Life Cycle Assessment Comparison of North American and Imported Crudes

Prepared For

Alberta Energy Research Institute

July 2009

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File No: AERI 1747

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July 2009

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Appendix F **Crude Refining**

Appendix G **Life Cycle Assessment**

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Appendix I **Stakeholder Input**

Executive Summary

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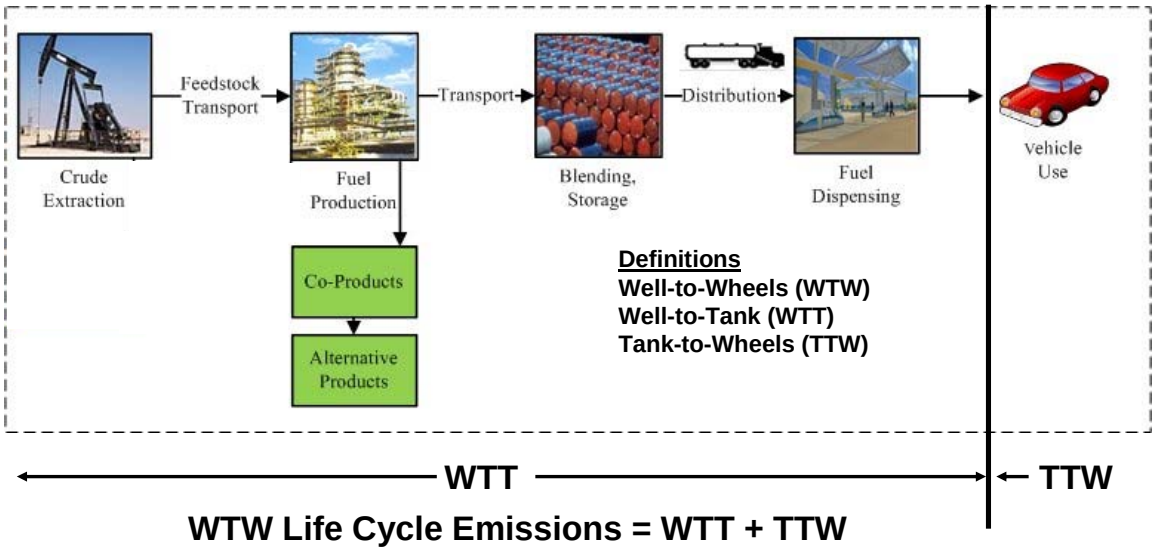
Executive Summary

The State of California has introduced a Low Carbon Fuel Standard (LCFS) with the stated objective of reducing the carbon intensity of its transportation fuels by 10% by 2020. The introduction of a national LCFS in the United States may have implications regarding how the Canadian oil sector responds to the challenge of producing heavy oil and bitumen in an environmentally responsible way. The LCFS standard creates the potential to significantly burden the production of heavy oil and bitumen in Canada, while encouraging production in other parts of the world that have less stringent environmental regulations.

Background

The starting point for determining the carbon intensity of a fuel is a well-to-wheels (WTW) life cycle assessment. This methodology evaluates the energy used and greenhouse gas (GHG) impact in each step from producing a crude oil or bitumen, converting it to transportation fuels, and consuming the fuel in a vehicle. Figure E-1 shows the steps in a WTW lifecycle conversion of crude oils to transportation fuels.

Figure E-1.
Crude Oil Life Cycle Schematic



As shown in Figure E-2, nearly 80% of the GHG emissions come from consumption of the fuel in the vehicle. Only 20% of the emissions result from crude production, refining, transportation and distribution. These results are from an assessment of ULSD production from conventional crude.

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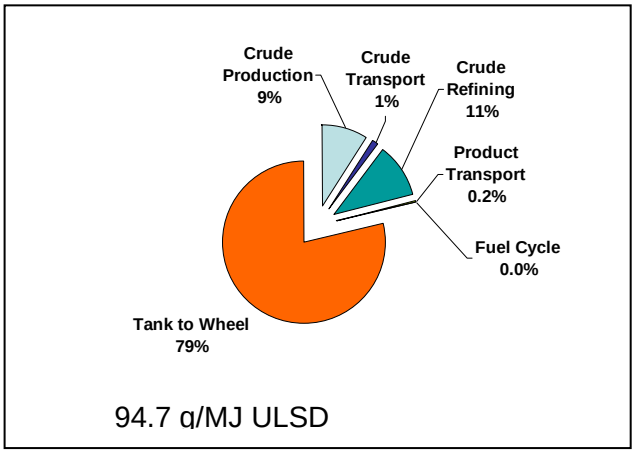
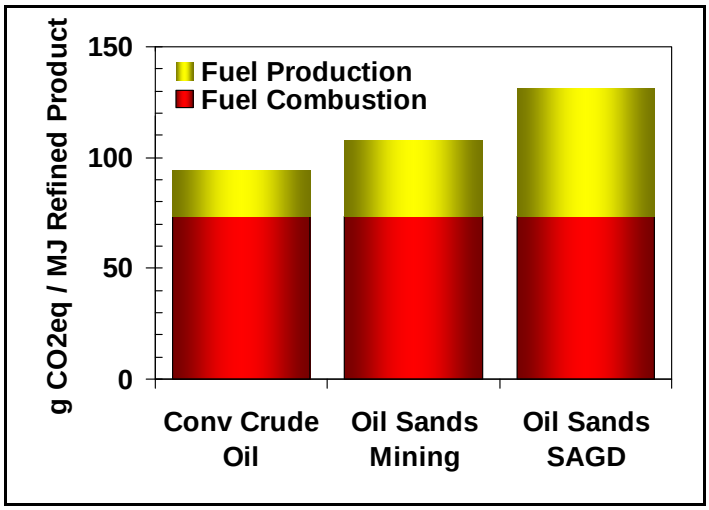
Figure E-2.
CARB Estimate of GHG Emissions from ULSD Production



CARB 2009.

Prior life cycle WTW analyses of GHG emissions from converting conventional crude and oil sands-derived bitumen to transportation fuels have shown that bitumen may have a potential GHG footprint that is much higher than "conventional crude." Results from one such study are shown in the two different bars for oil sands in Figure E-3, representing fuel production from Canadian bitumen via mining and steam assisted gravity drainage (SAGD).

Figure E-3.
GHG Emissions from Transport Fuels Produced from Crude Oil and Oil Sands



Farrell and Sperling 2007

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The results of this previous study, as depicted above, indicate that oil sands may have a potential GHG footprint for SAGD produced bitumen that is as much as 41% higher than conventional crude. However, it is not clear if the above comparison adequately accounts for the large variation in GHG emissions from crude production in different regions that supply crude oil to the US. In addition, previous work has not always accounted for differences in GHG emissions from converting different crudes and bitumens to transportation fuels. Furthermore, earlier efforts do not always address the GHG emissions from the co-products produced while making these transportation fuels.

For example, the extent of flaring during hydrocarbon production can result in a significant source of GHG emissions from conventional crude. Nigeria and Iraq are among the top sources of imported crude to the US and initial estimates indicate that current gas flaring in Nigeria equates to burning as much as 12-18% of the produced crude on an energy-equivalent basis. Gas flaring in Iraq appears to be equivalent to around 7% of the produced crude on this same basis.

Another factor not accounted for in prior lifecycle work is the amount of water produced in conjunction with crude oil. On average, in the US, there are 10 barrels of water produced for every barrel of oil. In Canada, the water to oil ratio is closer to 11. Deepwater oil production from the Mars field in the US Gulf of Mexico is reported to be at a water to oil production ratio over 5. For most reservoirs, water production increases as the reservoir ages. High water production increases the energy needed to lift the oil-water-gas mixture from the reservoir and to treat the mixture as well as clean up the water before either reinjecting it or disposing it.

Other reservoirs that supply significant quantities of oil to the US use somewhat unconventional production methods. Nitrogen injection from the world's biggest air separation plant is being used to increase oil production from the Cantarell field, which supplies Maya crude from Mexico. Heavy crudes from the Lake Maracaibo region of Venezuela are being produced with moderate amounts of steam injection.

