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Debottlenecking a Delayed Coker to improve overall Liquid Yield and Selectivity towards Diesel Fuel

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ABSTRACT

As crude oil and product prices continue to climb, there is an economic incentive for refineries to increase overall distillate yield with increased selectivity towards diesel fuel. This paper discusses the pros and cons of simply adding a new delayed coker versus a residue hydrocracker upstream of an existing delayed coker to improve overall liquid yield and selectivity towards diesel fuel. Commercial examples will be presented along with the economics of the two approaches.

INTRODUCTION

The United States has the greatest concentration of Delayed Cokers of any market in the World. Of the 130 refineries processing 17.8 million bpd of crude oil, 60 of these refineries use Delayed Coking to destroy the vacuum residue and increase the yield of distillates for further processing into transportation fuels.

The first Delayed Coker came on-line in 1929 at the Standard Oil of Indiana refinery located in Whiting, IN. At that time, crude oil was selling for $1.27/bbl in current dollars. Since that time our industry has gone through various economic cycles. The most recent cycle started in 2000 with a consistent rise in the price of crude oil which is today about $100/bbl for WTI. In addition, two major shifts have also occurred in our market; natural gas prices started to fall in 2008 due to new discoveries in natural gas and the gasoline to diesel margin reversed in 2005 where diesel is now priced higher than gasoline.

As a result of these shifts in the marketplace, Axens decided to re-examine a prior study to see how these shifts might influence a refinery's decision on how to best process additional crude capacity through a refinery expansion.

USA MARKET FOR DELAYED COKING

In 2010, the USA had 60 Delayed Cokers compared to 11 in Europe, 4 in the Middle East and 27 in the Far East. Clearly this was the preferred choice for destroying the vacuum residue from medium and heavy crude oil in the USA market. Of the 60 Delayed Coking Units in the USA, 55% in terms of capacity are located in PADD 3 (US Gulf Coast) and 13% are located in the PADD 2 market (Midwest).

Delayed Coker at Husky's Lloydminster Upgrader

The vast majority of these Delayed Coking Units were installed when crude oil was below $20/bbl. In the last 10 years, Brent and WTI prices have continued to rise at an unprecedented rate.

OPTIONS FOR A REFINERY EXPANSION

Historically, refineries have added incremental Delayed Coking capacity as part of refinery expansions because it was considered to be low investment cost, well known and economically attractive. But with the new changes in market prices and the increase in residue hydrocracking worldwide, it begs the question; is this still the best option for a USA refinery?

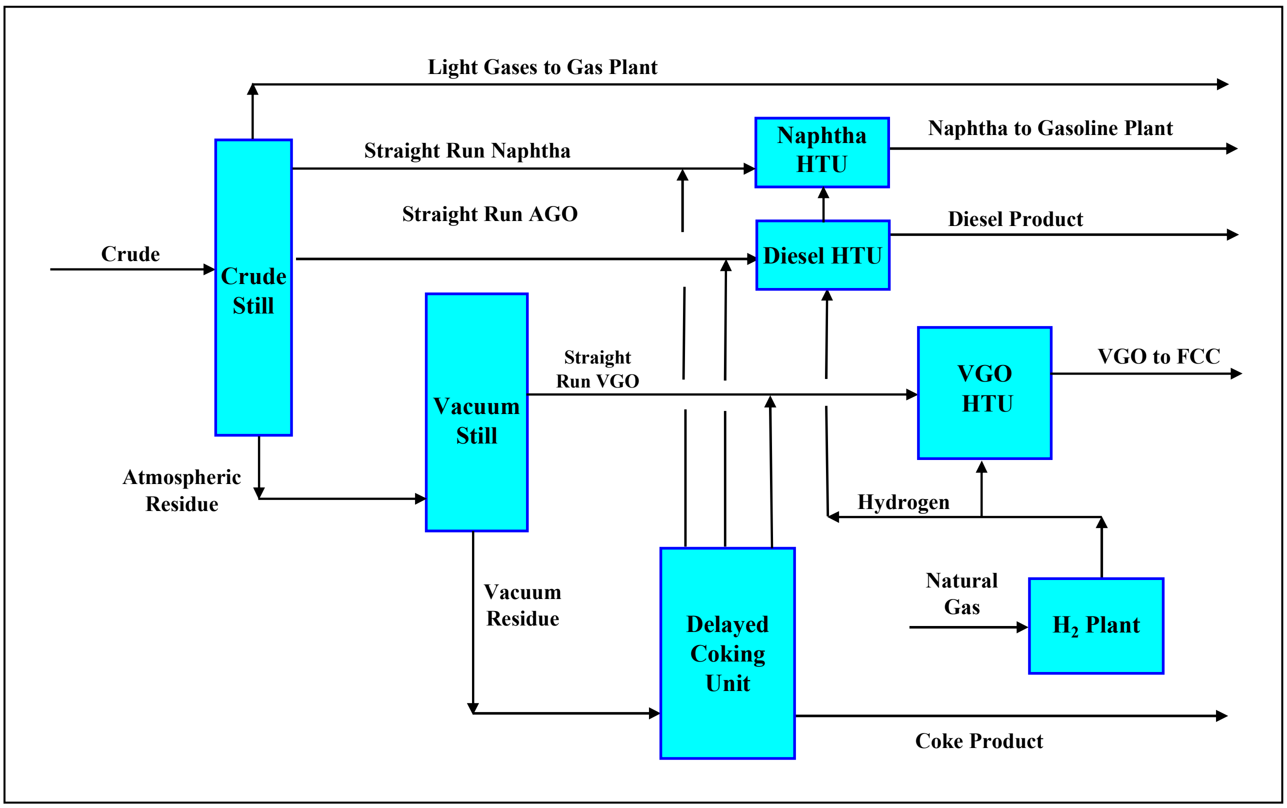
Axens has studied an existing 100,000 bpsd refinery processing 100% Arabian Heavy crude. Expansion studies were conducted using both Arabian Heavy crude and Athabasca Bitumen with properties shown in Table 1.

