Report

An Assessment of Refiner Interest in Producing Renewable Alternatives to Gasoline, Diesel, and Jet Fuel.

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EXECUTIVE SUMMARY

The Canadian biofuels production industry has grown significantly over the past decade, in large part due to the implementation of federal and provincial renewable fuels requirements and supporting programs. Investment in this industry sector has variously come from conventional fuels "primary suppliers" – the principal users of biofuels under the legislative mandates – and third-party interests. Investment on the part of conventional fuels producers has been inconsistent across the range of those players however, suggesting a diversity of views as to the associated risks and rewards. The report herein seeks to clarify those industry views; this has been accomplished largely through a series of discussions with senior industry representatives.

As expected, our discussions with primary suppliers in Canada yielded a diversity of views towards investments in the production of renewable alternatives to gasoline, diesel and other fuels. This held true for both domestic and international investment strategies. This diversity of views, as well as those common elements that emerged from our discussions, form the basis for our analysis presented herein.

Generally, primary suppliers' direct investments in biofuels production were described as having been justified against one or more of the following criteria:

- Whether the strategy would address a perceived threat to security of supply;
- Whether this strategy would result in measurable synergy with existing areas of business. This could be in reference to asset utilization or at an operational level with respect to refining or distribution;
- Whether this strategy would result in meeting a certain assured threshold of return on the capital employed.

Most producers shared the view that under current market conditions, there is little incentive to invest in renewable alternatives to gasoline. The Canadian ethanol market is well supplied and there was a common view that little if any synergy is gained from incorporating ethanol production into existing conventional fuel production infrastructure. In most cases, third-party supply of ethanol directly to terminal facilities was described as being the more cost effective and efficient supply strategy. Margins in the ethanol industry have been under significant pressure, and considering current market conditions, all respondents considered that an acceptable return on capital would not be assured if a "greenfield" site were to be built today. If an opportunity to acquire undervalued assets or to meet a specific strategic need were to materialize however, these could be mitigating factors.

The perception among primary suppliers is that the supply infrastructure of renewable alternatives to diesel is generally underutilized and that the security of their supply is therefore not a concern at present. However, the majority of Canadian bio-based diesel supply is being imported, and there is increasing international competition for the type of renewable diesel brought into the Canadian market. There may therefore be a future need to re-evaluate the issue of supply security for renewable diesel in the Canadian market. While there is some potential for synergy in co-locating renewable diesel production, refiners indicate the amount of capital required to build a facility large enough to take advantage of economies of scale is prohibitive when potential economic returns are considered. This is further complicated by the relatively small size of the Canadian renewable diesel market, which would likely result in a large portion of a new facility's production being destined for export.

Co-processing of renewable feedstock with conventional petroleum feedstock can provide a synergistic benefit to producers, thereby offering a more scalable and flexible option relative to standalone production. Co-processing raises concerns however, over the potential effect on conventional fuel yields and potential impacts on the operating environment of existing refining infrastructure used in conventional production. There is also uncertainty over the merits of a co-processing operation specifically relating to the "accounting" of inputs and outputs under federal or provincial renewable fuel regulations.

Investment into the production of renewable alternatives to other refined petroleum products (such as jet or other products) is felt unlikely to develop without mandates in place to support its growth. Another factor discouraging direct investment in this area is the perceived poor return on investment that would likely be realized.

Global investment in biofuels research, development and production is robust and growing; however this is not necessarily represented among Canada's primary suppliers. Many multinational petroleum suppliers operating in Canada are choosing to make their strategic investments elsewhere. These approaches are driven by a range of views, including:

- An "unlevel playing field" with respect to biofuels regulations, subsidies and government support relative to other countries (including the U.S.);
- The long-term stability of Canadian biofuels mandates and associated incentives;
- International access to more desirable and secure supplies of feedstock;
- The relatively small size of the Canadian biofuels market and its current abundance of supply sources;
- The poor positioning of Canadian refining facilities and other supply infrastructure with respect to ease of access to promising biofuels export markets.

Domestic petroleum producers expressed their intentions to continue evaluating opportunities for strategic investments in biofuels, although their evaluations will likely be based on similar criteria to those discussed in this report. An assessment of the current market opportunities and investment environment for petroleum producers in Canada points to limited near-term growth in direct investment into renewable fuels production.

INTRODUCTION

Canada has implemented its Federal Renewable Fuels Regulation (RFR) under the Canadian Environmental Protection Act, 1999 (CEPA, 1999). The Regulation requires petroleum fuel producers and importers to have an average renewable fuel content of at least five percent in gasoline and an average of at least two percent renewable fuel content in diesel fuel and heating oil[1]. The renewable fuel requirements are based on each company's volumes of gasoline and distillate "pools" which it produces or imports from all of its operations. Refiners and importers may also buy or sell tradable Compliance Units (CUs) to meet their requirements under the Regulations. A number of provinces also have their own renewable fuels mandates which mostly serve to generate investment and employment opportunities in those jurisdictions.

As a result of these mandates and supportive federal and provincial programs, the biofuels industry in Canada has grown significantly over the last decade. According to the Canadian Renewable Fuels Association (CRFA) the industry as of 2010 had invested $2.3 billion towards production facilities resulting in close to 2 billion litres per year of domestic production capacity for renewable fuels[2].

The mandates and related incentives have supported a robust and growing Canadian biofuels industry that has the built capacity to supply domestic demand for ethanol and biodiesel created by federal and provincial mandates. Nevertheless, 2012 ethanol demand exceeded mandated volumes and available capacity, and biodiesel demand has been lower than anticipated. Future growth in biofuels production may be used domestically - displacing imported biofuels - or destined for export markets.

Petroleum producers are important stakeholders and participants in Canada's biofuel industry. As "primary suppliers" they have obligations under the RFR legislation, and therefore may pursue a compliance strategy where they have a role in producing, transporting, storing, blending or marketing biofuels. Although no specific obligation exists, some primary suppliers have directly invested in renewables production infrastructure, while many others have opted to meet their mandates through third-party renewables supply arrangements.

That there are fundamental differences in approach as to whether or not to integrate direct control of renewable fuel production into the conventional fuels industry, is suggestive of a range of views with respect to the risks and rewards of doing so. Moreover, it is suggestive of a range of views with respect to future opportunities that might exist in the production of renewable fuels for both domestic and export markets.

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[1] On December 31, 2012, Environment Minister Peter Kent proposed an amendment to the *Renewable Fuels Regulations* that would see a permanent national exemption from the 2% renewable content requirement in home heating oil, as well as a 6-month extension to the exemption from the 2% renewable content requirement for diesel fuel for Canada's Maritime Provinces.

[2] Canadian Renewable Fuels Association. November 2010. "Growing Beyond Oil Delivering Our Energy Future: A Report Card on the Canadian Renewable Fuels Industry"

Most refiners in Canada are not producing biofuels or do not appear to be engaged in this growing market; there is a need to understand why that is the case. Natural Resources Canada has commissioned MJ Ervin & Associates to conduct a study that specifically addresses the following aims:

1. An examination of refiner's projects (both existing and proposed) in Canada or abroad.
2. An investigation of whether refiners have explored the market opportunities for biofuels in Canada (or internationally). An analysis of their explorations and their considerations, with respect to participation.
3. A SWOT (Strengths/Weaknesses/Opportunities/Threats) analysis with respect to co-processing renewable fuel feedstock and petroleum feedstock to produce biofuels at Canadian refineries.

