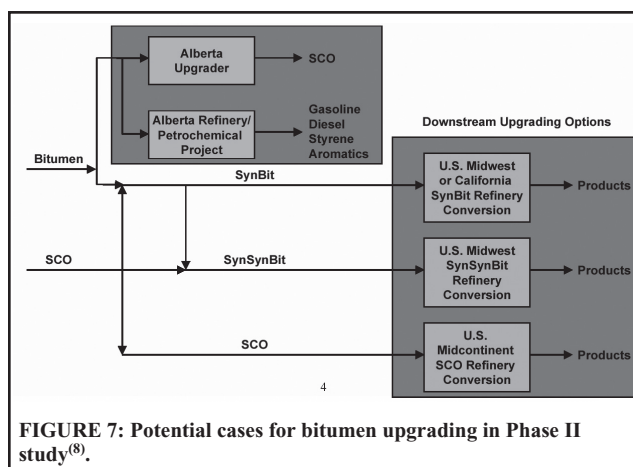


FIGURE 7: Potential cases for bitumen upgrading in Phase II study⁽⁸⁾.

Although the overall IRR was greatest for Case 5a, the incremental IRR was actually lower due to the increased capital costs.

The first study concluded that the production of styrene, added to a refinery complex, provided strong returns in both Midwest and California markets. However, refining and petrochemicals plants are capital intensive, and require large production volumes to be cost effective. Also, unless pipeline and rail infrastructure is in place to carry these large product volumes, success of an integrated complex cannot be assured.

The second study expanded on the first by examining a range of downstream upgrading options, as well as the production of diluent and distillate in Alberta⁽⁸⁾. The additional downstream options included the upgrading of SynBit in the U.S. Midwest and California, upgrading SynSynBit in the U.S. Midwest, and U.S. Midcontinent SCO refinery conversion. Figure 7 shows the various combinations of producing SCO, refined products, and petrochemical products, and Table 3 lists the main cases analyzed. The project was assumed to start in 2010.

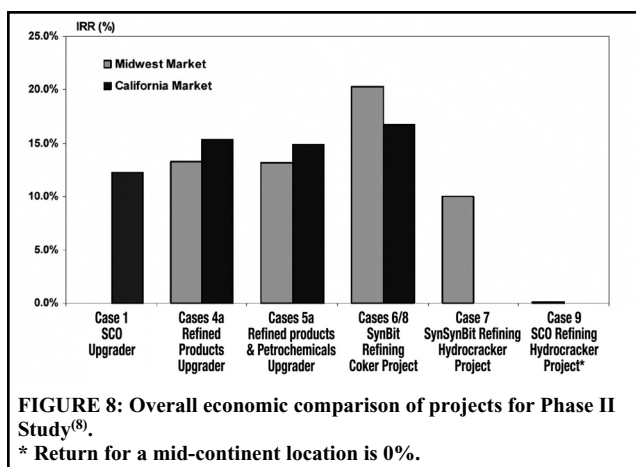
For the U.S. Midwest SynBit case, the base refinery was assumed to be a light to medium 31,797.46 m³/d (200,000 BPD) sour cracking refinery with Southern Illinois logistics and markets. The refinery was upgraded to allow 15,898.73 m³/d (100,000 BPD) of SynBit processing. In the SynSynBit case, the base refinery was the same, but was upgraded to allow maximum SCO feed. The U.S. Midcontinent pure SCO case assumed the refinery was a sweet crude cracker of 7,949.37 m³/d (50,000 BPD) capacity. Finally, for the California SynBit case, 15,898.73 m³/d 100,000 BPD of SynBit was processed in a 39,746.83 m³/d (250,000 BPD) medium sour coking refinery.

Figure 8 shows the overall economic comparison of the various projects examined. The results are similar to those from the first study for the Alberta cases, but the best overall economics are for upgrading refineries in the U.S. Midwest and California to process SynBit.

Although the production of refined products and petrochemicals in Alberta is slightly more favourable economically than

TABLE 3: Bitumen to refined products and petrochemicals: selected cases analyzed in second study.