Table 1 Crude Properties

Property	Arab Heavy	Athabasca Bitumen
°API	27.0	8.4
Sulfur, wt%	2.85	4.92
Nitrogen, wt ppm	1,680	3,900
Ni + V, wt ppm	75	325
CCR, wt%	7.9	13.5
C_7 Asphaltenes, wt%	2.5	9.5
Distillation, wt%		
IBP – 350 °F	15.0	-
350 – 650 °F	23.6	12.8
650 – 975 °F	27.9	28.6
975 °F+	31.9	58.6

The front end section of a typical refinery configuration is shown in Exhibit 1 which utilizes a Delayed Coker for processing the entire vacuum residue. Straight run and Delayed Coker distillates are processed in naphtha, diesel and FCC feed pre-treat hydrotreaters. Steam-methane reforming is used for the generation of hydrogen for this study.

Exhibit 1 100,000 bpsd Existing Refinery



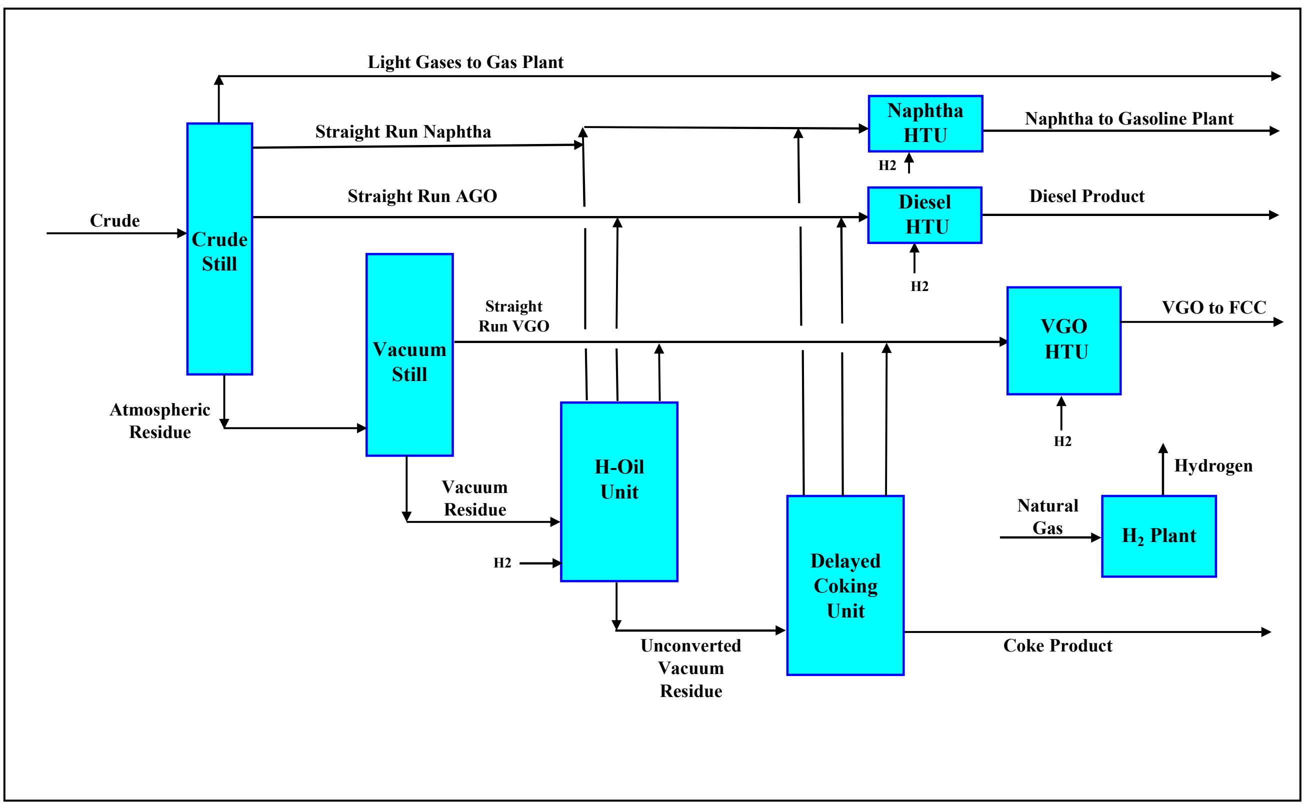
Two expansion configurations were investigated for this study. The first case (Case 1) adds an additional 100,000 bpsd of Arabian Heavy Crude and duplicates the existing 27,200 bpsd Delayed Coker. The expansion brings the total crude throughput to 200,000 bpsd. The battery limits of Axens study is shown in Exhibit 1 and includes the associated offsite and utilities. It does not include the FCC Unit or the post FCC hydrotreater (i.e. Prime G+).

The second case (Case 2) adds a 54,400 bpsd H-Oil® $_{RC}$ Unit (residue hydrocracker) ahead of the existing Delayed Coker which remains untouched as shown in Exhibit 2. The H-Oil® $_{RC}$ Unit is a single train plant with a single reactor operating at 60% conversion of the 975 ºF+ residue to distillates. Axens also investigated a variation to this case (Case 2A) where the conversion level is increased to 70% and the crude throughput is increased to 300,000 bpsd in order to fill up the existing Delayed Coking Unit.