The project was carried out through discussions with most of Canada's largest fuel producers. A formal discussion outline (Appendix B) guided each interview and the participant's contributions are summarized and analyzed herein. As a result of the limited number of Canadian producers, many of the contributions offered by the participants are expressed in generalities throughout this report in order to protect the confidentiality and the proprietary nature of the discussions.

The participant companies were Suncor Energy Inc., Ultramar Ltd., North West Redwater Partnership, Husky Energy Inc., Chevron Canada Limited, Shell Canada Limited, Imperial Oil Limited, and Irving Oil.

EXAMINATION OF REFINER'S INVESTMENTS IN BIOFUELS

There has been significant growth in the global biofuels industry over the last decade. This comes in part from a concerted effort by governments to support this growth through the enactment of renewable fuels mandates, a strong focus on the reduction of GHGs via transportation fuels policies, and programs aimed at supporting the industries' development and ongoing viability. Most traditional petroleum companies acknowledge that biofuels are part of the future of their business. In some cases, petroleum producers have chosen to invest directly in the development of biofuels research, technology and production facilities. This section provides an overview of the investments made by Canadian petroleum producers as well as their global parent companies.

CANADIAN AND GLOBAL INVESTMENTS

Suncor has invested in the largest ethanol producing plant in Canada. It is located in St. Clair, Ontario (opened in 2006) and has a capacity of 400 million litres annually. This represents more than half of Ontario's average renewable fuels requirements. The plant itself is operated as a subsidiary of Suncor and produces corn based ethanol. While Suncor is committed to the renewable fuel business they, like most other producers, will likely continue to evaluate opportunities on a long-term strategic basis. They have not invested directly in Canadian biodiesel production.

Husky Energy owns and operates two ethanol production facilities each with a capacity of 130 million litres per year. They have not invested in any type of bio-based diesel facility.

Chevron Corp. is heavily involved in research and development towards the advancement of their renewables' technology. Globally, they have made several focused investments targeting the development of next-generation biofuel technologies through the operation of Chevron Technology Ventures (CTV). CTV has made investments in enzyme developer Codexis, Inc. and advanced biofuel technology developers LS9, Inc. and Catchlight Energy[3]. This does not necessarily reflect in a Canadian context for Chevron as it is a relatively small part of the multinational entity.

Ultramar Ltd. is a wholly owned subsidiary of Valero Energy Corporation and their Canadian operations have had no direct investment in biofuels production. However, Valero is opening a renewable diesel production facility in St. Charles, Louisiana mid-2013 as part of a joint venture with Darling International Inc. The facility will produce roughly 580 million litres per year of HDRD from animal fats and used cooking oils, representing approximately $400 million in investments. The relative size of the Canadian biofuels market and concerns over the availability of feedstock would make a similar investment in Canada unlikely. Their HDRD facility in Louisiana is a medium sized plant in relation to others but would produce enough renewable diesel to supply roughly 90 percent of Canada's mandated requirement. They also operate ten ethanol production facilities throughout the U.S. under a subsidiary (Valero Renewable Fuels Company LLC)[4]. Valero has also made several focused R&D investments in advanced biofuel technology including diesel produced from algae with Algenol Biofuels, Inc. and the production of ethanol from cellulosic material with Mascoma Corporation.

While **Imperial Oil** has not invested directly in renewable production in Canada, ExxonMobil (their global parent company) has made some selective investments in acquiring technology for advanced biofuels. Their investment focus has been primarily in the algae-based production of renewable fuels through a strategic alliance with Synthetic Genomics, Inc. that represents the potential for more than $600 million in research and development[5]. ExxonMobil's global biofuels strategy could be characterized as relatively conservative.

Royal Dutch Shell has been one of the most aggressive global investors in renewable fuel production. They have made significant investments into the production of Brazilian sugar cane ethanol through dealings with Cosan[6]. Raizen - their recent multi-billion dollar joint venture with Cosan - has become the focus of their renewables strategy. It is billed as one of the most competitive and sustainable energy companies in the world, producing over 2 billion litres of low-carbon intensity ethanol fuel, most of which is bound for export to a range of countries[7].

In Canada, Shell had made investments into the development of cellulosic ethanol through Iogen Corp., an Ottawa based biotechnology company. With their strategic biofuels focus

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[3] Hart Energy Publishing. "Global Refining and Fuels Report". July 2011.
[4] Valero website. http://www.valero.com/Products/Renewables/Pages/Home.aspx.
[5] ExxonMobil Algae Biofuels Research and Development Program.
[6] A Brazilian based conglomerate focusing on sugar cane and ethanol production.
[7] Cosan/Shell media release. June 2, 2011.

shifting towards Raizen, the Iogen project was cancelled. Existing investments and proprietary technologies were transferred to Raizen, where they are pursuing the commercialization of biomass-to-ethanol in Brazil. This cellulosic ethanol facility is to be co-located with an existing Raizen plant in Sao Paulo.

Shell also has a sizeable joint venture with Virent Energy Systems aimed at the production of renewable gasoline from beet sugar using proprietary technology. The pilot plant is scheduled to come online in the Houston area closer to 2020 and is targeting a modest production of 38,000 litres annually.

With the exception of Husky and Suncor's production of ethanol, there is little renewable fuels production resulting from direct investment by Canadian refiners. Conversely, many of the multinational refiners with operations in Canada have made more significant investments internationally.

Our discussion with refiners sought to examine their views on investment and market opportunities relating to the production of renewable fuels. The analysis that follows considers their perspectives regarding their past and future investment decisions, and the factors driving those perspectives.

OPPORTUNITIES FOR BIOFUELS IN CANADA

RENEWABLE ALTERNATIVES TO GASOLINE

The most widely available renewable alternative to gasoline is ethanol; all of Canada's primary suppliers are currently meeting their requirements for renewable content in gasoline through the blending of ethanol into their gasoline pool. For this reason our assessment of renewable alternatives to gasoline will only address ethanol.

Canadian demand for renewable alternatives to gasoline, resulting from both federal and provincial mandates, represents approximately two billion litres based on the current level of gasoline consumption. Built production capacity of all operational ethanol facilities in Canada[8] is approximately 1.9 billion litres annually, with reported production in 2012 of 1.73 billion litres. Canada imported (on a net basis) close to one billion litres of ethanol in 2012, with the U.S. being the origin for most of those imports. This suggests that on balance, primary suppliers in Canada blended above their five percent requirement[9] in 2012, largely due to the lower price of ethanol relative to conventional gasoline blendstocks.

There are signs that the North American ethanol market is well supplied considering that the U.S. is currently blending close to a "blend wall" of ten percent[10] of their gasoline pool, the number of idled ethanol plants in the U.S. grew to at least 20 by January 2013 and U.S. ethanol

[8] Natural Resources Canada. This is based on producers who are proponents of the federal ecoENERGY for Biofuels program. There may be some production that is not part of this program but this likely represents a small amount of volume.
[9] Approximately seven percent based on consumption figures in the Statscan report 45-004-X for 2012.
[10] EIA Today in Energy. March 2013.

exports continued to grow in 2012. An important consideration in a primary supplier's decision over ethanol supply strategy is security of supply. In the case of ethanol, the market is well supplied by a diversity of third-party producers both in the U.S. and Canada. Refiners did not express any concerns over the availability of supply for ethanol or their ability to meet their mandated requirements through a third-party supply strategy.