Given the above background, Jacobs Consultancy Inc. ("Jacobs Consultancy") was retained by the Alberta Energy Research Institute to provide a fair and balanced Life Cycle Assessment (LCA) of the production of refined products such as gasoline, diesel and LPG from conventional crude oils, bitumen, and synthetic crude oils processed in the United States.

This Life Cycle well-to-wheels Study compares WTW GHG emissions from producing transportation fuels from a representative basket of crudes and bitumens that supply US refineries.

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Life Cycle Analysis Methodology

This study calculates life cycle GHG emissions of petroleum fuels with additional detail to accurately distinguish the effects of different petroleum types, extraction technologies, reservoir locations and transport mode, and processing options. The overall calculation approach is the same as that applied for other fuel life cycle analysis studies (Wang 2008b, Edwards, ARB 2009a). Emissions are summed over all of the steps from crude oil extraction to vehicle end use including the impact of co-products.

The Study generally follows the steps outlined by ISO requirements for Environmental management in 14040 Life Cycle Assessment—Principles and framework and ISO 14044—Life cycle assessment—Requirements and Guidelines. The project team followed these steps by identifying analysis requirements at the planning stage of the project; reviewing the project plan with a stakeholder advisory team; following the progression of activities from developing the scenarios, analyzing the life cycle inventory for components in the fuel cycle, to performing an overall life cycle assessment.

The Study used the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) WTW lifecycle model developed by Argonne National Laboratory. This model is publicly available, supported by Argonne National Laboratory and has been used extensively in previous US evaluations, including the development of the CARB LCFS. The GREET model includes a variety of petroleum and non-petroleum pathways. The configuration of the model treats pathways on a consistent basis with a calculation of average energy inputs and emissions.

However, because GREET uses average energy consumption and efficiencies in processing bitumen-derived products and conventional crude oils, it does not differentiate between specific crude oils and bitumens produced and processed with widely differing amounts of energy and GHG impact. This Study supplements GREET by analyzing the energy and GHG emissions for specific crudes and bitumens in a detailed WTW life cycle analysis.

Note Regarding Methodology: This Study primarily considered WTW direct emissions. The emissions that may arise from land use, resource exploration, the building of infrastructure and facilities, manufacturing and disposal of heavy equipment, etc. is beyond the scope of this work. The treatment of co-products such as petroleum coke and cogenerated electricity is complex, and this Study treated such emissions in a preliminary manner to indicate the need for more rigorous and comprehensive analysis in future work.

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Crudes and Bitumens in Study

The following crudes and oil sands bitumens were examined:

- Arab Medium—Saudi Arabia - a nominal 31.2 API, 2.5 wt% sulfur crude
- Kirkuk—Iraq - 36.6 API, 1.94 wt% sulfur crude
- Bonny Light—Nigeria - 32.9 API, 0.16 wt% sulfur crude
- Maya—Mexico - 22.1 API, 3.3 wt% sulfur crude
- Bachaquero—Venezuela - For our work, we selected the heaviest of the Bachaquero blends at 10.7 API and 2.8 wt% sulfur
- Mars—US Gulf Coast - US domestic sour crude produced in deepwater offshore in the Gulf of Mexico. The crude is 31.5 API, 1.8 wt% sulfur
- Kern River / SJV—California - Kern River is a 13.4 API, 1 wt% sulfur crude produced in the eastern San Joaquin Valley of California using cyclic steam injection
- Oil Sands Bitumen—Canada—both mined and thermally produced by SAGD. In one scheme diluent is refined to gasoline and in a second scheme, diluent is returned to Alberta, Canada. Bitumen in this study has 8.4 API and 4.8 wt% sulfur
- Synthetic Crude Oil (SCO) from a delayed coking-based upgrader in Alberta, Canada
- SCO from an ebulating bed resid hydrocracking-based upgrader in Alberta, Canada

Processing Paths to Refined Products

The processing paths used in the Study for bitumen and conventional crudes are shown in Figure E-4:

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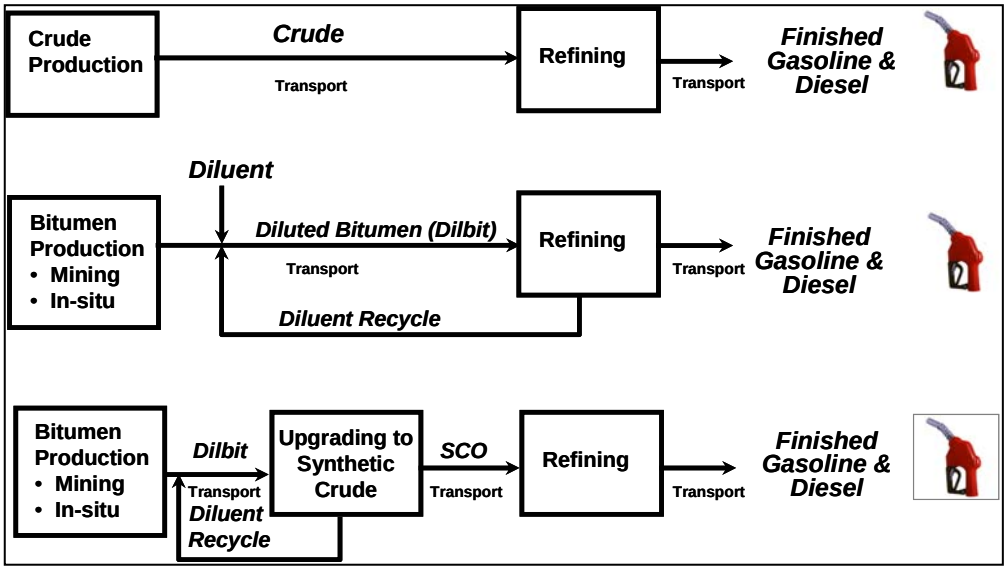
Figure E-4.
Crude and Bitumen WTT Paths



Properly understanding any differences between crudes and bitumens requires understanding the GHG emissions from producing each crude and bitumen and the GHG emissions from converting each crude and bitumen to transportation fuels.

Crude Production

To address the GHG emissions from crude oil production, a crude production model was developed for this Study that estimates energy and GHG impact using the crude oil reservoir and production characteristics together with fundamental engineering unit operations in crude production. Reservoir depth, water to oil ratio, and venting and flaring of produced gas are major factors affecting emissions. Some key aspects of the crudes evaluated are indicated below:

- Nigerian crudes like Bonny Light are produced with some of the world's highest levels of flaring, corresponding in some studies to almost 18% of the energy content of the crude oil.
- Crudes from deepwater Gulf of Mexico are produced from depths over 15,000 ft with moderate water to oil ratio.
- Mexican Mayan crude is produced with the aid of nitrogen injection from the world's largest air separation plant.

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- Bitumens produced in Canada and heavy crudes from California are produced with steam injection—SAGD in Canada and cyclic steam injection in California.
- Crude oils from Saudi Arabia are produced with relatively low energy input and therefore rank among crudes with the lowest GHG impact.

A comparison of reservoir and production characteristics for crudes in this Study is shown in Table E-1.

Table E-1.
Summary of Reservoir and Production Parameters for Study Crudes

Petroleum Reservoir	Avg Depth	Pressure	Thermal Steam to Oil	Water to Oil	Produced Gas	Flared Gas (Wrld Bnk Rpt)	N2 Injection
	ft	psi	bbl /bbl	bbl /bbl	scf / bbl	scf / bbl	scf / bbl
Bachaquero	5,100	500	0.5	0.25	90	70-80	-
Maya	9,500	1,600	-	3	340	20-50	1,200
Arab Medium	6,100	3,000	-	2.3	650	25-30	-
Mars	14,500	5,500	-	5.5	1,040	20-25	-
Bonny Light	8,700	4,300	-	2	840	650-840	-
Kirkuk	7,500	3,000	-	2	600	300-400	-
California Heavy			~5	-			
Bitumen - SAGD			~3	-			
Bitumen – Mining							

The GHG impact for producing the different crudes and bitumens in the Study is summarized in Figure E-5. Although Figure E-5 shows a range in steam to oil ratio from less than 3 to over 5 bbls of steam (reported as water) to each bbl of oil produced by SAGD, the average steam to oil ratio in Canada is around 3. California steam injection is cyclic; an SOR of 5 in California translates to approximately 4 SOR on a Canadian SAGD basis. Bitumen mining in Canada is less energy-intensive than SAGD.