To handle the increased feed rate and reactor severity for Case 2A, the number of reactors is increased to two in series with inter-stage separation for this single train plant. With the higher conversion level in the H-Oil®$_{RC}$ Unit, the total Arab Heavy crude capacity was increased to 300,000 bpsd and the existing Delayed Coking Unit is still capable of processing the entire unconverted vacuum residue from the H-Oil®$_{RC}$ Unit.

The final case (Case 3) examines the effect of switching from Arab Heavy Crude to Athabasca Bitumen (DilBit). This is a variation of Case 2 (see Exhibit 2) with the addition of a residue hydrocracker ahead of the existing Delayed Coking Unit. Due to the high vacuum residue content in the crude, the crude rate to the refinery is only increased from 100,000 bpsd to 150,000 bpsd. In all cases, the product streams (naphtha, diesel and vacuum gas oil) are treated to the same level of product quality.

Exhibit 2 H-Oil®$_{RC}$ / Delayed Coking Expansion Case



ECONOMIC BASIS

For this updated study, Axens examined pricing data from the U.S. Energy Information Agency (EIA) for the USA as a whole and also for the PADD 2 (Mid West market) and PADD 3 (Gulf Coast market).

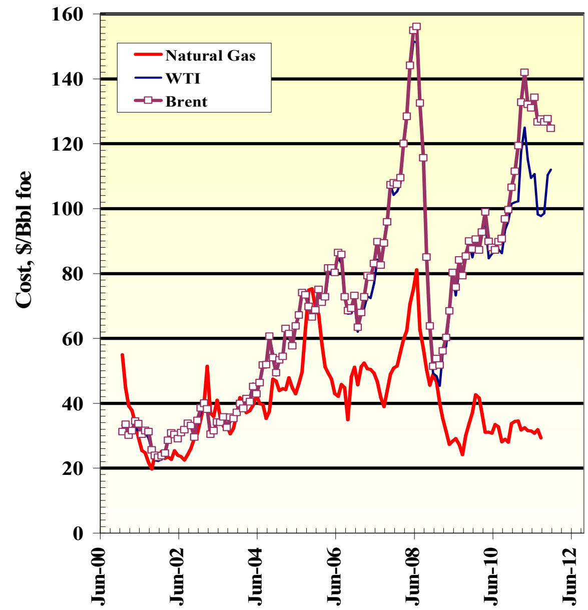


Figure 1 Crude & Nat'l Gas Price over Time

The US prices for Brent, WTI and industrial natural gas are shown for the last ten years in Figure 1. Brent and WTI have tracked fairly close to each other except for the last couple of years. The prices for DilBit (Athabasca Bitumen) can be calculated from Western Canadian Select "WCS" synthetic crude which is traded in Chicago. There is a weak correlation between Brent and WCS prices but a strong correlation when the natural gas condensate (diluent) is removed from the WCS. To calculate the actual price of the bitumen, the cost of natural gas condensate is removed from the DilBit resulting in an average net price of the Athabasca Bitumen of $68/bbl when Brent crude is valued at $100/bbl. This bitumen price is the same price as Hardisty Heavy Bitumen (12 °API) of $68.35 quoted in the January 2012 issue of the Oil Sands Review.

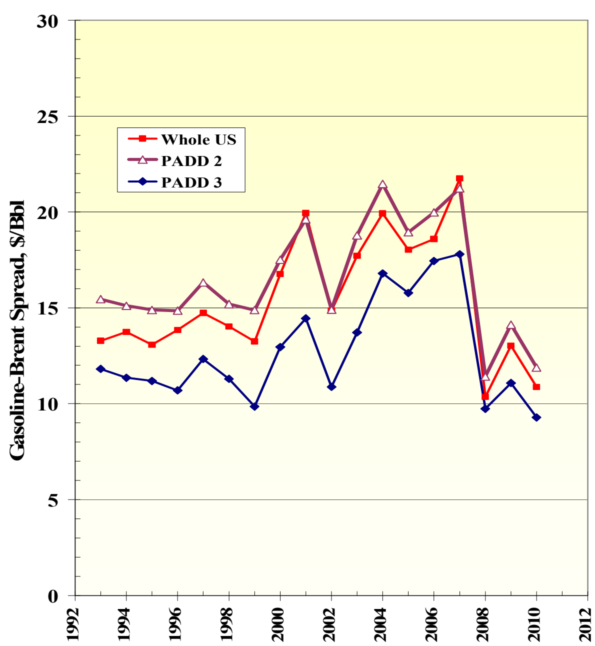


Figure 2 Gasoline-Brent Price over Time

Brent crude is used as benchmark crude for this study to determine gasoline and diesel margins based on historical trends. Natural gas prices increased from 2002 to 2005 due to a large demand and a shortage of supply as seen in Figure 1. However, in 2006 the production of additional natural gas came on the market with some originating from the tight shale gas formations which started a downward trend in natural gas prices. Recently, the average US industrial natural gas price has been in the range of \$4.00 to \$5.00 per thousand standard cubic feet or roughly \$30 per barrel (foe basis).