Most of the refiners interviewed stated that there is no strategic advantage to the co-location of ethanol facilities with refineries. The production models, as well as the supply and distribution requirements, are distinctly separate and therefore offer very little if any synergy. Indeed, in many cases co-location would lead to higher costs since ethanol blending must take place at the terminal, not the refinery, due to inherent issues with transporting ethanol blended gasoline via pipelines[11]. Without any particular benefit to co-locating ethanol production facilities with those of a conventional refinery, the most cost-effective model that has emerged has been that of ethanol plants located proximally to their source of feedstock (corn, for example).

Refiners have indicated that they routinely evaluate investing in ethanol production (not necessarily co-located facilities) against commonly accepted criteria; acceptable return on capital was cited as chief amongst these. The prevailing thought among refiners interviewed was that as of late, ethanol-producing facilities have generally struggled to provide healthy returns. There is also a sense that for the most part, the industry is reliant on the continuance of subsidies, favourable funding arrangements and the preservation of the renewable fuels mandates themselves in order for these facilities to be successful, none of these being assured in the long term. In many cases when investments have been made (either domestically or globally) it has been done on the basis of finding "undervalued" assets or strategically meeting a specific need such as addressing regional supply inefficiencies.

Cost reductions or efficiency gains could also motivate refiners to invest in ethanol producing facilities. This would likely be evaluated on an "individual case" basis depending on such factors as geography, the dynamics of regional product markets and the blending strategy of that particular producer. It is difficult to assess this particular consideration in a broader context. However, given that investment decisions are generally measured against the criteria discussed above (return on capital employed, increased efficiency or other synergies), and concerns about security of supply, there was no expressed likelihood of direct investment in ethanol production in the foreseeable future.

RENEWABLE ALTERNATIVES TO DIESEL

There are generally two types of renewable alternatives to diesel being used to meet the Canadian mandated requirements. The first, fatty acid methyl ester (FAME), is produced through the transesterification of, animal or plant based fats. FAME's properties - such as cloud and pour point – are generally not considered favourable in colder temperatures. FAME biodiesel is the only renewable alternative to diesel produced in commercial quantities in Canada.

[11] Issues include corrosion of the pipeline, and product quality issues because of the absorption of water and other impurities (when sharing the pipeline with other petroleum products).

The second, HDRD (hydrogenation-derived renewable diesel), is a renewable alternative to diesel produced by hydrogenating animal or plant based fats to remove impurities (oxygen, nitrogen and metals) through dedicated hydrotreating facilities or potentially, through existing refinery infrastructure. HDRD feedstocks can include oil from palm, soybean, canola, and rapeseed sources as well as animal tallow and other fats or oils. The key benefit of HDRD is that it essentially matches or exceeds the specification for traditional diesel fuel, giving it a "drop-in" capability. Its properties in cold weather are similar to that of conventional diesel[12]; therefore, it is much more suited to most of Canada's climactic regions. It can also be used within the existing conventional production and distribution infrastructure, and is suitable for "co-processing" with conventional petroleum feedstocks.

Demand for renewable alternatives to diesel in Canada is approaching 600 million litres annually. Current built biodiesel production capacity is approximately 555 million litres per year; this is expected to grow to 820 million litres per year[13] once a 265 million litre plant in Lloydminster, Alberta is fully constructed (anticipated for the end of 2013).

Despite FAME being the only bio-based diesel produced in Canada in commercial quantities, concerns surrounding its cold weather properties have some refiners opting to use renewable diesel (such as HDRD) to meet a large part of their federal and provincial mandates[14]. In a 2011 survey, refiners anticipated that less than 10 percent of the renewable alternatives to diesel used to meet federal and provincial regulation would come from Canadian sources[15].

A large portion of Canada's biodiesel mandate is therefore being met through the import of HDRD. According to a survey of diesel producers and importers[16] the amount of HDRD being used to meet federal and provincial mandates is roughly half of all renewables demand, and is expected to increase in the future. This is very likely a conservative estimate, as respondents suggested that a decrease in the price premium for HDRD would result in a more pronounced shift towards its use. The refiners we interviewed for this project reported that they were all, to varying degrees, meeting their mandated requirements through the purchase of HDRD and that it is expected to become the key means by which Canadian suppliers meet their bio-based diesel mandates. The majority of this HDRD supply was coming from one of Neste Oil's major production facilities in Singapore or Rotterdam.

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[12] Neste's product info guide can be found here: http://www.nesteoil.com/binary.asp?GUID=542AF06E-FD19-4BC3-9159-28F3B390BA2E

[13] Natural Resources Canada. This is based on producers who are proponents of the federal ecoENERGY for Biofuels program as well as another facility set to come online in 2013. There may be some additional production that is not part of this program but this likely represents a small amount of volume.

[14] With the exception of the Lower Mainland of British Columbia where the climate is less of an issue for FAME use.

[15] ÉcoRessources Consultants. February 2012. "An Update of Renewable Diesel Infrasturcture in Canada".

[16]Ibid

Neste controls almost 90 percent of the existing "stand-alone" production capacity for HDRD globally and are major exporters to both Europe and Canada[17]. There is no HDRD production in Canada; the only existing stand-alone facilities in North America are located in the U.S. There is also a limited amount of co-processed HDRD capacity in the U.S. The amount of HDRD imported into Canada from the U.S. may increase as more of their planned production capacity comes online. The remaining Canadian import need for biodiesel is currently being met through canola-based biodiesel produced in the U.S. since its cold weather properties are more desirable than tallow or grease based FAME.

Security of Supply

A fundamental consideration for Canadian producers when deciding whether to source their biodiesel blending components from a third party or to invest in their own production, is security of supply. While there is an inherent supply risk when importing blendstock, in the case of HDRD in Canada, there is a perception among refiners that the supply has been coming from reputable and under-utilized suppliers.

As earlier stated, most of Canada's supply of HDRD is sourced from Neste production facilities outside of North America. A small but growing amount of supply is originating from the U.S. Gulf region however. Neste's overseas facilities were underutilized up to the end of 2011, but as **Table 1** shows, Neste's utilization has significantly improved, likely forming the impetus for growth in HDRD production capacity in the U.S. and elsewhere: another 1.7 billion litres of annual HDRD production is proposed or planned to come online over the next few years[18]. This increased capacity (920 million litres in Europe and 700 in the U.S. [19]) will almost certainly lower global utilization rates, and much of this expanded capacity will be well positioned to serve the markets that Neste currently supplies, including Canada.

Table 1: Neste Oil Reported Production 000 ton/year (source – Neste Annual Reports and Financials)

Year	Capacity	Production	Sales	Utilization (%)
2010	1,180	340 est.	270	29%
2011	1,980	682	628	34%
2012	1,980	1,849	1,665	93%

The U.S. has not been a major export destination for Neste's production of HDRD until recently. The primary feedstock for Neste's HDRD production is palm oil, which does not meet the RFS2 requirement for a 20 percent reduction in GHG emissions[20] to qualify for a basic renewable fuels

[17] ÉcoRessources Consultants. March 2012. "Study of HDRD as a Renewable Fuel Option in North America".
[18] IBID
[19] IBID
[20] While Neste's Porvoo and Singapore facilities are considered "grandfathered" (because of when they were constructed) and not subject to the 20 percent GHG reduction requirement, they are still subject to the 50 precent GHG reduction requirement for both biomass-based diesel RINs and advanced biofuels RINs.

RIN[21], or the 50 percent reduction required for advanced biofuels. Neste has only recently entered the U.S. biofuels market with HDRD production from its Finland based refinery using waste and residue-based feedstocks[22].