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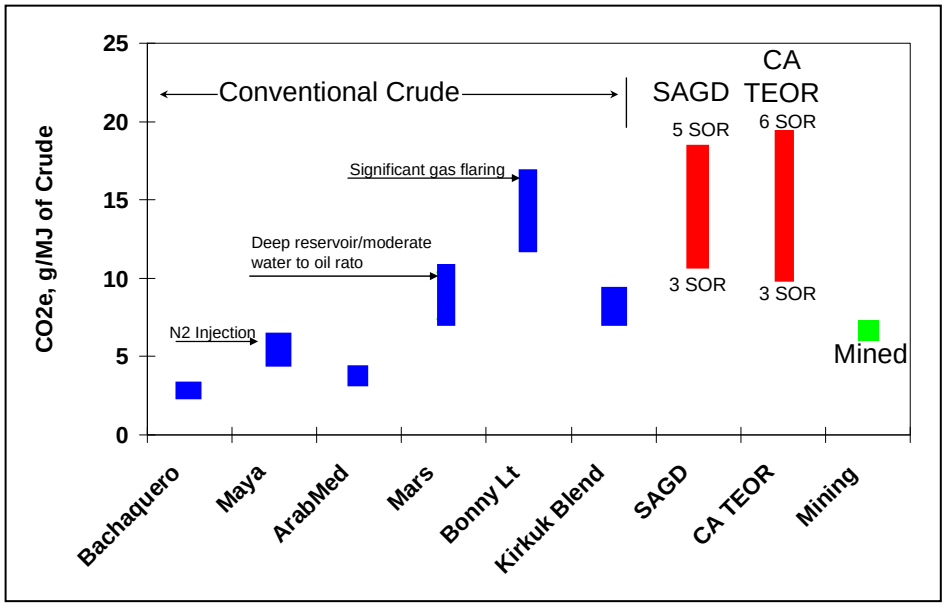
Figure E-5.
GHG Emissions from Crude Production—Conventional and Unconventional Production



Legend:

- Conventional crudes—crude production by conventional means
- SAGD—bitumen production by steam injection using the SAGD process
- CA TEOR—California thermal enhanced oil recovery using cyclic steam injection in the central valley of California (Kern River)
- Mined—bitumen produced by surface mining. Bitumen must be separated from clay and sand

GHG estimates for crude and bitumen production show an overlap of GHG emissions—especially with crudes from deep reservoirs and where a significant volume of associated gas is vented and flared.

Refining and Upgrading

To address differences in refining intensity for converting different crudes, bitumens and SCOs to transportation fuels, non-linear upgrading and refining models were used in this Study. The models were tuned to take into account the different properties of the crudes, SCOs, and bitumens. The refinery configuration is representative of a high conversion modern refinery located in PADD 2 of the US, which uses a coker, FCC and other processing units to maximize gasoline and diesel production. In this study, SCO was assumed to be produced in Alberta in either a delayed coking-based or an ebulating-bed resid hydrocracker-based upgrader.

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Co-products produced in upgrading are sulfur, light ends and coke from the delayed coking unit. Coke produced in upgrading is assumed to be stored and not used elsewhere. The GHG burdens for producing coke, light ends, and sulfur in the upgrader are distributed to SCO.

Co-products produced in refining are LPG, coke, and sulfur. The GHG burdens from producing LPG, coke and sulfur are distributed to gasoline and diesel. In addition, because coke from refining is assumed to be used as a substitute for coal in electric power generation, the additional burden from transporting and burning coke instead of coal is distributed to gasoline and diesel. There are very few differences between LPG from refineries and other sources.

Crude Transport and Product Distribution

Our calculation of emissions from transportation of crudes, bitumen, and SCO to the upgrader and refinery as well as distribution of products from the refinery uses factors from the GREET model. Transport distances reflect the location of the oil reservoir considered in this Study. Fuel cycle emissions for producing the natural gas and electricity used to produce and convert the crude and bitumen to transportation fuels also use factors from GREET.

Life Cycle WTW Results

Life cycle well-to-wheels results from the Study are summarized in Figure E-6 for RBOB (reformulated blendstock for gasoline blending), which is a low vapor pressure gasoline blend ready for addition of up to 10 vol-% ethanol. The results show that the GHG emissions from producing transportation fuels from oil sands bitumen are smaller than suggested by previous studies. Results for RBOB are similar to those for CBOB (conventional blendstock for gasoline blending), a higher vapor pressure blend than RBOB, and ULSD (ultra-low sulfur diesel). The band in Figure E-6 represents the 6% GHG emissions gap between two conventional crudes, Arab-Medium and Mars. The GHG gap between Mars and Bonny Light is around 8%.

Our results show that the WTW GHG difference between Arab-Medium and bitumen is less than 18% for bitumen from SAGD and approximately 10% for bitumen from mining. Both of these bitumen cases assume that the bitumen is first upgraded to SCO in a delayed coking-based upgrader before refining the SCO in a PADD2 refinery. If instead diluted bitumen is shipped to the PADD2 refinery, the difference between Arab-Medium and bitumen drops to 15% for bitumen produced by SAGD. If the diluent is then converted to gasoline in the refinery, total WTW GHG emissions are comparable to the conventional crudes. The gap between Bonny-Light and diluted bitumen sent to a PADD2 refinery is only 6% (assuming diluent return to Alberta).

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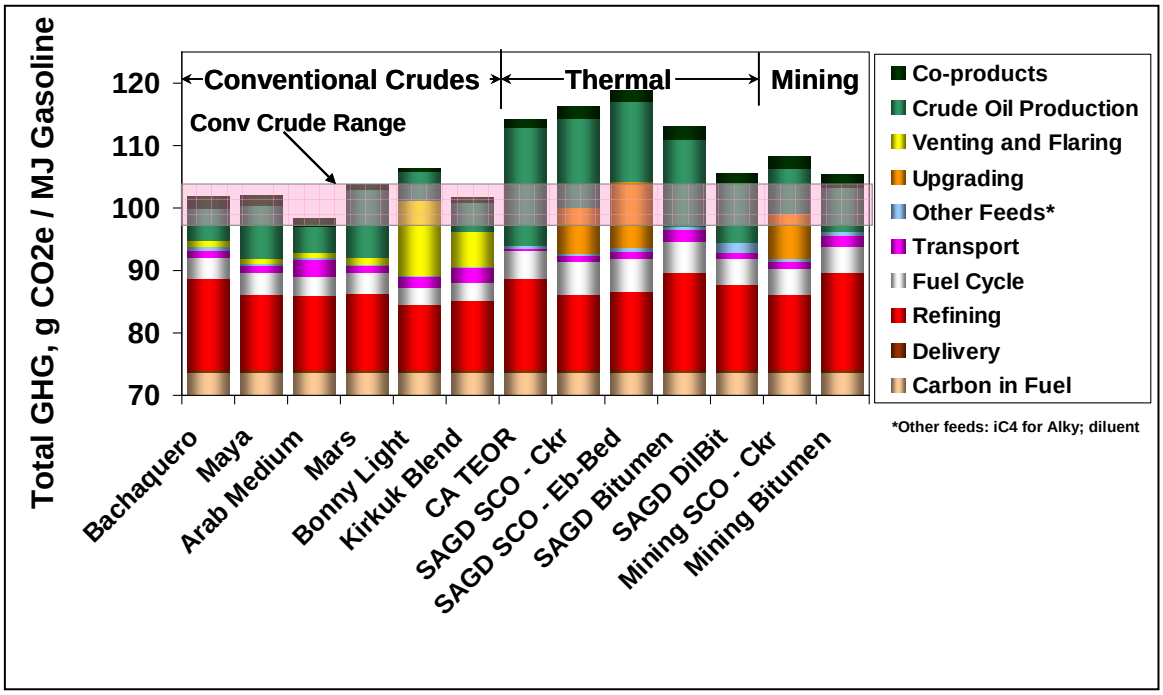
Figure E-6.
Life Cycle Assessment of WTW GHG Emissions for Crude and Bitumen to RBOB



Note: Life cycle emissions, represented herein as WTW, include WTT emissions plus fuel carbon as CO_2, plus vehicle methane and N_2O. For identical vehicles, the gCO_2e/MJ representation above is the same as a traditional WTW representation in $gCO_2e/mile$.