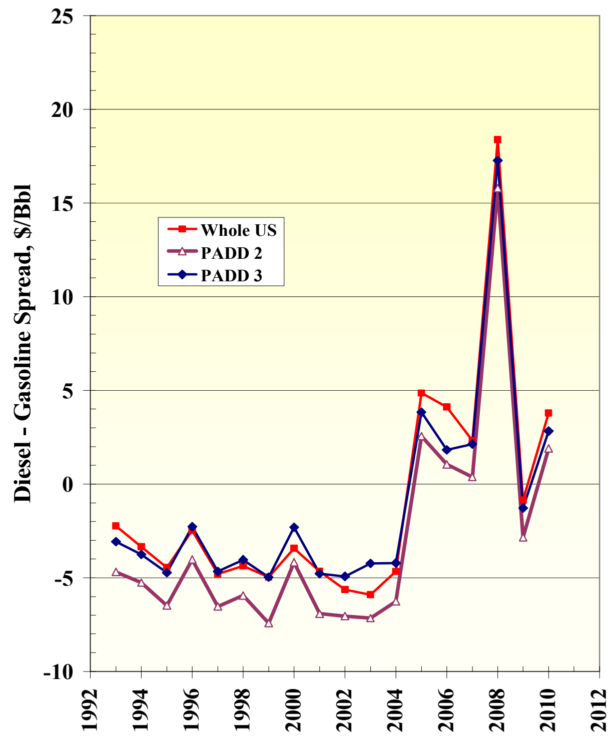


Figure 3 Diesel-Gasoline Price over Time

The Gasoline to Brent price spread (Gasoline price minus Brent crude price) is shown in Figure 2 and reflects a general increase in gasoline margins from 2000 to 2007 and then a steady decrease thereafter. No doubt the importation of gasoline from Europe and the increase in ethanol into the USA gasoline pool is resulting in a decreased domestic demand for this fuel. For the last 3+ years, the PADD 2 prices have been higher than the average US prices while the PADD 3 prices have been lower than the national average. The Diesel to Gasoline margin over the same time period is shown in Figure 3. For this study a price spread of \$9/bbl was used for gasoline to Brent crude (based on 2009-2011 prices) which equates to \$109/bbl for gasoline when Brent crude is valued at \$100/bbl for the average US market. Slightly higher prices could be used for projects in the PADD 2 based on these historical trends.

The price of diesel fuel overcame the price of gasoline in 2005 and has continued to stay higher than gasoline for the last 6 years. Consequently there is more interest from refiners to increase diesel production by any means possible. This would imply an increase in mild and full conversion hydrocracking in the future.

Based upon the examination of the previously mentioned trends, Axens utilized the economic basis shown in Table 2.

Table 2 Economic Basis

Item	Units	Value
Operating Days per Year	Days	345
Offsites & Utilities Cost	% of Process Units	50
Investment Contingency	%	20
Natural Gas Cost	$/KSCF	5.00
Sulfur Product Credit	$/MT	20
Coke Product Credit	$/MT	10
Arabian Heavy Crude Price	$/Bbl	92.48
Net Bitumen Cost	$/Bbl	67.85
Brent Crude Ref. Price	$/Bbl	100
LPG Price	$/Bbl	61
Gasoline Price	$/Bbl	109
Diesel Price	$/Bbl	114
VGO (FCC feed) Price	$/Bbl	105

Note: Reflects prices assumed by Axens and represents typical values in the marketplace during the period of 2009 to 2011 as reported by the US Energy Information Agency and by Natural Resources Canada.

DESCRIPTION OF THE CASES

A summary of the 4 expansion cases investigated are described below. The cases are:

Case 1 Add 100,000 bpsd of Arabian Heavy crude to the existing refinery using Delayed Coking as the residue conversion unit.

Case 2 Add 100,000 bpsd of Arabian Heavy crude and add a H-Oil®$_{RC}$ Unit operating at 60 % vacuum residue conversion ahead of the existing Delayed Coker.

Case 2A Same as Case 2 with the H-Oil®$_{RC}$ Unit operating at 70 % vacuum residue conversion and crude throughput increased by 200,000 bpsd.

Case 3 Add 50,000 bpsd to the existing refinery and switch from Arabian Heavy to Athabasca Bitumen. In this case, an H-Oil®$_{RC}$ Unit is added ahead of the existing Delayed Coking Unit.

In all of the cases evaluated, the straight run and cracked products are hydrotreated to meet the product specifications shown in Table 3 below.

Table 3 Product Specifications

Item	Unit	Naphtha	Diesel	VGO
Sulfur	wt ppm	0.5 max	10 max	2000 max
Nitrogen	wt ppm	0.5 max	-	
Cetane No.			40 min	

Expansion Case 1 (Delayed Coker)

The existing refinery crude capacity was doubled to 200,000 bpsd with Arabian Heavy crude. The total vacuum residue feed rate to the Delayed Coker is 54,400 bpsd. The new Coker is a duplicate of the existing Unit. The C_5 + product yield from the Delayed Coker is 66 vol. %. This product is then blended with the straight run distillates and hydrotreated to meet the product specifications shown in Table 3. The overall liquid yield was 180,500 bpsd or 90.3 vol. % on crude throughput which includes LPG, naphtha, diesel and vacuum gas oil. The VGO is assumed to be routed to an FCC Unit which has a post hydrotreater and can therefore meet Tier 3 gasoline specifications. A breakdown of the yields is shown in Table 4.

Expansion Case 2 (H-Oil®$_{RC}$ Residue Hydrocracking)

As in Case 1, the overall refinery throughput is doubled to 200,000 bpsd and all of the vacuum residue (54,400 bpsd) is routed to a single train, single reactor H-Oil®$_{RC}$ Unit operating at 60% vacuum residue conversion. The unconverted residue (21,922 bpsd) is sent to the existing Delayed Coking Unit with a nameplate capacity of 27,200 bpsd. The overall yields from the H-Oil®$_{RC}$ Unit, the downstream Delayed Coker and hydrotreaters are shown in Table 4. All of the straight run, H-Oil® and coker distillates are hydrotreated to meet the product quality specifications shown in Table 3. The overall liquid yield was 192,600 bpsd or 96.3 vol. % on crude throughput which includes LPG, naphtha, diesel and vacuum gas oil which is routed to an FCC Unit.