Canada's Renewable Fuel Regulation does not differentiate between types of bio-based diesels and so regardless of feedstock, Neste's production is suitable for Canadian producers and importers. Until recent global HDRD demand growth outpaced production growth, Canadian refiners appeared not to be concerned about the reliability of third-party supply of HDRD. This was likely a factor in their decision regarding direct investment into biofuels production at the time, and with an expected near-term increase in global capacity, concerns over security of supply are likely to remain low.

There is a significant price premium for HDRD relative to FAME: in 2010, roughly 30 U.S. cents per gallon[23] and roughly 40 cents per gallon by 2012 (roughly 7 to 10 cents per litre). There is additional value attached to HDRD due to its higher energy content, higher cetane, and better cold temperature characteristics, making the price premium acceptable for many Canadian producers. One wild-card with respect to HDRD in Canada is the future of this price premium. While there is growing demand for HDRD globally, there are feedstock limitations in the U.S. market, and the European market remains oversupplied with conventional biodiesel[24]. This has put significant downward pressure on the margins of all bio-based diesel producers that supply Europe. With the significant amount of HDRD production expected to come online in the near future, this could put further downward pressure on these premiums. If this price premium trend occurs, it will provide further incentive for Canadian producers to use HDRD to meet their RFR requirements.

Given that a price premium for HDRD will undoubtedly continue to exist (albeit likely at a reduced degree), there is arguably some incentive for Canadian refiners to produce HDRD at their facilities. Whether they choose a stand-alone approach or a co-processing approach, there are potentially synergies between HDRD production pathways and conventional fuel production. Our discussions with refiners revealed several factors affecting their investment decisions surrounding such a possibility.

Capital Requirements and HDRD

One widely discussed issue was the capital-intensive nature of HDRD production. While FAME production is highly scalable, HDRD is inherently very capital intensive at the "economies of scale" needed for a viable plant. Given Canada's modest demand for bio-based diesel, a facility the size of Neste's Singapore plant for example (906 ML per year), could supply the entire national bio-based diesel requirement, and have a third of its production left over for export into an already well-supplied global market. Several refiners estimated the capital cost on a large

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[21] RIN refers to a Renewable Identification Number; a number assigned to a batch of renewable fuel in order to account for its production and use. RINs can vary by the type of renewable fuel they are attached to. Once detached from that batch of fuel (upon blending) the RINs can be traded on a secondary market as a type of renewable fuels credit.

[22] Neste Oil Corporation Press Release. April 26th, 2012.

[23] ÉcoRessources : HDRD sold in Canada relative to FAME biodiesel sold in Canada.

[24] Neste Oil Annual Report 2011.

stand-alone HDRD facility to be in the one billion dollar range; this is consistent with Neste's reported capital costs for their larger plants in Singapore and Rotterdam. A capital outlay of that magnitude would require the assurance of significant returns in order to be feasible. To date however, the returns on existing HDRD facilities have been poor, and many rely on the sale of a varying mix of co-products[25] to support their operations. Neste's renewable fuels division has not posted a positive operational profit in any quarter since their facilities have come online[26] and the perception among refiners is that it would be extremely difficult to see a healthy return on capital employed (ROCE) in the Canadian market.

While most have investigated the possibility, there was a strong consensus among those interviewed that it would be quite unlikely that a large-scale "stand-alone" commercial HDRD facility would be built in Canada. If it were to be undertaken, the facility would need to focus on export as its largest market. It would also likely need to co-locate with an existing coastal refinery in order to facilitate its likely export focus,[27] and to provide flexibility of feedstock choices based on price and quality. Refiners are facing many challenges however, particularly those that are coastally based: high imported crude feedstock costs, declining product demand, increased competition for refined products in the Atlantic Basin, and a progressively stringent regulatory environment, to name some. This has resulted in several coastal-based North American facilities idling or closing operations, and several facilities have been or are in the process of being sold. As a result, investing capital into biofuels production is not likely a current consideration for many Canadian refiners, particularly those few that are coastal-based, which as described, are likely the only possible locale for a co-located HDRD plant.

Further to this, the lack of harmony between federal and provincial mandates was cited as creating inefficiencies and a riskier investment climate for producers. For example, if a large national producer were to produce HDRD in a particular part of the country, this might be sufficient to meet the federal renewable alternatives to diesel mandate but it may not satisfy compliance requirements with each of the provinces' mandates. That producer would still need to configure their supply plan to accommodate for each of these levels of regulation. **Table 2** lists the provincial mandates that exist in parallel to the federal biodiesel mandate of two percent. Moreover, the potential for changes to any one of these federal or provincial mandates or regulations, poses a significant risk of investment. In order to assure a reasonable return on such investments, some refiners stated a need for a degree of stability in the long-term commercial and regulatory environment they operate in. The limited direct investment by Canadian refiners in biofuels research and production is therefore in part, a consequence of Canada's federal-provincial patchwork of renewable fuels mandates and regulations.

[25] Such as oxygenated by-products and propane.
[26] This is in spite of the fact that they more than doubled their sales of NExBTL in 2012 and their ultilization rate is close to capacity.
[27] Which would largely represent European markets and coastal U.S. markets.

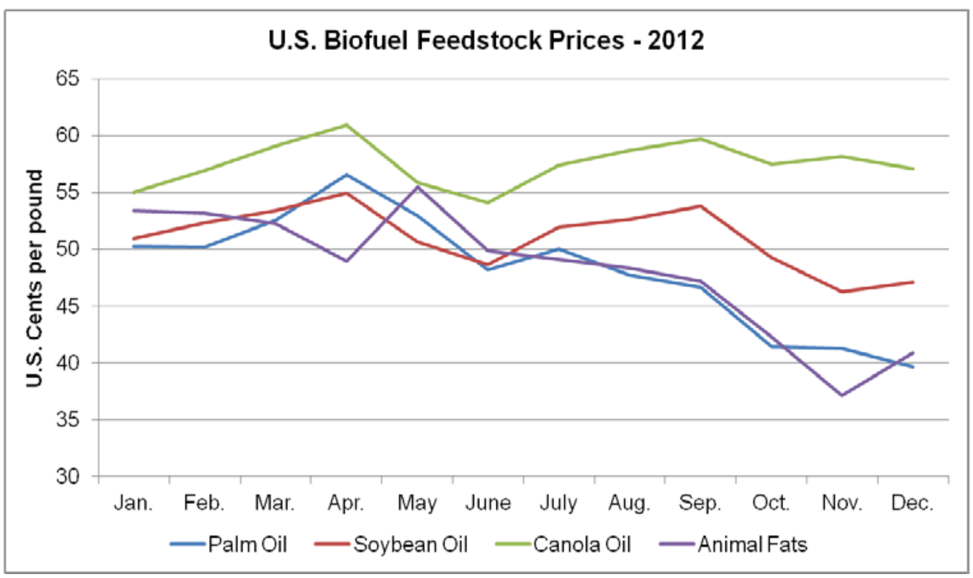
Table 2: Provincial Biodiesel Mandates

Province	Renewable Alternative to Diesel Mandate
British Columbia	4%
Alberta	2%
Saskatchewan	2%
Manitoba	2%

Limitations of Domestic Feedstock Supply

Refiners expressed concern over feedstock supply for domestic HDRD production. HDRD feedstock typically includes soy and canola oil, yellow grease, tallow, other waste products and palm oil. The most available (and likely) North American feedstock would be soy and canola oil along with other waste fats. These also happen to be the least economical options from a production standpoint. **Figure 1** shows the movement of prices for various HDRD feedstocks. Considering Neste's facilities utilize roughly 95 percent palm oil and waste fats (the two least expensive options) and their facilities have not demonstrated the ability to earn a positive ROCE, canola and soy bean oil options are seen as prohibitively expensive. Considering that feedstock costs account for roughly 80 percent of the operating costs at an HDRD plant [28], this becomes a key consideration when assessing the feasibility of a potential production facility. The more economical alternatives for production (palm oil and animal fats) however, present issues with respect to security of supply and potential export of production to the U.S. (due to RFS2 constraints, as earlier discussed).