Case	Refinery Type	Products	Markets
1	Alberta upgrading (base case)	SCO	Midwest
3	Alberta upgrading	Diluent and distillate	Midwest
4	Alberta upgrading	Refined products (gasoline, diesel, jet fuel)	Midwest/California
5	Alberta upgrading	Refined products and petrochemicals (styrene and aromatics)	Midwest/California
6	U.S. Midwest SynBit upgrading	Refined products	Midwest
7	U.S. Midwest SynSynBit upgrading	Refined products	Midwest
8	California SynBit upgrading	Refined products	California
9	Upgrading mid-continent refinery to process SCO	Refined products	Midwest



stand-alone upgrading, the economics are highly sensitive to capital costs. Also, the lack of sufficient transportation for the products is a detriment to the success of this option.

Also, despite the attractive economics for processing SynBit in the U.S., there are only a few candidate refineries in the Midwest and California that would be suitable for conversion. After that, the economics would change, and returns would decrease. The economics for any of the bitumen blends and SCO cases are also dependent on a low SCO price, otherwise, refineries will not invest in processing more of it. However, the market risk was generally lower than expected.

The key conclusion drawn from this study was that, although markets for bitumen blends and synthetic crude oil will likely grow, refinery constraints will limit expansion, and blends and SCO will be competing for the same markets. As a result, the oil sands industry should pursue all avenues for increased market growth, including refined products and petrochemicals. Also, pipelines were identified as a major constraint, which must be addressed to ensure that products can be delivered to export markets.

Business Feasibility

The potential for success of an integrated oil sands production, upgrading, and refining complex outlined in the McCann report led to the formation of the Hydrocarbon Upgrading Task Force. The Task Force is a group of 61 industry and government representatives, with a common vision of developing “a competitive hydrocarbon industry that expands the market for Alberta’s bitumen, and that produces higher value products in Alberta”. Its mandate is to develop the general business case for upgrading hydrocarbon resources to higher value products in Alberta, to communicate and market the opportunities, and to provide advice to government.

To further its mandate, the HUTF held two workshops on February 17 and 18, 2005 to examine issues related to adding value to the oil sands within Alberta. The goal of the workshops was to identify:

- the critical gaps related to markets, regulatory issues, infrastructure, other logistics needs, and process integration;
- the key objectives to help industry and government overcome these challenges; and,
- the path forward for achieving the vision.

The workshops were co-sponsored by the Alberta Chamber of Resources, the Petroleum Society, the Canadian Heavy Oil Association, Canada’s Chemical Producers, EnergyINet, Alberta Energy, Alberta Economic Development, and the Alberta Energy Research Institute.

The workshops were extremely well attended, drawing 156 registrants to both the Calgary and Edmonton sessions. Senior officials from all aspects of the industry (bitumen production, upgrading, refining, petrochemicals, and pipelines), as well as from academia, research, and government attended. Prominent supporters from government included the Honorable Greg Melchin, Alberta Minister of Energy, and the Honorable Clint Dunford, Alberta Minister

of Economic Development. Industry notables were Neil Camarta, Senior VP, Shell Canada, Jim Dinning, former VP, TransAlta, and Paul Clark, VP, NOVA Chemicals.

Registrants were supplied with advance background material prior to the sessions to enable them to constructively use the working groups to identify specific goals to achieve the vision of a world-scale, integrated oil sands production, upgrading, refining, and chemicals complex in the province.

A common theme that surfaced during the course of the workshops was the need for industry to collaborate and share knowledge, both with each other, and with the general public. Lack of infrastructure was an issue, both in terms of transporting finished products, as well as to enable expansion of the oil sands industry. The need for more trained personnel was a major concern that arose in almost every aspect of the discussions. The cost of demonstrating new technology was seen to be an impediment to developing new, lower-cost options to existing processes. Finally, leadership was identified as being critical to the success of the vision, as well as visible championship from both industry and government.

One of the key barriers identified was the risk-averse nature of the industry. Unless industry is given a compelling reason to do so, such as fiscal or regulatory pressure from the government, companies are unlikely to invest in new refining capacity in the mature North American market. Rather, they will invest capital wherever in the world that returns are highest. According to industry, government will have to play an instrumental role if the vision is to be achieved.

Next Steps

One outcome of the workshops was a list of specific action items for the industry and government members of the HUTF to pursue. A priority identified for the HUTF and government was to continue the development of the business case to support the upgrading of bitumen to transportation fuels and petrochemical feedstocks in Alberta. This could be achieved by examining the economics and cost efficiencies of moving up the value chain, as well as by creating synergies in the production processes. Other items that need to be addressed in this area are the feasible feedstock opportunities for bitumen, the environmental benefits of integration, efficiency options, and regulatory requirements. A necessary component of the business case will also be a review of products and markets, as well as an identification of global competition, and what makes them successful. The potential stakeholders in an integrated cluster, and the contributions that they could make to such a complex, must also be addressed.