Legend:

- Conventional crudes: Bachaquero; Maya; Arab Medium; Mars; Bonny Light; Kirkuk crude oils produced and transported to a high conversion refinery in PADD2 of the US where the crude is converted to mainly gasoline and diesel fuel used in PADD2.
- CA TEOR—California thermal enhanced oil recovery using cyclic steam injection in the central valley of California (Kern River). This heavy oil is refined in a high conversion refinery in California. Diesel and gasoline are used in California.
- SAGD SCO—Ckr – Bitumen produced in Alberta with a 3 SOR, upgraded in delayed coking based upgrader to produce bottomless SCO that is sent to a high conversion refinery in PADD 2 to produce primarily gasoline and diesel fuel.
- SAGD SCO—Eb-Bed – Similar to the prior case except that the SCO is produced in an upgrader based on an Ebulating Bed resid hydrocracking unit. The SCO contains unconverted oil.
- SAGD Bitumen—Bitumen produced in Alberta using a 3 SOR is transported to a US PADD 2 refinery as dilbit (naphtha diluent and bitumen); naphtha diluent is returned to Alberta.

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- SAGD—Dilbit – Similar to the previous case except that the diluent is not returned to Alberta and is instead converted to gasoline.
- Mining SCO—Ckr – Bitumen produced by surface mining is upgraded to SCO in a delayed coking based upgrader, shipped to a PADD2 refinery and converted to primarily gasoline and diesel fuel.
- Mining Bitumen—Bitumen produced in Alberta by surface mining. The bitumen is shipped to a PADD 2 refinery as Dilbit. The diluent is returned. This example is not extensively practiced because of the high sediment, chloride and water content of mined bitumen. However, with technology improvement, this practice may become more prevalent in the future.

Impact of Cogeneration

Onsite natural gas cogeneration is a significant source of steam and electric power for thermal oil production in both Canada and California. The use of cogeneration to produce both power and steam is more efficient than producing each utility separately. The base WTW results presented above in Figure E-6 for thermally produced California crude and Canadian bitumen reflect the efficiency and direct utility emissions from oil production based on a level of steam and power cogeneration to the extent that the production facility power needs are fully met but without any net export of power.

However, many of the production sites in both Canada and California generate a larger amount of steam and power using onsite natural gas cogeneration and export excess electric power to the local grid as a co-product. Thus, from a life cycle perspective, co-product emissions credits may apply if displacing power generated using higher carbon content fuel, such as coal-fired power.

While the scope of this Study did not include a comprehensive evaluation of site-specific cogeneration opportunities and impacts, a preliminary analysis was carried out for Canadian bitumen to illustrate the potential for such co-product emission credits from export of cogenerated power. This preliminary analysis assumes substitution of the natural gas-fired cogenerated export power replacing local grid electricity. This substitution method is consistent with the GREET model's treatment of import and export power and associated indirect emissions. For example, in determining the co-product emissions impact of cogenerated power associated with cellulosic ethanol production in the US, the average US grid mix is assumed to be offset.

For illustrative purposes, the following basis was used for the preliminary analysis of cogeneration power export from Canadian bitumen production sites:

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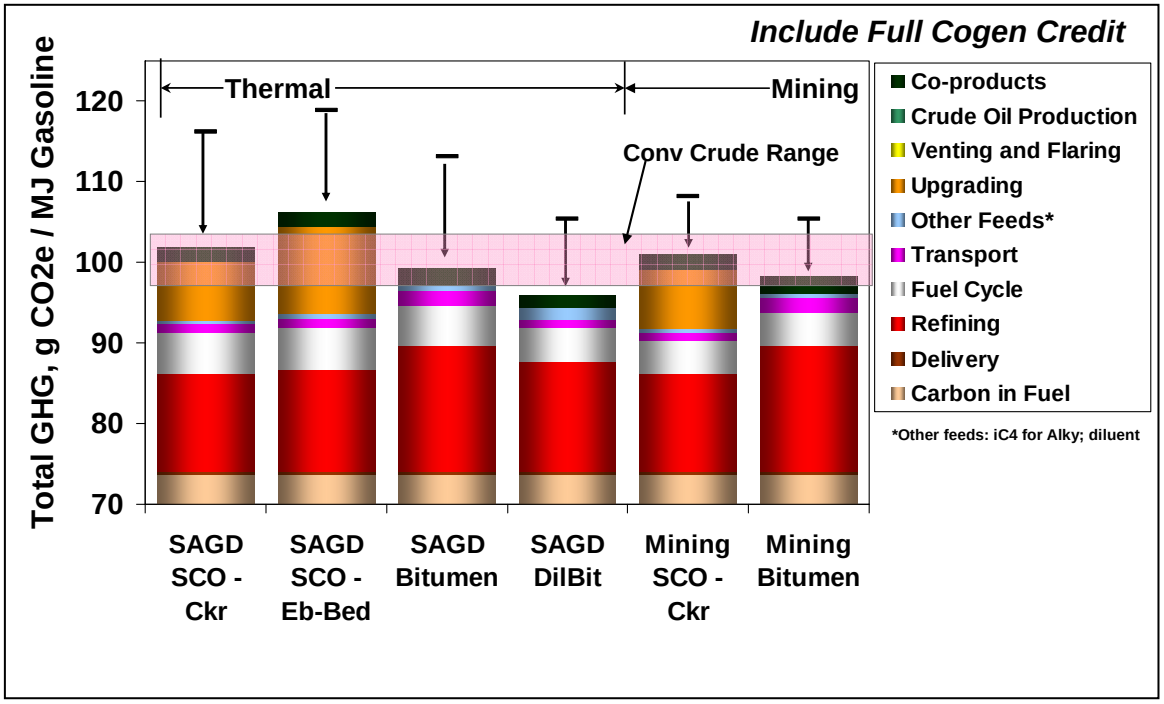
Full Credit Case Basis (Figure E-7)	Natural Gas Fired Cogen Power Export, kwh/bbl	Local Grid Power Displaced
SAGD Bitumen	99	80% coal fired
Mined Bitumen	48	80% coal fired

The level of export power shown above is based on generating 100% of the steam required for bitumen production via cogeneration. While not all bitumen production sites currently in operation export this much power, most new facilities are being designed this way. It should also be noted that a rigorous evaluation of the local power grid was not carried out to determine the actual mix that would be displaced by cogenerated export or the impact on grid efficiency.

Figure E-7 shows the potential impact on WTW life cycle GHG emissions from Canadian oil sands for the basis indicated above. The arrows on the diagram show the change in GHG emissions from applying this full cogen credit. For the set of assumptions used in this preliminary analysis, the export provides enough co-product emissions credit to essentially offset the GHG emissions from bitumen production. When these credits are applied, the result is that the life cycle GHG emissions for bitumen-based fuels are well within the range of fuels from conventional crudes.

Figure E-7.
Life Cycle Assessment of WTW GHG Emissions for Bitumen to RBOB— Full Credit Basis for Cogenerated Power Export



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It should be noted that the above credit may not be fully achievable based on the actual amount of export power from specific production facilities, the actual Alberta grid mix (coal, gas, hydroelectric, other), the balance and source of grid base and peak power production, and the impact of the exported power on the existing power generation facilities supplying the grid. It should also be noted that the analysis of cogeneration and power export is relatively complex. For example, while the availability of this electricity supply may avoid the need to construct some type of new power plant or the need to procure the same amount of electricity from some other source, it may also cause excess capacity on the grid and inefficient operation of other electricity generation resources.

Therefore, a more detailed evaluation is required to more accurately understand the potential credit for cogeneration and power. Regardless, the impact of cogeneration is significant, and even if only one-half of the above credit indicated in Figure E-7 is achievable, the life cycle WTW GHG emissions for fuels from bitumen produced by mining and SAGD are still within the range of many of the conventional crudes examined in this Study as shown in Figure E-8.