Figure 1: 2012 Prices for HDRD feedstocks (US cents/pound)



Source: US Department of Agriculture Oil Crops Yearbook 2013

[28] ÉcoRessources Consultants. March 2012. "Study of HDRD as a Renewable Fuel Option in North America".

Palm oil would need to be imported in large quantities, which could be a limiting factor in selecting the location for a facility. For example, co-locating a facility with an inland refinery (such as in Edmonton) would make it difficult to choose palm oil as a reliable feedstock. Furthermore, the choice of palm oil limits export of the product to the U.S., since biofuel produced from palm oil sources does not meet the RFS2 requirement for a 20 percent reduction in GHGs. Animal and waste fats are a slightly more expensive option than palm oil; nevertheless, they are more readily available in the North American market and are currently being used by existing HDRD facilities in the U.S. The concern with animal fats is that there is limited supply relative to the amount required to meet the input demand of a large standalone facility. Currently, most North American supply of animal fat is being used by the feed industry or is already earmarked to supply existing biodiesel or renewable diesel facilities[29]. It would be difficult to secure enough incremental supply of animal fat to sustain another medium or large-sized HDRD facility in North America. A more realistic scenario for such a facility is a combination of available feedstocks (canola, soy and animal fats) which again, threaten its financial viability through higher feedstock costs relative to palm based production.

JET FUEL

Refiners shared a common view that large-scale renewable jet fuel production is not likely in the foreseeable future. There are currently no mandates to require the use of renewable jet fuel and there are significant technical hurdles to production on a commercial scale. There are some emerging technologies that may result in “drop-in” type jet fuel being produced; however these same processes can yield advanced renewable diesel, and it appears that the current focus is on the production of the latter.

Canadian policy in this area includes the recently released “Canada’s Action Plan to Reduce Greenhouse Gas Emissions from Aviation”. It details support for research and development of alternative aviation fuel production and plans to work with the aviation industry and key trading partners to identify opportunities and to pursue collaborative efforts to reduce GHG emissions from aviation. It contains no mandates for such results however.

One of the primary drivers behind interest in renewable alternatives to jet fuel had been expected demand (and an associated price premium) for a low carbon alternative to jet fuel in response to legislation enacted in the European Union (EU). The EU Emissions Trading Scheme (ETS) requires airlines to lower carbon emissions for all European flights and was originally launched as an amendment (in January 2012) to the more comprehensive EU climate policy. This was intended to cause International carriers flying through European airports to buy quantities of lower-carbon jet fuels - likely at a premium - to avoid penalty or costs intended to mitigate the carbon requirements under this legislation. This was based on the assumption that carbon credits would be much more costly than they currently are. As a result, the market for low carbon jet fuels has not materialized as expected.

The legislation has also faced strong pushback from the international aviation industry and foreign governments, and has accordingly been revised to lessen the financial impact on airlines. The EU itself is considering its options with respect to the aviation portion of the

[29] Ibid

scheme - with cancellation being an option. Just recently, the European Commission presented a legislative proposal to defer the requirements for airlines flying into and out of Europe[30].

GENERAL FINDINGS

Government Policies

Several refiners expressed a concern over the stability of the mandates themselves. The viability of most biofuel production plants is largely dependent on sustained renewable fuels mandates, as well as continued subsidies to support its growth. Among those producers interviewed, there is scepticism over the long term viability of the current regulations and the consequent impact on biofuels-related investments, of potential changes to regulations. There is also a consensus that additional federal and provincial incentives and/or modifications to the way CUs are awarded (specifically for co-processing) would be required to support the push for second-generation diesel production at Canadian facilities.

Some interviewees representing multinational petroleum companies cited the considerable gap that exists between U.S. and Canadian incentive programs for advanced biofuels. The U.S. RIN-based system differentiates between types of biofuels and establishes criteria to allow advanced biofuels to qualify for additional or more expensive RINs; this can make the U.S. a more attractive investment opportunity. A Canadian-based advanced biofuels producer might possibly favour U.S. markets over those in Canada, in order to optimize revenue from that product. This was cited as a possible reason for a lack of direct investment in advanced biofuel production by Canadian refiners.

For multinational producers, regulatory incongruity can similarly complicate decisions to invest in production vs. seeking third-party supply. One refiner discussed how the U.S. RFS2 framework has contributed to rendering co-processing uneconomical in that country, since the U.S. regulations exclude co-processed product from qualifying for the biomass-based diesel RINs and the $1.00/gallon renewable diesel blender's tax credit[31], whereas stand-alone production of HDRD does qualify.

In some cases it has made more sense for multinational producers to locate a facility closer to a secure supply of cost-efficient feedstock and/or a location that services their distribution requirements more efficiently. For a major multinational corporation, investment decisions and strategies with respect to future renewable fuels technology are likely to be driven by the corporate body, and not necessarily optimized for the Canadian circumstances

The location of a primary supplier's operations can be a key consideration in their biofuels supply strategy. This is certainly the case for North American producers operating under Low Carbon Fuel Standard (LCFS) regulations, which exist in some form throughout most of the continental west coast. Many of the compliance decisions being made by producers in this region are considered with respect to these, more stringent regulations (with less focus on federal or provincial mandates). The BC Ministry of Energy may be forming a technical advisory

[30] European Commission (2012). Commission submits formal proposal to defer EU ETS international aviation compliance by one year. Press Release, published November 20, 2012.
[31] It does, however, qualify for Advanced Biofuel RINs.

committee of government and industry to discuss implementation issues regarding LCFS. They would also assess the viability of "transformative technology" alternatives to first-generation biofuels, for which the provincial government may provide additional incentives or carbon credits.

Capital Required for Terminal and Infrastructure Upgrades

Refiners interviewed were concerned over the significant capital already expended in order to upgrade distribution terminal blending infrastructure to accommodate the use of biofuels. The brief period between the introduction of federal and provincial renewable fuels regulations and their initial compliance periods forced the obligated parties to make significant investments that would allow them to meet their requirements within that shortened time frame. In most cases, this transition was handled through changes at the terminal level[32] and was generally built around a strategy of third-party supply since this strategy was the most flexible, scalable and least capital intensive option at the time. If refiners were to further invest in co-located production of biofuels or co-processing of renewable feedstocks at the refinery level, this would obviate the need for much of the same terminal blending infrastructure they put in place. In some cases, the refiner's initial compliance strategy has shaped, or is a consideration in their current approach.

Return on Capital

A key investment consideration is the ability to provide a reasonable return. Integrated producers likely evaluate all aspects of their business on these terms and biofuels production would not be an exception. In many cases, investments simply have not been made when there is not assured return on the capital spent. An important aspect of the required "certainty" of a return for some producers is the ability to succeed independent of government subsidies and mandates – which can be amended or eliminated over time. If the investment does not meet these criteria refiners may seek alternative approaches to meeting their renewable fuels' requirements. A refiner's capital is limited and in many cases, better returns are achieved by making those investments elsewhere in their facilities.

An alternative solution for Canada's refiners may involve the co-processing of renewables at existing refineries. This potentially offers a more scalable, flexible and less capital intensive solution that can address some of the established challenges of direct investment in Canada. This approach does present potential issues and obstacles however. The following section will address co-processing and provides a detailed SWOT analysis of its use in Canada.