H-Oil® Reactor – courtesy of Husky Energy

This case is very similar to the commercial H-Oil$^{®}_{RC}$ /Delayed Coking Unit operating at Husky Energy's Lloydminster Upgrader in Saskatchewan, Canada. The feed to this H-Oil$^{®}_{RC}$ Unit is about 34,000 bpsd of a blend Cold Lake/Lloydminster heavy residue and operates around 60% conversion. The entire unconverted residue from the H-Oil$^{®}_{RC}$ Unit is routed to Delayed Coking for making fuel grade coke for export.

<u>Expansion Case 2A (H-Oil Residue Hydrocracking)</u>

In this case, the H-Oil$^{®}_{RC}$ Unit conversion level is increased from 60% to 70% and the number of reactors is increased to two in series with inter-stage separation but still in a single train. The larger reactor volume is required due to the increase in feed rate and reactor severity. With the increase in conversion, the refinery throughput can be increased to 300,000 bpsd which results in a feed rate of 81,655 bpsd to the H-Oil$^{®}_{RC}$ Unit and the unconverted bottoms (24,503 bpsd) is routed to the existing Delayed Coker Unit. The yields for this case are shown in Table 4 for the H-Oil$^{®}_{RC}$ and Delayed Coker Units. As before, all of the distillate straight run and H-Oil$^{®}_{RC}$ / Delayed Coker products are hydrotreated. The overall liquid yield is 292,300 bpsd or 97.4 vol. % on crude throughput.

<u>Expansion Case 3 (H-Oil$^{®}_{RC}$ / Delayed Coking processing DilBit)</u>

In this case, the type of crude is switched from Arabian Heavy to a Canadian DilBit based on Athabasca Bitumen. The feed rate to the refinery is expanded to only 150,000 bpsd of Athabasca Bitumen (excludes the diluent which is recovered and returned to Canada). The total feed rate to the diluent recovery unit is 216,900 bpsd and contains about 31 vol. % of diluent. The relatively small increase in throughput is due to the high content of vacuum residue in the feed (58.6 vol. % versus 31.9 vol. % for Arab Heavy). The feed rate to the H-Oil$^{®}_{RC}$ Unit is 83,754 bpsd and the feed rate to the Delayed Coker is 27,221 bpsd. In this case the H-Oil$^{®}$ Unit is a single train with two reactors in series with inter-stage separation and operating at 68% conversion.

Table 4 Product Yields

	Case 1	Case 2	Case 2A	Case 3
Feed Type	Arabian Heavy			Athabasca Bitumen
Configuration	DC	H-Oil®/DC	H-Oil®/DC	H-Oil®/DC
H-Oil Conversion		60%	70%	68%
Yields, vol% on Crude				
LPG	1.81	1.79	1.20	1.49
Naphtha	24.73	25.32	25.20	14.06
Diesel	32.16	34.78	35.27	36.45
VGO	31.56	34.40	35.18	49.54
Total	90.26	96.29	96.86	101.53
Coke yield, MT/day	3,114	1,431	1,706	1,647
H_2, SCF/bbl of crude *	490	800	875	1,840

Note: DC = Delayed Coking,
* includes H-Oil®$_{RC}$ Unit and/or DC Unit plus all three distillate hydrotreaters

STUDY RESULTS

A summary of the cases processing Arabian Heavy crude is shown above in Table 4. Axens designed the three hydrotreaters (naphtha, diesel and VGO) Units based on its NHT (Naphtha Hydrotreating), Prime D and CFHT (Cat Feed Hydrotreating) technologies. The most severe design conditions were associated with the cases processing the greatest percentage of cracked stocks and the highly aromatic bitumen feedstock. Catalyst cycle lengths were set at 30 months for the Naphtha, Prime D and CFHT Units. The product naphtha is routed to a CCR or Isomerization Unit, diesel to the ULSD pool and VGO to the FCC/post-treater for meeting Tier 3 gasoline.

Liquid Yield

In residue hydrocracking, many of the coke precursors are hydrogenated which results in higher liquid yield and reduced coke production. In addition, the consumption of hydrogen in the liquid product increases the API gravity which in turn leads to greater volume swell and increased production of transportation fuels.

As expected, the overall liquid yield is a function of the residue conversion level and the amount of hydrogen consumed in the liquid product as shown in Table 4. Case 2 shows a 6.0 vol. % increase in liquid yield from Case 1 which equates to 4.2 million barrels per year of additional product (LPG, Naphtha, Diesel and VGO). By increasing the H-Oil®$_{RC}$ conversion from 60 to 70 vol. %, the overall yield increases by 6.6 vol. % over Case 1 which adds an additional production of 4.6 million bbl per year of liquid product. The additional production translates into additional net revenue (product revenue less feedstock cost and operating cost) as shown in Figure 4. The Case 1 expansion adds an additional \$77 million per year while Cases 2 and 2A add more than \$500 million net revenue per year. In contrast with the higher liquid yield, the coke production is reduced by more than 50%. Coke produced in Cases 1 and 2 are 3,114 MTPD and 1,431 MTPD respectively indicating that 54 wt % of the coke precursors were converted in the residue hydrocracker. When the H-Oil®$_{RC}$ conversion is raised to 70%, the conversion of coke precursors is increased to 63 wt % reducing the amount of coke even further. It's for this reason that Case 2A can process more feed without major modification to the existing Delayed Coking Unit.