Lastly, it should be noted that the above analysis was not carried out for California thermally produced crudes as part of the Study. Potential for export power co-product emissions credits also exist for these California crudes. It is recommended that this potential be considered as part of a future, more comprehensive evaluation regarding the impact of cogenerated power export.

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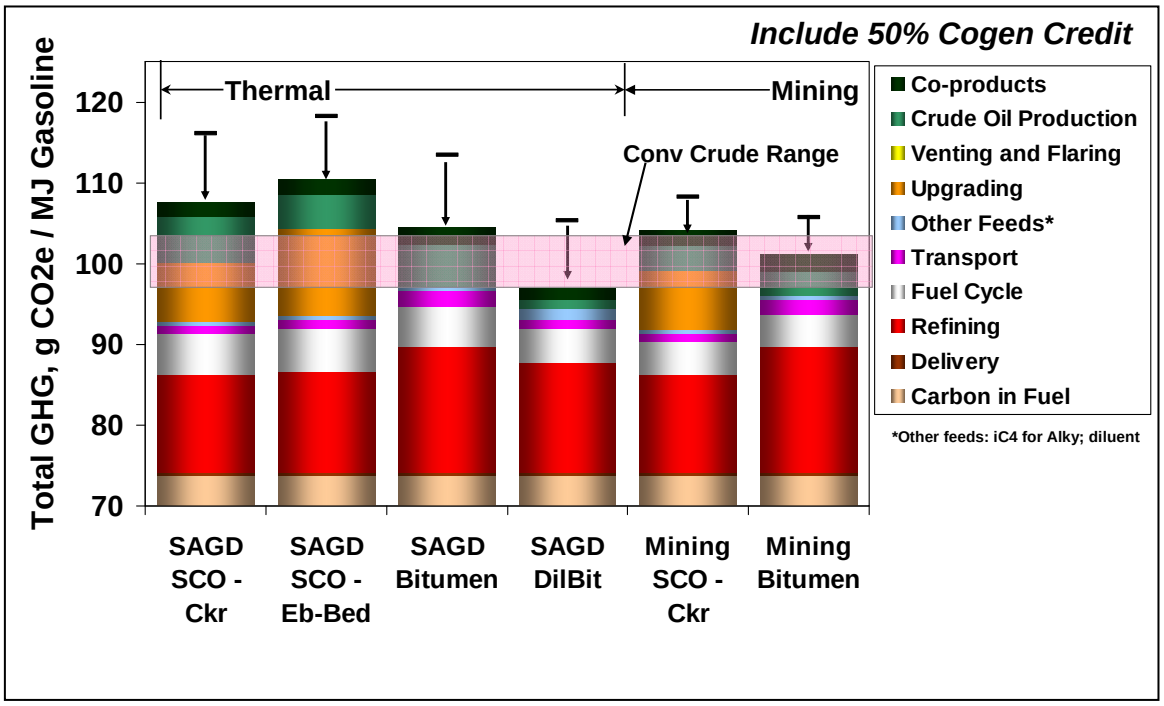
Figure E-8.
Life Cycle Assessment of WTTW GHG Emissions for Bitumen to RBOB – 50% Credit Basis for Cogenerated Power Export



Conclusions

- Accurate ranking of specific crudes and bitumens requires an in-depth Life Cycle Analysis that takes into account the actual differences in energy and GHG impact from their production, upgrading and refining to products.
- Crude production modeling provides transparent and consistent handling of crudes and fills gaps in inaccurate or incomplete public data. Much of the information that is publicly available about crude production is either too aggregated or missing important pieces of information, thereby making WTW analysis of crudes and bitumens unreliable. Use of a fundamental crude production model supplemented with actual data provides a better understanding of the major factors affecting GHG emissions from crude production.
- Rigorous upgrading and refining models define emissions for specific crudes and allow differentiation of GHG burden between products. Heavier crudes require more energy to refine and therefore have greater GHG impact. Products that require significant refining tend to have greater GHG impact than products with less refining. Accounting for the impact of crude and processing will result in better understanding of WTW GHG impact for different fuels produced from different crudes and bitumens.

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- GHG emission gaps between bitumen and conventional crudes are smaller than reported in some prior studies. The wide range of GHG impact from conventional crudes as a result of energy intensive production methods is one of the significant outcomes of this study and will enable more informed discussion of LCFS policy.
- Unique opportunities exist to improve the GHG footprint for Canadian oil sands relative to other crudes. These include cogeneration as well as large scale efficiency improvement and carbon capture and storage opportunities.
- New facilities built in Canada for bitumen production, upgrading, and refining can more easily and cost effectively manage GHG emissions than older facilities in the US or offshore oil production sites with less rigorous environmental standards. In addition, many new facilities in Canada are near sites that can be used for CO_2 sequestration.

Recommendations

Recommendations for areas of further work identified as part of this Study include:

- Widen the scope of crudes analyzed to include crudes such as Alaskan North Slope, which is refined in California, additional US domestic crudes, and Canadian crudes
- Evaluate other bitumen upgrading technologies and configurations, including those that directly utilize coke or a portion of the bitumen for upgrading energy supply.
- Identify and determine the magnitude of potential energy and efficiency improvements in the full WTW lifecycle of producing, upgrading, and refining bitumen.
- Develop a more thorough analysis of cogeneration credit opportunities for thermally produced heavy crude and bitumen in California and Canada.
- Evaluate the impact of large scale carbon capture and sequestration on bitumen production, upgrading and refining in Canada
- Determine the lifecycle impact of using alternative fuels in bitumen production, upgrading and refining
- Consider how the potential mitigation opportunities might also apply to other crudes.

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References

California Air Resources Board, *Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California*, February 28, 2009

Farrell, Alexander E. and Sperling, Daniel, *A Low-Carbon Fuel Standard for California Part 1: Technical Analysis*, UC Berkeley and UC Davis, 2007

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Section 1.

Introduction

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Low Carbon Fuel Standard

The State of California has introduced a Low Carbon Fuel Standard (LCFS) with the stated objective of reducing the carbon intensity of its transportation fuels by 10% by 2020. The LCFS shall apply to all refiners, blenders, producers and importers of transportation fuels and shall be measured on a full fuels cycle basis (Executive Order S-01-07, Office of the Governor of the State of California, January 18, 2007). Other US states, Canada and other countries are also considering implementing similar LCFS regulations.

Currently California imports only small quantities of Canadian oil. However, the United States imports more oil from Canada than anywhere else in the world, with a growing proportion coming from heavy oil, oil sands bitumen and upgraded synthetic crude oil. Therefore, the introduction of a national LCFS in the United States may have implications regarding how the Canadian oil sector responds to the challenge of producing heavy oil and bitumen in an environmentally responsible way.

The LCFS standard creates the potential to significantly burden the production of heavy oil and bitumen in Canada, while encouraging production in other parts of the world that have less stringent environmental regulations. Whereas several Canadian oil companies have carried out life cycle assessment on their operations, there have been few well-to-wheel comparisons of Canadian heavy crude oil and bitumen derived crude oils with US domestic crude oils and other crude oils imported into North America.

For reference, the primary life cycle steps typically considered in a well-to-wheels analysis of crude oil to transportation fuel production are shown in the simplified diagram in Figure 1-1.