Another priority is the creation of an environment that will support the development of technology and processes that will help to secure a favourable competitive position for an integrated cluster. Workshop participants suggested that technology gaps be identified where industry can collaborate on fundamental and/or applied research. Much of this work is already underway through the Alberta Energy Research Institute and EnergyINet, including determining the feasibility of a facility to demonstrate novel upgrading technology in the province.

The government was tasked with the objective of reviewing existing policies, and proposing harmonized options for new federal, provincial, and municipal policies and regulations that would support the development of an integrated complex. One suggestion was that comprehensive and clear land use and environmental policies be made a priority. Another was that the provincial government develop fiscal and policy options that would support new bitumen value-added manufacturing. It was noted that the Alberta government must make it clear that developing its resources as far as possible within the province is provincial policy, if this vision is to be achieved.

A review to benchmark other global jurisdictions that have successfully built integrated complexes was suggested, in order to identify best practices that could be adapted to the Alberta situation.

Long-range planning for the necessary pipeline, rail, and road resources that will be required to achieve the vision is a necessity. Other logistical issues, such as labour and infrastructure, are beyond the scope of the HUTF, and must be dealt with by other entities. However, as was made very clear during the workshops and in several of the studies, it is critical that all stakeholders keep the lines of communication open, and work together to create the new "Alberta Advantage".

Conclusion

It has been two years since the initial workshop, where the concept of building an integrated complex to add value to oil sands products all the way up the value chain within Alberta was envisioned. In that time, four studies and two workshops have shown that the concept is both technically and economically feasible, and an action plan is in place to bring the vision to reality.

What needs to be realized by all stakeholders is that this concept will not replace the status quo of bitumen and synthetic crude oil exports. Rather, it will enhance it by providing new high-value markets for a small portion of the province's crude production, which will help to offset predicted steep discounts on bitumen exports. In addition, it could be a source of diluent and hydrogen to support current practices, as well as providing new employment and revenue for the province.

Acknowledgements


The authors would like to acknowledge the contributions of Tom McCann, who gave us hope that this dream could be achieved. He is missed by all.

NOMENCLATURE

BPD	=	barrels per day
CPP	=	catalytic pyrolysis process
DCC	=	deep catalytic cracking
FCC	=	fluid catalytic cracking
HS-FCC	=	high severity FCC
HUTF	=	hydrocarbon upgrading task force
IRR	=	internal rate of return
KTA	=	kilotonnes per annum
SCO	=	synthetic crude oil
SGL	=	synthetic gas liquids

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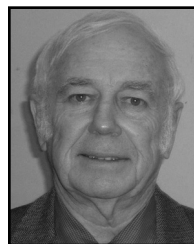
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Paul Clark is the vice president, research and technology, for NOVA Chemicals Corporation. Prior to joining NOVA Chemicals Ltd. in 1994, Paul worked with Dow Chemical Company in a number of positions in Sarnia, and as global operations director, polyolefins R&D in Freeport, Texas. Paul holds a B.Sc. in chemistry from McMaster University. He is currently chair of the Canadian Plastics Industry Association, and is on the Board of Directors of the Alberta Science and Research Authority (ASRA), where he chairs the Strategic Directions Standing Committee. He is also on the Board of Directors for the Centre for Creative Technology (Shad Valley).



Duke du Plessis is senior advisor (energy) with Alberta Economic Development and the Alberta Energy Research Institute (AERI). He works with industry in the areas of oil and gas, oil sands, petrochemicals, and clean coal technologies. His responsibilities include strategic planning, investment attraction, stimulating innovation, and the growth of value-added industries. He is currently involved in a number of joint projects with industry on refined products and petrochemicals from oil sands, clean coal, and gasification technologies, as well as a number of Asian market studies. Duke has a wide range of technical and business experience in the development and commercialization of technology within the private and public sectors. His private sector experience encompasses the synthetic fuels industry at SASOL, South Africa, the oil sands industry in Alberta, and engineering projects in North America, Europe, and Asia. Prior to joining Alberta Economic Development and AERI, Duke held various senior positions in industry and at the Alberta Research Council, Canada's largest provincial R&D organization. Duke is a registered professional engineer and a member of various professional organizations. He holds a Masters degree in chemical engineering from the University of Natal, Durban, South Africa, and a Ph.D. from the University of Alberta, Edmonton.