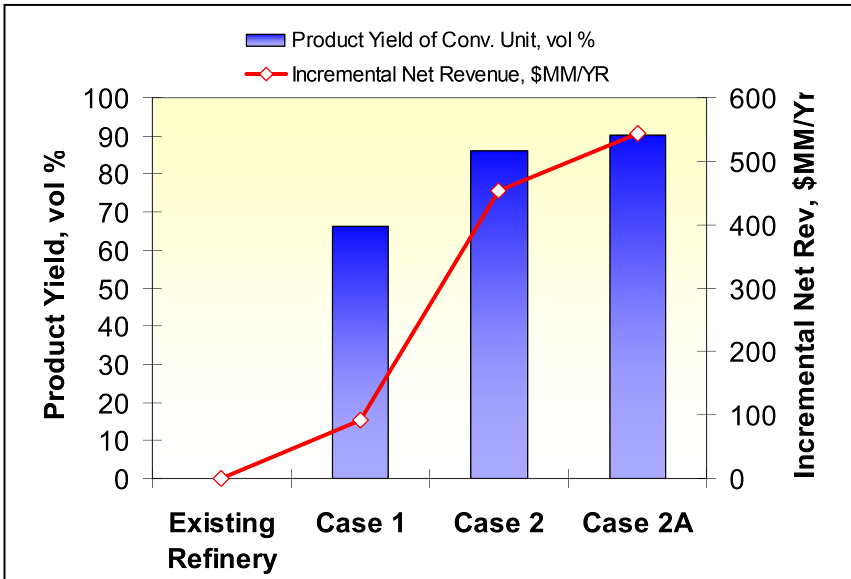


Figure 4 Product Yield of Conversion Unit vs. Incremental Revenue

<u>Selectivity to Diesel Fuel</u>

Ebullated-bed residue hydrocrackers are more selective towards middle distillate production relative to other conversion technologies. With the margin between diesel and gasoline expected to increase in the future, the selectivity becomes more important to the refiner who wants to maximize the economic return of their project. One measure of this selectivity is the ratio of Diesel to Gasoline production. As shown in Figure 5, the selectivity of the conversion unit increases from the Delayed Coking scheme (Case 1) of 1.5 barrels of diesel to 1 barrel of gasoline production to the H-Oil®$_{RC}$/Delayed Coking (Case 2 – at 60% conversion) and reaches the highest value 2.2 barrels of diesel to 1 barrel of gasoline for the H-Oil®$_{RC}$ /Delayed Coking Case 2A – at 70% conversion). For a 200,000 bpsd refinery, the diesel production would increase from 64,400 bpsd (Case 1) to 70,500 (Case 2A) bpsd. The

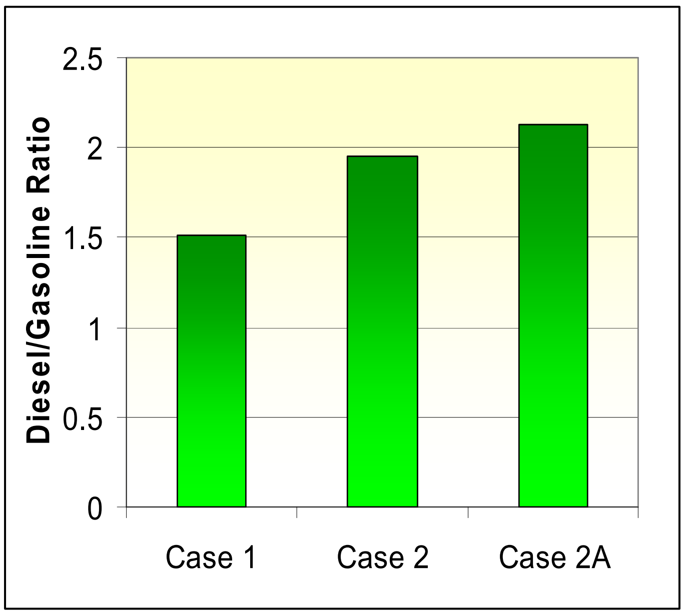


Figure 5 Diesel/Gasoline Selectivity

incremental increase of 6,000 bpsd translates into an additional $234 million of revenue per year for the refinery.

Hydrogen Consumption and Volume Swell

As shown in Table 4, the total hydrogen consumption for the expansion increases by 78% from Case 1 to Case 2A. This in turn results in an overall volume swell increase of 6.6 vol. % on crude which equates to an additional product of 13,200 bpsd for a 200,000 bpsd refinery. As mentioned previously, the base price of industrial natural gas used for this study is $5.00 per thousand standard cubic feet which equates to $30/bbl (foe basis). With gasoline and diesel selling for $109 and $114 per barrel, the consumption of hydrogen provides the refinery with an impressive uplift of $79 to gasoline (i.e. $30/bbl H_2 foe to $109/bbl for gasoline) and $84/bbl uplift for diesel production.

Alternate Case when Processing Athabasca Bitumen

The major results of this case are shown in Table 4. Processing an Athabasca Bitumen or other heavy Canadian crudes will provide economic advantages which includes upgrading a cheaper feedstock with low cost hydrogen to high ºAPI transportation fuels.

Relative to Case 2A, Case 3 provides the highest overall liquid yield on crude of 101.5 % of total liquid product versus 96.9 % for Case 2A. This is due to the lower API gravity of the crude and upgrading to about the same API gravity of the products. This case also represents the highest production of diesel and VGO per barrel of crude for any of the cases examined.

For all of the cases, diesel production could increase further by adding a VGO hydrocracker during the expansion as compared to adding additional CFHT capacity upstream of the FCC Unit. This would also improve the overall refinery Diesel/Gasoline ratio.

ECONOMIC ANALYSIS

For the economic analysis, Axens used the basis presented in Table 2. The investment costs for the expansion cases were only for new units and associated offsites & utilities whereas the revenues and operating expenses were for the entire refinery.