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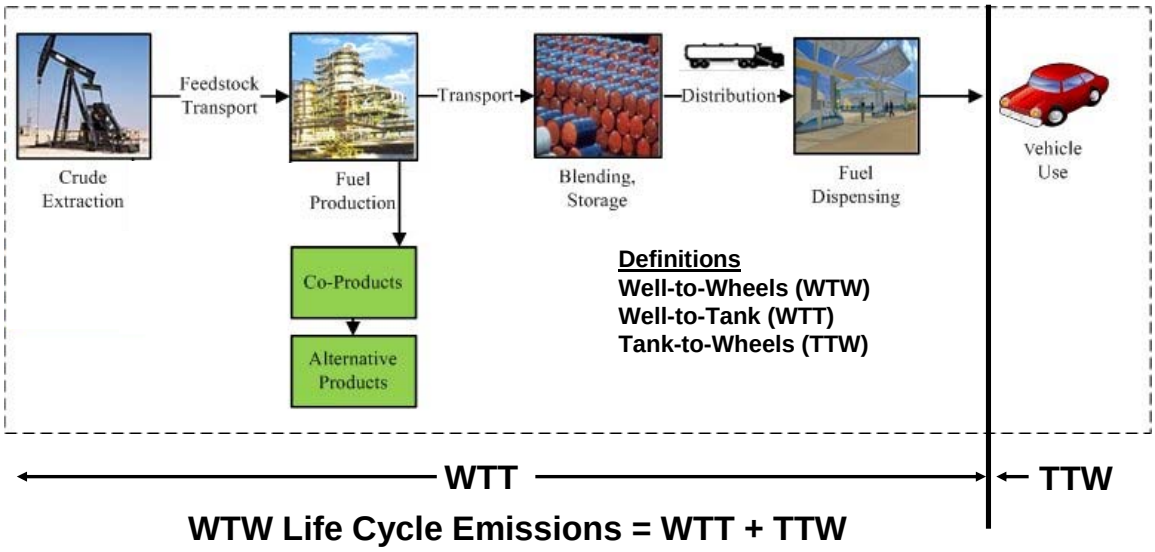
Figure 1-1.
Crude Oil Life Cycle Schematic



The first step in the crude life cycle is resource extraction, which may, for example, be crude production from a well or bitumen production via mining or steam assisted gravity drainage (SAGD). Next is initial processing, which may include separation of light ends from conventional crude or field processing and upgrading of bitumen. The resulting conventional crude oil, synthetic crude oil, or diluted bitumen is next transported to refineries for conversion to transportation fuels, which are then moved to market for consumption in vehicles. A simplified diagram showing the different paths taken by oil and bitumen to the point of putting the fuel into the vehicle (well-to-tank or WTT) is shown in Figure 1-2. Different crude oil sources require different levels of energy to extract and convert them to transportation fuels, and may therefore have very different life cycle greenhouse gas (GHG) impact.

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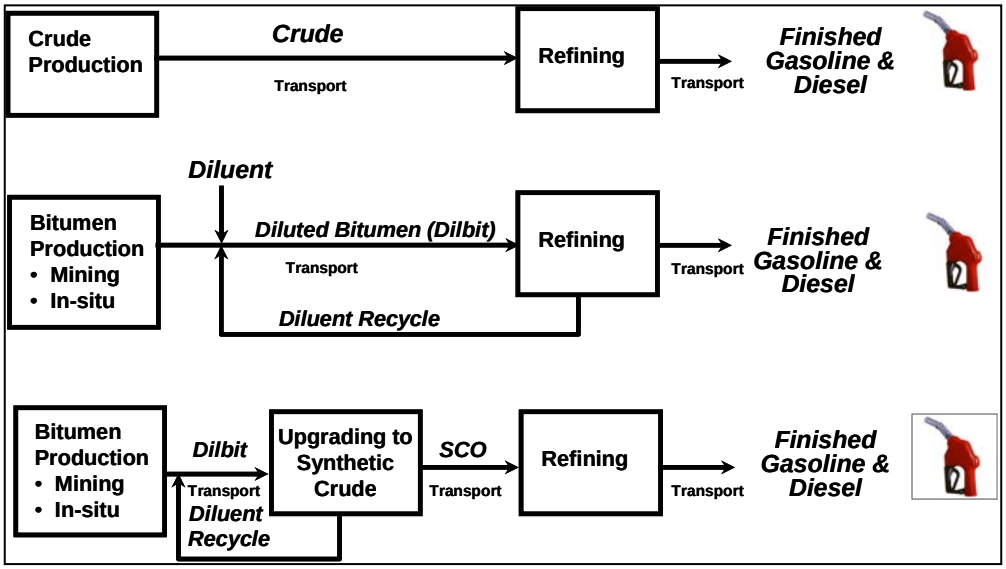
Figure 1-2.
Crude and Bitumen WTT Paths



The key shortcomings of existing life cycle analyses include:

- ***Outdated Information:*** Prior life cycle analyses may lack current data and may use or extrapolate historical public data, which are not representative of current practices.
- ***Regional Differences and Regulatory Environment:*** Most life cycle analyses use generic information. For example, there could be significant differences in the level of greenhouse gas (GHG) emissions associated with the production of a barrel of oil in North America compared to a barrel produced in countries with less stringent environmental regulations, or use older technologies, and then deliver the oil to North America. Regional differences in types of energy used to produce the oil, ranging from natural gas to electricity, are often not accounted for in many prior life cycle analyses.
- ***Emerging Technologies:*** Existing life cycle analyses may not include emerging technologies that will mitigate GHG emissions, from the latest energy efficient process technologies to carbon capture and storage (CCS).
- ***Incomplete Analyses:*** Many life cycle analyses do not include all the stages from well-to-wheels (*e.g.,* the flaring of co-produced natural gas in Africa or the energy required for water desalination for secondary oil recovery in the Middle East). In addition, existing life cycle studies have not adequately dealt with by-products from refining such as petroleum coke, fuel oil, and other non-transportation fuel products.
- ***Excessive Aggregation and Over Simplification:*** Some life cycle models may integrate stages. For example, they may generically combine upgrading and refining. In

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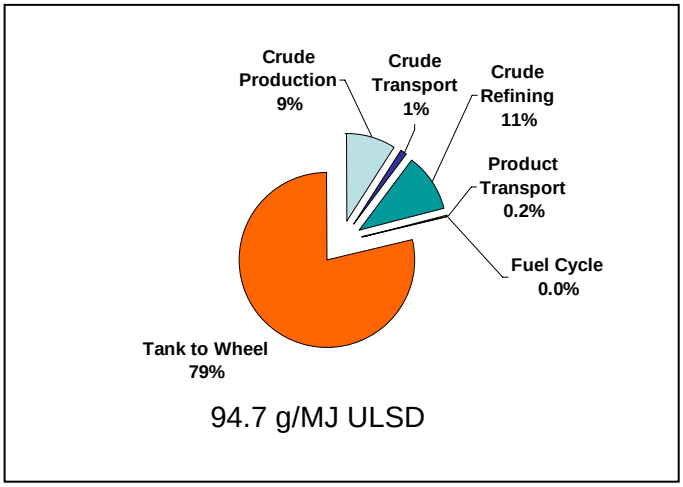
addition, many studies do not properly assign the energy used in production of each transportation fuel. These studies simply assign a portion of the overall energy used in refining to each transportation fuel rather than determine how much energy is used by each refining step to produce a particular transportation fuel. Assigning overall refinery energy consumption to each fuel eliminates the ability to differentiate GHG emission impact from changing the refined product mix. In addition, general production and refining models—which lack the required fidelity to adequately distinguish between varying crude sources and product mixes—are often used.

- ***Differing Boundary Conditions:*** Boundary conditions used in life cycle analyses may vary. For example, some analyses may include the GHG emissions from energy required for the production of cement and steel used in the construction of the production/refining facilities.

Current State of Life Cycle Studies Related to LCFS

A number of life cycle studies have been conducted to evaluate California's new LCFS. Results from a recent study for the production of ULSD in California are shown in Figure 1-3.