CO-PROCESSING RENEWABLE FEEDSTOCKS IN CANADA

BACKGROUND

Co-processing refers to the processing of renewable feedstock such as vegetable oils, animal fats or other waste products along with traditional petroleum based feedstock using existing

[32] With the exception of some more minor changes at the refinery (to handle biodiesel and HDRD) and retail level.

petroleum refining infrastructure. The renewable component of the co-processing is sometimes referred to as “biocrude”.

Currently, the federal Regulations address co-processing in the following manner:

> *“Vegetable oils are renewable fuel feedstocks from which a liquid renewable fuel can be produced. Hydrotreated vegetable oil would be considered to be a renewable fuel for the purposes of these regulations, provided it complies with the maximum content of non-renewable substances, and otherwise meets the definition of "renewable fuel". If used as a feedstock at a petroleum refinery, vegetable oil would be considered to be a biocrude for the purposes of these regulations provided it meets the definition of biocrude.”*[33]

Triglyceride–derived biocrude creates 17 distillate compliance units for each 20 litres of biocrude used. Using any biocrude other than triglyceride-derived creates one gasoline and one distillate CU for every 5 litres of biocrude used. From Environment Canada:

> *“The ratios for the two types of biocrude were developed in consultation with the Industry Technical Advisory Group. The ratios set out in the regulations were generally agreed upon by that group based on information that was available at the time. If more information becomes available in the future on the use and yields of biocrude, these ratios might be adjusted through amendments to the regulations.*
>
> *Because of the nature of triglyceride-derived biocrude and refinery processes, current information suggests that most of this type of biocrude will end up in distillate products. This biocrude also has fewer yield losses. Consequently, the use of this type of biocrude creates 17 distillate compliance units for each 20 litres of biocrude used, but does not create any gasoline compliance units.”*[34]

Provincially, co-processing is not addressed specifically; however it may get consideration by British Columbia in the context of their LCFS requirements.

There are sensitivities in U.S. regulations surrounding co-processing. Their biomass-based diesel standard excludes any production that is co-processed with petroleum feedstock. The impetus behind their regulatory treatment of co-processed renewable diesel comes partly from strong opposition from biofuels interest groups[35]. The position of these interest groups is that renewable fuel produced from the co-processing of renewable and conventional petroleum feedstock should not qualify for the renewable diesel excise tax credit or biomass based diesel RINs. They view it as a subsidization of existing refining operations at the expense of stand-alone biodiesel producers[36].

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[33] Environment Canada Website: “Revised Q & A on the Federal Renewable Fuels Regulations”, General Questions.
[34] Environment Canada Website: “Revised Q & A on the Federal Renewable Fuels Regulations”, Part 2 – Compliance Unit Trading System.
[35] Such as the National Biodiesel Board.
[36] National Biodiesel Board. “ Biodiesel, Renewable Diesel and Co-Processed Renewable Diesel” . 2009

SWOT ANALYSIS

Graphic 1: SWOT Matrix for Co-Processing

S	**- Synergy through the use of existing refining infrastructure** -Scalability / Flexibility -Cost reduction through resource pooling -Quality of products	W	**- Impact on existing refinery yields, production and / or infrastructure** -Return on Capital
O	**- External factors affecting potential for Return on Capital (feedstock costs, feedstock availability, sale of co-products)** -Favourable regulatory developments -Technological innovation	T	**- Regulatory Instability** -The "accounting" of inputs, outputs and awarding of Compliance Units. -Other potentially unfavourable regulatory developments

Strengths

There are several advantages to co-processing renewable feedstock with conventional petroleum feedstock. The most prominent of which is likely the synergy realized by refiners when they are able to capitalize spare capacity from existing refining facilities in order to produce renewable alternatives alongside conventional fuels. With refinery utilization throughout North America declining over the last five years there is, on average, a growing capacity at existing facilities to potentially process biofuel requirements. **Figure 2** shows how the growing requirement for advanced biofuels in the U.S. could be accommodated by existing spare capacity at refineries. The Canadian scenario is similar with respect to the presence of some spare refining capacity. Utilization rates at Canadian refineries averaged 85 percent in 2011 and have averaged roughly 90 percent since 2008[37].

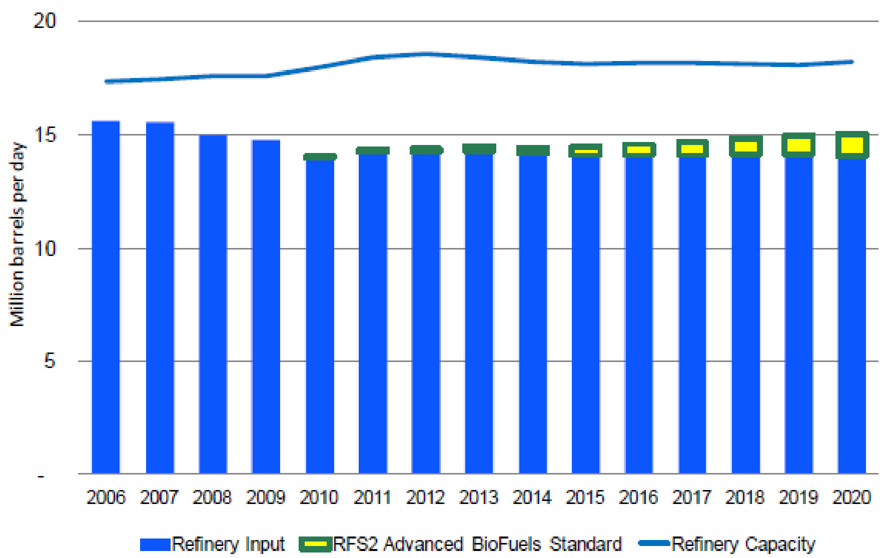
This approach is much less capital intensive than building standalone facilities and allows for a more scalable and flexible solution as production can be adjusted or the blending optimized to suit a company's strategic needs. This type of scalability and flexibility is not necessarily an option when building large stand-alone facility that requires consistently high utilization to provide a financial return. There is some capital requirement with a co-processing approach but it is limited in relation to standalone facilities and would typically include equipment to accommodate the receipt, storage and delivery of feedstock, and possible pre-treatment

[37] BP Statistical Review of World Energy 2009 - 2012.

facilities. The more expensive facilities used in the production process (such as hydrotreatment, and catalytic crackers) would already be in place.

Another advantage is the potential of cost-reduction through resource pooling. For example, integrated processing can share costs for labour and utilities where these would be redundant costs with a stand-alone approach.

Figure 2: U.S. Refinery Utilization and RFS2 Advanced Biofuel Standard



Source: EIA Annual Energy Outlook 2010

As mentioned, the flexibility of blending optimization in a conventional refining facility allow for better handling of the potential by-products than a standalone facility. For instance, in a co-processing trial performed by a refiner, a particular renewable feedstock's output was primarily propane and naphtha. In a stand-alone facility these outputs would have to be dealt with in isolation but in an integrated refinery the outputs can be used as blending components (such as naphtha being an excellent gasoline blendstock), or as feedstock for other refinery processes. Co-processing may also allow more flexibility in terms of the type of crude feedstock used at the refinery. One refiner identified the potential ability to process heavier crudes when introducing renewable feedstock into their facility. The output properties of some types of co-processed HDRD[38] can allow for optimized blending of heavier lower value refinery streams into the diesel pool, thus improving product yields and potentially increasing margins[39].