Investment Cost

Axens used its internal database for generating the investment costs for all of the hydroprocessing units as well as published data for the investment of the remaining sections of the plant. Offsites and Utilities were taken as a percentage of the total installed cost for the process units. Figure 6 shows the investment cost breakdown for each of the cases. The investment cost per barrel of crude for the new units varied from \$14,800/bpsd to \$22,400/bpsd with the Delayed Coker expansion at the lowest overall investment. For the expansion cases, the investment cost included a new crude and vacuum unit, Conversion Unit (Delayed Coker or H-Oil®$_{RC}$ Unit), Naphtha, Diesel and VGO hydrotreaters, SMR hydrogen plant, sulfur plant, gas recovery section, amine regeneration, sour water stripping and corresponding offsites plus utilities.

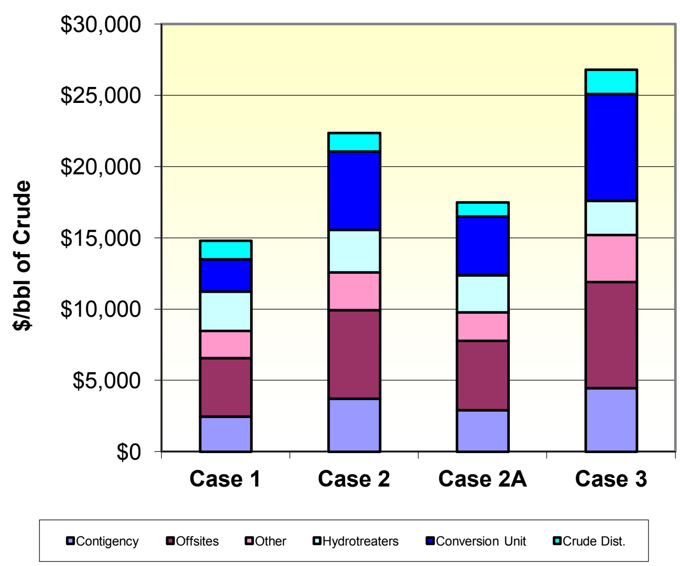


Figure 6 Investment Cost by Case

Operating Cost for ISBL

The total operating cost included fixed and variable operating costs which varied from \$3.15/bbl of crude in Case 1 to \$4.42/bbl for Case 2. Case 3 processing Athabasca Bitumen was the highest with a cost of \$7.98/bbl. The top two operating costs for the H-Oil®$_{RC}$ /Delayed Coker cases (Cases 2, 2A and 3) were natural gas plus catalyst & chemicals versus natural gas and electricity for the Delayed Coker case (Case 1).

Rate of Return

The total net annual revenues (product revenue less crude cost and total operating cost) varied from $169 million for the Delayed Coker expansion Case 1 to $932 million for the H-Oil®$_{RC}$ /Delayed Coker expansion Case 2A based on an Arabian Heavy crude price of $92.48/bbl. The product prices were $109/bbl for gasoline and $114 for diesel.

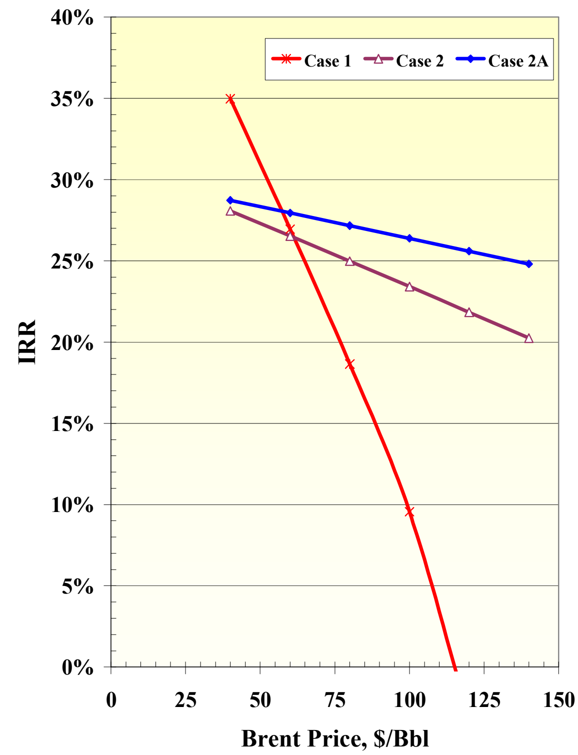


Figure 7 IRR versus Brent Price

As shown in Figure 7, the addition of a residue hydrocracker ahead of a Delayed Coker is more profitable when Brent crude price exceeds $55/bbl. As light oil prices continue to climb, the internal rate of return (IRR) for the Delayed Coker expansion case falls to zero when Brent crude reaches $115/bbl. This is due to the low conversion (i.e. low product liquid yield) and high crude cost. This analysis assumes a constant $/bbl discount to Arab Heavy crude and a constant $/bbl differential between the price of gasoline and diesel to the price of Brent crude. History tells us that variations will occur in both the light – heavy crude price differential as well as price fluctuations in the finished product prices of gasoline and diesel. For this reason, Axens performed a number of sensitivity studies.

Sensitivity Studies

During a sensitivity study, Axens asked the question, "What happens if the diesel to gasoline spread continues to widen?" In all cases the IRR climbs sharply by 6 to 7 percentage points for every $5/bbl the margin of diesel-gasoline increases. In the US Energy Information website forecast, the margins are expected to keep climbing for the short term.

If we ask the question, "What's the impact in processing Athabasca Bitumen from Canada relative to Arabian Heavy?" The IRR doubles from 24% in Case 2 to over 50% in Case 3. This is mainly due to the attractive price of Canadian Bitumen ($68.85/bbl) versus the price for Arabian Heavy ($92.48). The differential of $23.63/bbl for feedstock cost provides a significant incentive for all cases processing Athabasca Bitumen.