Figure 1-3.
CARB Estimate of GHG Emissions from ULSD Production



CARB 2009

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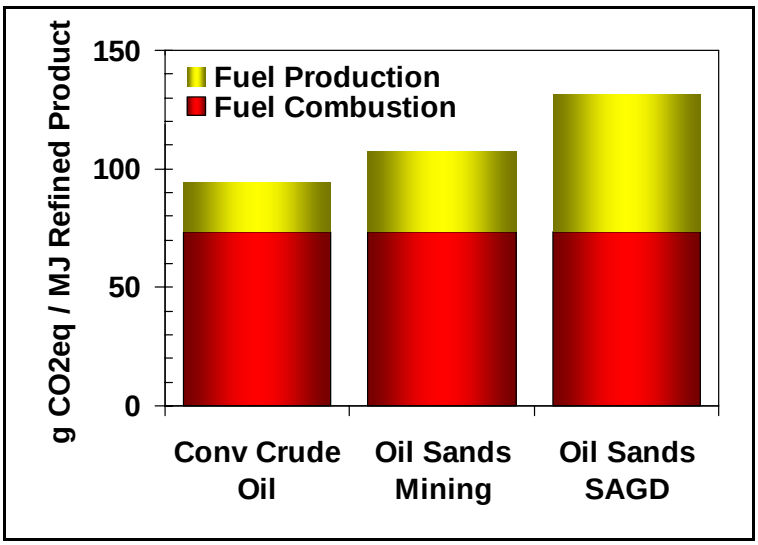
Results for each step in the life cycle are reported in grams of CO_2 equivalent per MJ of transportation fuel produced. The major sources of greenhouse gas emissions are fuel consumption, crude oil refining, and crude oil recovery. Emissions from transportation of crude oils to refineries and emissions from the distribution of fuels to market are typically a much smaller component of the overall GHG emissions in the full life cycle.

In addition to CO_2 emissions from fuel used directly in converting crude or bitumen to transportation fuels, there are also CO_2 emissions from the production of electricity used in these steps. CO_2 emissions from electricity generation depend on the fuel mix used to generate that electricity, which is specific to a region and country.

A key point to note about Figure 1-3 is that the numbers shown are for an average crude and average refinery. They do not show differences that may arise from producing and processing different crudes.

Figure 1-4 is based on data from a previous study analyzing the technical impact of the LCFS in California. It compares potential GHG emissions for the production of transportation fuels from both conventional crude oil and from oil sands. The two different bars for oil sands represent bitumen production by mining and SAGD.

Figure 1-4.
GHG Emissions from Transport Fuels Produced from Crude Oil and Oil Sands



Farrell and Sperling 2007

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The results of this previous study, as depicted above, indicate that oil sands may have a potential GHG footprint that is 14-41% larger than "conventional crude." However, it is not clear if the above comparison adequately accounts for real differences that can be attributed to specific crude oils and actual refining facilities.

For example, the extent of flaring during hydrocarbon production can result in a significant source of GHG emissions from conventional crude. Results in the following table show the top countries that flare gas and their crude production in 2004. Nigeria and Iraq are among the top sources of imported crude to the US and have some of highest ratios of flared gas to produced crude. Initial estimates indicate that current gas flaring in Nigeria equates to burning about 10-15% of the produced crude on an energy-equivalent basis. Saudi Arabia, which has a much better infrastructure for recovery of associated gases from crude oil production, had a ratio of flared gas to crude production of 0.8 m^3/ bbl of crude in 2004, less than 0.5% on an energy-equivalent basis.

Table 1-1.
Top Gas Flaring Countries in 2004

	Gas Flaring	Oil Production	Flaring/ bbl of Crude
	Billion m^3	KBPD	m^3/ bbl
Russia	25.7	9,274	7.6
Nigeria	23.0	2,332	27.0
Iran	11.4	4,104	7.6
Iraq	8.1	2,021	11.0
Kazakhstan	5.8	1,246	12.8
Algeria	5.5	1,967	7.7
Angola	5.2	1,054	13.5
Libya	4.2	1,582	7.3
Qatar	3.2	1,043	8.4
Saudi Arabia	3.0	10,496	0.8
Indonesia	2.9	1,183	6.7
China	2.9	3,657	2.2
Kuwait	2.6	2,515	2.8
Gabon	2.5	239	28.7
Oman	2.5	754	9.1
Uzbekistan	2.1	142	40.5
Venezuela	2.1	2,855	2.0
Egypt	1.7	700	6.7
Malaysia	1.7	862	5.4

World Bank, 2007

EIA

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Regional differences in CO_2 and CH_4 emissions from oil production are shown in Table 1-2. These differences further illustrate the risk of using average GHG emissions for conventional crude oil production.

Table 1-2.
Regional differences in CO_2 and CH_4 Emissions from Oil and Gas Production

	Africa	Asia/ Australasia	Europe	FSU	Middle East	North America	South America	Overall
	T/KT of Oil	T/KT of Oil	T/KT of Oil	T/KT of Oil	T/KT of Oil	T/KT of Oil	T/KT of Oil	T/KT of Oil
CO_2	262	153	70	132	83	150	134	142
CH_4	1.45	1.41	0.25	0.78	0.41	1.45	1.42	1.00

International Association of Oil & Gas Producers, 2007

The previous examples all point out that GHG emissions for the transportation fuel life cycle depend highly on the source of hydrocarbons and the methods used to extract and process the hydrocarbons to transport fuels. Further, energy consumption in refining of crude oils is highly dependent on the type of crude processed and the refined product slate. Refineries that process heavy crude oil mainly to transportation fuels have much greater energy intensity than refineries that process light crude oil to a mix of transportation fuels and heavy fuel oil. Using an average GHG emissions for crude oil production or for refining is an over simplification A better approach is to use the actual GHG emissions emitted for each crude oil or bitumen-based oil in each step of its specific life cycle.

Primary Study Objectives

Given the above background, Jacobs Consultancy Inc. ("Jacobs Consultancy") was retained to provide a fair and balanced Life Cycle Assessment (LCA) of the production of products such as gasoline, diesel and LPG from conventional crude oils, bitumen, and synthetic crude oils processed in the United States.

It is recognized that the production of refined products from bitumen is generally more energy intensive than from processing other crude oils, especially lighter crude oils from West Africa. However, the full cycle of energy use in crude oil production, flaring of associated gases, shipping, as well as the potential for CO_2 capture are generally not recognized and have not been incorporated into prior studies.

Many well established life cycle models used in LCA analysis, such as the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model from Argonne National Laboratory, use average energy consumption and efficiencies in processing

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bitumen-derived products and conventional crude oils instead of using energy consumption and GHG impact that more accurately represent each step in the fuel cycle from production and processing of each crude. In addition, models such as GREET do not incorporate differences in GHG mitigation potential between different crudes.

As a result, prior life cycle assessments have not differentiated the GHG production and mitigation potential for transportation fuels derived from different pathways. This lack of differentiation means that fuels derived from upgrading heavy oils or bitumen may in the future be excluded from markets subject to LCFS, despite the fact that CO_2 emissions may be more easily mitigated from heavy oil and bitumen upgrading to refined products than from processing more conventional crude oils in North American refineries, especially those that are in locations farther from geological formations suitable for carbon capture and storage.

Therefore, the primary objectives of this Study were to:

- Enhance generic well-to-wheel life cycle assessment of transportation fuel production and consumption with an assessment that more properly reflects differences between crude oil production, upgrading, and refining, for a representative basket of benchmark crudes processed in the United States.
- Ensure transparency of results, methodology and underlying data by using public and defendable data sources and recognized and transparent LCA methodology and model—similar to what is used in California for LCFS and other well vetted life cycle studies.

More detail regarding the life cycle study objectives and methodology is provided in Section 2, Life Cycle Analysis Approach.

Life Cycle Assessment Methodology and Modeling

The Study followed recognized ISO-14000 methodology for Life Cycle Assessment.

The Study included analysis of the full well-to-wheels life cycle, as previously depicted in Figure 1-1, encompassing:

- Crude / bitumen production and initial processing
- Crude / bitumen transportation and storage (SCO transport for appropriate cases)

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- Crude / bitumen upgrading and refining
- Motor fuel distribution
- Vehicle operation

Results are reported in grams of CO_2 equivalent per MJ of transport fuel (gasoline, ULSD, *etc*.).

Upgrading and Refinery Modeling

Because upgrading and refining of bitumen and crude oils is such a big contribution to life cycle GHG emissions, it is important to accurately determine yields and energy consumption in these areas. Modeling the conversion of each crude oil or bitumen to transportation fuels was done in a representative upgrader and refinery using nonlinear simulation software. Utility and yield models were used that have been well-tested in engineering studies for bitumen upgraders and refiners who process a wide variety of crude oils.