In the case of co-processing HDRD, the quality of the fuel is considered a strength. It has already been established that HDRD is the preferable choice to meet compliance of diesel mandates in Canada because of its superior cold weather properties. Co-processing HDRD allows producers to produce "drop-in" quality renewable fuel without investing in large stand-

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[38] Higher cetane, lower density and other properties similar to conventional diesel.
[39] UOP Hydrorefining Tech Paper. "Diesel production by hydrorefining renewable feedstocks". Jan 2013.

alone production facilities or paying significant premiums to import foreign-sourced HDRD. It's "drop-in" quality also makes it suitable for use with existing refined product distribution infrastructure.

Weaknesses

The potential of co-processing was generally viewed with scepticism when discussed with Canadian refiners. Although there is less capital intensity with this production pathway, there can still be significant investments required to facilitate co-processing – most notably on the front end in areas such as pre-treatment, storage, and the potential need for additional hydrogen generation capacity.

A primary weakness with co-processing is the potential impacts it can have on the existing refining infrastructure and yields of conventional petroleum based production. Its introduction into the production stream can create potential issues with contaminants and by-products (such as oxygen, phenol etc.) that need to be addressed either in pre-treatment phases, or in the case of phenol, can pose problems with processes like wastewater treatment. In some cases, the introduction of renewable feedstock can alter the operating conditions of a specific unit, requiring the introduction of specialized catalysts or altering the function of existing catalysts in the process. Introduction of specialized catalysts require that they be dealt with later in the process stream and can further alter process operating conditions and yields.

Co-processed blends above 10 percent renewable content have for the most part, been limited to demonstration or laboratory scale activity under optimized conditions. In terms of commercial scale activity to achieve higher blends there were concerns expressed over the impact on existing petroleum production and yields, or the need for significant pre-treatment of the feedstock - which would increase the capital intensity of the approach[40]. There has been very little commercialization of co-processing operations even at blends below 10 percent. The level of blending that introduces undue risk is unique to each facility; some facilities can tolerate higher blends of co-processed material without introducing significant risk while others could not tolerate the introduction of even small amounts of renewable feedstock.

Another potential weakness for co-processing is the return on capital employed. Several refiners expressed that their investigations into the use of co-processing revealed the potential for a financial return that was not considered viable. Both, high feedstock costs and renewable feedstock yields that are disproportionate with how CUs are awarded for co-processing could negatively impact returns, making co-processing uneconomical relative to other compliance options.

Opportunities

Despite the fact that poor return on capital could be considered a weakness of the co-processing approach, there is also opportunity in the potential for increased return on capital employed. There are several external factors that can have a significant impact on the profitability of co-processing operations. Feedstock prices are a particularly important factor considering the large portion of operating costs that they account for. Currently, feedstock

[40] BIOCOUP: Co-processing of upgraded bio-liquids in standard refinery units. 2011

choices, and their respective prices are fundamentally correlated with the profitability of an operation. If there are significant decreases in feedstock costs or an inexpensive feedstock option becomes more readily available to North American producers, this could lead to a dramatic shift in the financial viability of co-processing operations.

Another factor that could potentially improve the return for co-processing in Canada is the market for higher value co-products. Various pre-treatment and production pathways using a range of feedstocks can result in an array of co-products. While some of the co-products produced are undesirable, there is the opportunity to find markets for co-products to increase the revenue potential of co-processing. In some cases, finding "high-value" co-products differentiates profitable operations from those that are not, similar to the recovery and sale of distillers' grains and corn oil[41] and its impact on margins for ethanol producers.

Another external factor that may affect the success of co-processing operations is the prospect of favourable regulatory developments. This could include modifications to the existing mandates, and subsidies or adjustments to the formulae by which CUs are awarded for co-processing. These changes could dramatically affect biofuels markets and under some circumstances provide incentive to pursue direct investment in biofuels production strategies such as co-processing.

Technological innovations are a significant variable in the development of biofuels production. Advancements could come in the form of feedstock innovation, catalyst technology, the development of new pre-treatment processes or other process innovation. There is the potential for "game changing" innovation that improves the likely success of the co-processing approach. Globally investments are being made by both traditional and non-traditional petroleum producers into research and development for co-processing technology. Their efforts to improve product yields, increase acceptable blend rates and optimize operational efficiency could have significant long-term impacts on the viability of co-processing.

Threats

Regulatory developments could also be viewed as a threat to co-processing because of their potential to impact biofuels markets. The success of long-term investments into a particular biofuels strategy can, in some cases, depend on regulatory stability. Changes to policy can create inefficiencies in biofuels markets or result in an "unlevel playing field" for specific approaches to biofuels production. Ultimately these changes can inhibit investment and hinder the success of a co-processing operation.

The viability of co-processing could also be threatened by the disparity between federal and provincial renewable fuels regulations. While the use of co-processing is addressed clearly by federal regulations, there are concerns over the clarity of British Columbia regulations with respect to defining the requirements of co-processing at an integrated facility and how it impacts other regulations such as the LCFS.

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[41] By-products of the ethanol production process.

There is also concern among refiners over the “accounting” of co-processed material which includes the inputs, outputs, the federal CU awarded, and the impact the current regulatory framework - both in the U.S. and Canada- has on the financial viability of co-processing. Some refiners have concerns about the yields obtained from co-processed material and whether this is commensurate with the way CUs are awarded in Canada. Any misalignment with regard to the awarding of CUs for co-processing can affect the financial viability of this approach and potentially motivate a refiner to alter their biofuels compliance strategy.

CONCLUSIONS

Our discussions with primary suppliers in Canada yielded a diversity of views towards investments in the production of renewable alternatives to gasoline, diesel and other fuels. This diversity of views, as well as those common elements that emerged from our discussions formed the basis for our conclusions. Canada’s primary suppliers assess their potential investments against a common set of criteria including – the security of supply, cost reduction generated by the introduction of some form of synergy, and an assured return on capital.

The Canadian ethanol market is well supplied and there is little synergy to be gained from incorporating ethanol production into existing conventional fuel production infrastructure. Third-party supply of ethanol is the most commonly pursued strategy for gasoline compliance because of its cost effectiveness and efficiency. Margins in the ethanol industry have faced significant pressure and under current market conditions[42], a return on capital would not be assured. Under specific circumstances, an opportunity to acquire undervalued assets or to meet a specific strategic need may materialize, and this could shift a specific producer’s perspective.

The supply market for renewable alternatives to diesel was viewed as underutilized and the security of their supply was not a primary concern; however, this may be changing as the international market for HDRD gets more competitive. While there is the potential for some synergy with the co-location of renewable diesel production, the amount of capital required to build a facility large enough to take advantage of economies of scale is prohibitive. This is further complicated by the relative size of the Canadian renewable diesel market, which would likely result in a large portion of a new facility’s production being destined for export. Additionally, the availability and cost of North American feedstocks could lead to supply concerns and challenge the profitability of a renewable diesel operation.

Co-processing of renewable feedstock with conventional petroleum feedstock can provide a synergistic benefit to producers, thereby offering a more scalable and flexible option relative to standalone production. Co-processing raises concern over the potential impact on current yields however, as well as concerns over impacts on the operating environment of conventional production. There is also uncertainty over the profitability of a co-processing operation, specifically as it relates to the “accounting” of inputs, outputs and the rate at which compliance units are applied.

[42] A prolonged period of low ethanol prices and high feedstock prices.