During a review of product prices in the US market, Axens noticed higher margins for diesel fuel in the PADD 2 (Midwest market) of \$2 to \$3/bbl. Axens looked at price variations in the diesel – gasoline spread and noticed spreads between -\$5/bbl to + \$17/bbl with a general increasing trend over the last 5 years. As shown in Figure 8, an increase in the price of ULSD fuel versus gasoline provides a tremendous uplift in the IRR for the project.

A project located in the Midwest would see the IRR increased by 4 to 6 percentage points depending upon which expansion case is selected. The same general trend is evident when the gasoline to Brent crude price is increased.

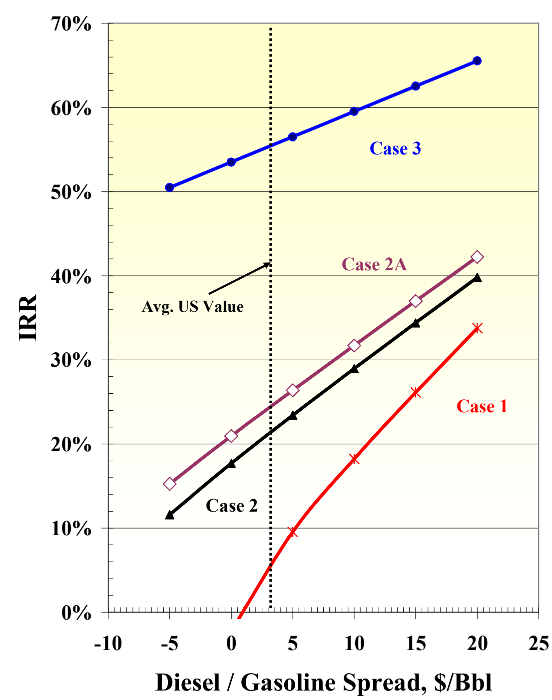


Figure 8 IRR versus Diesel to Gasoline Spread

H-OIL PROCESS RELIABILITY

Residue hydrocracking based on ebullated-bed technology is a mature technology with 17 operating plants processing more than 650,000 bpsd of vacuum residue in North America, Europe, Middle East and Far East. The reliability of the H-Oil®$_{RC}$ Technology has improved over the last 44 years since the start-up of the first plant for KNPC's Shuaiba Refinery in Kuwait. Over the past 10-years of operation the average availability of 6 commercial H-Oil® Plants is 96 % (Figure 9). This high level of reliability is the direct result of nearly 200-unit years of operating experience, automation of operations, pro-active reliability teams, improvements in the understanding of the chemistry of asphaltene conversion and stability through R&D, and on-going improvements in critical equipment, components and process instrumentation.

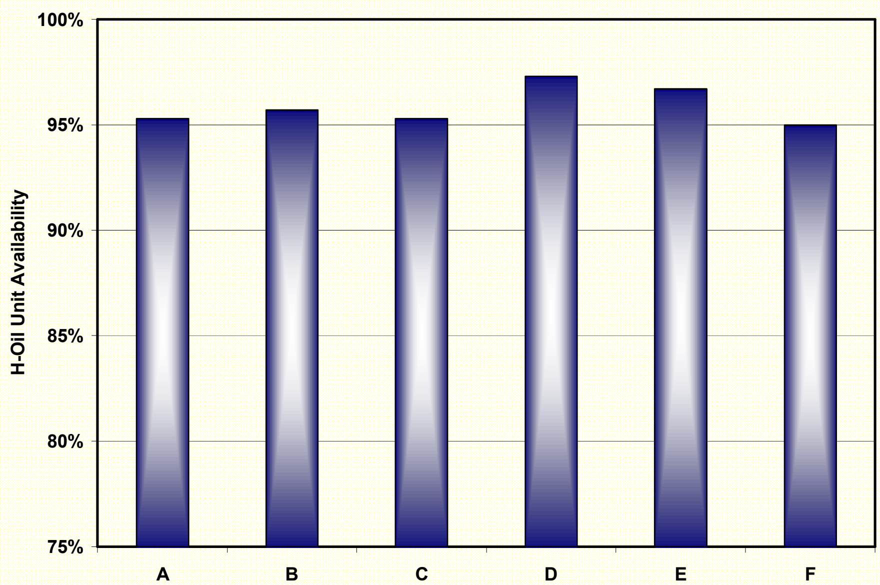


Figure 9 On-Stream Times of Commercial Plants

The plot shown in Figure 9 reflects Unit Availability for 6 H-Oil® Commercial Operating Plants. Unit Availability is defined as the actual on-stream time less planned turnarounds (typically occurs once every 3 to 6 years) and outages due to external factors (i.e. hurricane on the Gulf Coast).

CONCLUSIONS

In the current market of high crude oil prices and low hydrogen costs, hydrocracking of residues is showing good economic rates of returns. When Brent or WTI crude prices exceed $50/bbl or more, the return on investment will favor the addition of a residue hydrocracker ahead of an existing Delayed Coker. This is due to the increase in product yields and more importantly due to the increase in selectivity towards diesel yield. The added revenue under the current economic climate is more than enough to pay for the higher capital investment and operating cost for this type of technology.

Residue hydrocracking based on ebullated-bed technology is now considered a mature technology with 17 operating plants processing more than 650,000 bpsd in North America, Europe, Middle East and Far East.

Acknowledgement

Jim Colyar, a senior technology consultant performed the revised internal study for which this paper is based on. The authors wish to acknowledge his work and contribution to heavy oil upgrading.

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