Global investment in biofuels research, development and production is robust and growing; however, this is not necessarily represented among Canada’s primary suppliers. Many multinational petroleum suppliers operating in Canada are choosing to make their strategic investments elsewhere. Their motivations include regulatory uncertainty, feedstock issues, the dynamics of Canadian biofuels markets, and domestic facilities’ access to export markets.

Domestic petroleum producers expressed their intentions to continue to evaluate opportunities for strategic investment in biofuels, although their evaluations will likely be based on similar criteria to those discussed in this report. An assessment of the current market opportunities and investment environment for petroleum producers in Canada points to limited near-term growth in direct investment into renewable fuels production.

Appendix A | Professional Resumes

Michael J Ervin

Mr. Ervin is the Principal of MJ Ervin & Associates, a division of Ontario-based The Kent Group. He has had a successful and varied career in the downstream petroleum industry spanning over thirty years. Management assignments have taken him to all regions of Canada, working with major integrated oil companies as well as regional refiners and marketers. In his subsequent petroleum consulting career of twenty years, he has worked with industry and government clients from across North America, Europe and Africa. Mr. Ervin's functional specialties include petroleum marketing economics, downstream operations management and reviews, feasibility studies, and petroleum marketing strategy and planning. Mr. Ervin is a well-known media commentator on matters relating to the petroleum industry, especially on the subject of retail fuel prices. His reputation for insightful, impartial and clear analysis of petroleum industry issues has led to many speaking engagements and appearances at a number of industry and public forums dealing with the downstream sector.

In addition to his consulting practice, Mr. Ervin is a serving officer in the Canadian Forces Reserve. He is a Commissioner on the Calgary Police Commission, and a director on the board of the Canadian Association of Police Boards. He is an avid runner, and has completed over 18 marathons, including the 2006 Boston Marathon. Mr. Ervin is a private pilot, and with his wife Martina, enjoys downhill and cross-country skiing, and summer hiking and backpacking.

Mr. Ervin's range of expertise within the downstream sector includes:

- Competitiveness factors relating to petroleum wholesale and retail marketing, as well as at the commodity (spot/rack market) level;
- Industry infrastructure related to the refining, transportation, storage, and marketing of petroleum products;
- Regulatory issues relating to all aspects of petroleum operations, including price regulatory structures;
- Performance benchmarks for petroleum marketers;
- Comprehensive indoctrination and familiarization training to organizations involved in the downstream sector;
- Market dynamics relating to petroleum supply, demand and price, including the influence of crude, wholesale and local retail competitiveness factors.

Jason Parent

Mr. Parent is a Senior Associate at The Kent Group. His responsibilities encompass a range of project management roles, as well as the analysis and reporting of data for a variety of client requirements.

Mr. Parent has 11 years of experience in providing consulting and performance data and analysis relating to the petroleum industry. His industry expertise is augmented by an undergraduate degree, having graduated with distinction in Business Administration. Jason plays a vital role in the management of relationships with The Kent Group's extensive client base, meeting their needs in a diverse range of services including consulting and custom project work, development of custom data delivery and reporting, as well as assisting clients in the development of project needs and deliverables.

Mr. Parent has played a key role in an extensive and diverse list of downstream petroleum consulting projects, focused specifically in the areas of regulatory analysis, market and price analysis, forecasting and performance benchmarking. Project work includes:

- A detailed assessment of the impact of the introduction of federal renewable fuel standards on an existing provincial price regulatory framework. Considering both, the validity and viability of the regulatory framework under these unique market conditions, the report clearly laid out a plan for the province to proceed.
- A forecast of wholesale fuel prices in the short to medium term. A conceptual framework for wholesale pricing was established and used to construct a comprehensive analysis and forecast.
- Conducted detailed market analysis studies for several clients in a variety of contexts.

In addition, Mr. Parent manages The Kent Group’s involvement in the collection and reporting of national retail fuel pricing information for Natural Resources Canada.

Appendix B | Discussion Outline

Preamble

- Canada, the U.S, the E.U., and other countries have established mandates for renewable content in transportation fuels. This has spurred the development of biofuels industries globally, and some refiners have identified an opportunity to participate in producing these fuels. For example:
    - Husky and Suncor own about one-third of ethanol production capacity in Canada, and Shell is an investor in Iogen.
    - Valero is the third largest ethanol producer in the U.S.
    - Shell signed a $12 billion joint-venture with Cosan in Brazil to produce cellulosic ethanol.
    - Neste Oil is the largest producer of hydrogenation derived renewable diesel in the world
- While these examples illustrate that some primary suppliers (mostly refiners) have directly invested in biofuel R&D and/or production, others have not. This is suggestive of a range of views with respect to the risks and rewards of doing so.
- NRCan wishes to understand the approaches taken by Canadian refiners towards engagement in the biofuels production sector, and have engaged MJEA to assist in this regard.
- The purpose of this project is to assess if refiners in Canada are looking at further engaging in the biofuels market by producing renewable alternatives to gasoline, diesel, and jet fuel, and what is driving their decisions.
    - Are refiners looking to integrate biofuels production with petroleum fuels production?
    - Have they assessed the opportunities in and outside of North America for these fuels?
    - Quote from Peter Boag, President of Canadian Fuels Association:

Biofuels are already a small but growing segment of the fuels market, largely driven by provincial and now federal mandates. Canadian Fuels Association members include some of the largest biofuels producers in Canada – companies that are CRFA members as well as members of Canadian Fuels. They see a growing role for biofuels in the overall transportation fuel mix. In 2006, our Association, together with CRFA, endorsed the federal initiative to implement a national renewable fuel standard for both ethanol and renewable diesel. Our members were leaders in much of the testing, analysis and demonstration pilots that informed implementation of the federal mandate. ***Today they, or their corporate parents, remain at the forefront of research, development and innovation in next generation biofuels.***

Review of Refining Facilities

- General overview of annual production throughputs of Gasoline, Diesel, Jet
- Associated terminals
    - To what extent is location or distance from the refinery a factor?
    - Is mode of distribution a consideration?
    - What considerations have gone into the decisions as to whether to configure a given terminal as a "conventional" (i.e. not blending in biofuels) terminal versus one that mainly blends and supplies biofuels blends?
    - Has the proximity of biofuels suppliers to terminals (as opposed to the refinery) been a consideration as to produce biofuels directly instead of via third parties?
- Jet fuel production
    - Do you currently integrate biofuels into its production or sale of Jet fuel?

Direct Interest in Biofuels Production

- Arms-length Investment e.g. partnership, minority interest
    - Percentage of total biofuels procurement
- Direct asset investment/operation
    - Facility description (location, product(s), client terminals)
    - Percentage of total biofuels procurement
    - Percentage of production for export
- Rationale (opportunities/threats/risks)for or against direct investment
    - Return on capital employed
    - Market opportunities
    - Synergies/efficiencies created (describe): logistical, cost,
    - Other
- In the case of multi-nationals:
    - Where there has been a difference in first-party biofuels production strategy in foreign operations vs Canada, what considerations have factored into that approach?
- Experience to date with respect to initial rationale (if directly invested)
    - Strengths/successes
    - Weaknesses/shortfalls
- Future outlook for direct investment (with respect to opportunity and risk factors)
    - Export opportunities
    - Return on capital employed / margins
    - Synergies/efficiencies
    - Renewables mandates and government incentives
    - Other
- Integration of biofuels production into refining facilities
    - Has there been any consideration towards processing renewable fuel feedstock e.g. canola oil through existing refinery processing units to produce a form of "drop-in" fuel?

- If so, what have been the results?
- If not, what has been the rationale against doing so?