Other Issues

System Boundaries

A key aspect of life cycle analysis is the definition of the system boundaries, which will identify what emission sources are included in the analysis and, more importantly, how indirect impacts are treated. Some of the key indirect impacts include how to handle:

- Petroleum coke, residual oil, and other non-transport fuel byproducts
- Marginal versus average energy inputs for process electricity
- Vented and flared associated gas from crude oil production

Coproducts

Modern oil refineries produce a variety of fuels and other coproducts. Gasoline, diesel, and kerosene are the primary transportation fuel products, while LPG and residual oil are also used as fuels for heating, power generation, and transport. Refineries also produce coke and sulfur as coproducts, and some produce asphalt. More advanced refineries supply feedstocks for the petrochemical industry as well. Properly attributing energy inputs and emissions to coproducts is

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a significant concern in life cycle analysis because different attribution methods can lead to quite different results for any given product or process.

Transportation of Crude Oils, Bitumen and Refined Products

The energy consumption and GHG emissions from transportation of crudes and refined products is dependent on the type of material transported, the mode of transport, and the distance. The calculation method in GREET was used and updated as needed with industry estimates to determine GHG emissions from transportation. Because the GHG emission impact from transportation of crude oils and refined products is much smaller than the impact from other steps in the life cycle of crude oil and bitumen derived oils (see Figure 1-2), any error in overall LCA from this approach will be small.

Vehicle Fuel Consumption

GHG emissions from transportation fuel consumption are the major sources of GHG emissions in the crude oil life cycle assessment. These emissions include CO_2 from fuel combustion as well as low levels of CH_4 and N_2O. Because the GREET model is designed with a sophisticated mix of vehicle, fuel, and engine technology, we used the power of the model to determine transportation fuel GHG emissions in the overall life cycle assessment rather than augment the model with other data. The emissions produced from the combustion of transportation fuel of a given quality and specification also will not vary significantly as a function of crude oil type because transportation gasoline and diesel fuel must be produced within a narrow range of specifications.

Crudes Evaluated in Study

The following crude oils, bitumens and SCOs were evaluated in the Study:

- Arab Medium—Saudi Arabia
- Kirkuk—Iraq
- Bonny Light—Nigeria
- Maya—Mexico
- Bachaquero—Venezuela

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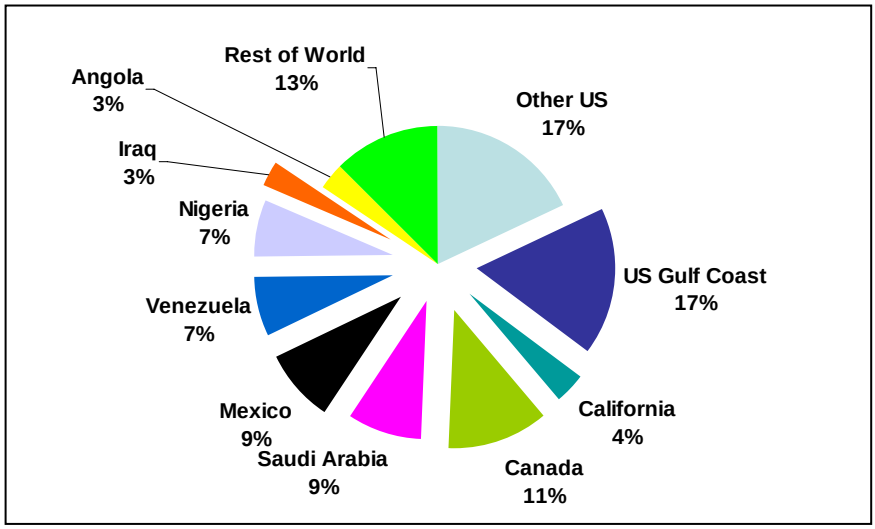
- Mars—US Gulf Coast
- Kern River / SJV—California
- Oil Sands Bitumen—Canada—with and without refining diluent to gasoline
- SCO from a coking-based upgrader in Alberta, Canada
- SCO from an ebulating bed-based hydrocracking upgrader in Alberta, Canada

As shown in Figure 1-5, these crudes are representative of the majority of crudes processed in the US.

Figure 1-5.
US Crude Supply



EIA, U.S. Imports by Country of Origin for 2007

Report Organization

The major sections of the report follow the steps in well-to-wheels analysis. Sections are organized as follows:

- Life cycle methodology
- Crude oil and bitumen production
- Upgrading of bitumen to synthetic crude oil

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- Transport of crude oil, synthetic crude oil and bitumen to the refinery—will be combined with delivery section
- Refining of crude oil, SCO, and bitumen to transportation fuels
- Delivery of refined products to vehicle tank
- Combustion of fuel in the vehicle
- Well-to-Wheels results from converting crude oil and bitumen to transportation fuels

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GREET

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World Bank, Table 4, *Gas flaring data from A Twelve Year Record of National and Global Gas Flaring Volumes Estimated Using Satellite Data, Final Report to the World Bank,* May 30, 2007.

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Section 2.

Life Cycle Analysis Approach

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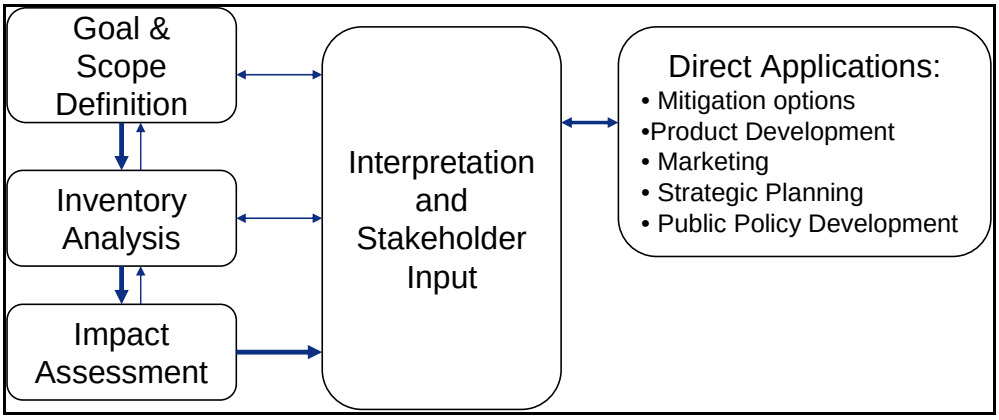
Life Cycle Methodology

This study calculates life cycle GHG emissions of petroleum fuels with additional detail to accurately distinguish the effects of different petroleum types, extraction technologies, reservoir locations and transport mode, and processing options. The overall calculation approach is the same as that applied for other fuel life cycle analysis studies (Wang 2008b, Edwards, ARB 2009a). Emissions are summed over all of the steps from crude oil extraction to vehicle end use, including the impact of co-products. The scope of the emissions calculations and basis for comparison is defined within our overall procedure for life cycle analysis.

This Study generally follows the steps outlined by ISO requirements for Environmental management in 14040 Life Cycle Assessment—Principles and framework and ISO 14044—Life cycle assessment—Requirements and Guidelines. Figure 2-1 illustrates the stages in the life cycle assessment. The project team followed these steps by identifying analysis requirements at the planning stage of the project, reviewing the project plan with a stakeholder advisory team, following the progression of activities from developing scenarios, analyzing the life cycle inventory for components in the fuel cycle, and performing an overall life cycle assessment.

Figure 2-1.
Stages of an LCA



The project advisory team consisted of participants from the oil industry, oil sands project developers, Canadian and US energy agencies, and academia. The advisory team members are identified in Table 2-1. A more detailed list of stakeholder participants is provided in Appendix I. The project team met with the advisory team during several project review meetings to review interim progress and the study approach. Two public meetings were held to present interim and draft final results (Table 2-2). The project review meetings were held at AERI offices in Calgary and the public meetings were held at Suncor's facilities in Calgary.

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Table 2-1.
Project Advisory Committee

Organization
AERI
Alberta Energy
California Energy Commission
Nexen
Shell
University of Calgary

Table 2-2.
Project Review Meetings

Meeting Date	Topic
24 Sept 2008	Project Kick Off
11 Oct 2008	Review Upgrading Approach
6 Nov 2008	Review Refinery Modeling Approach
10 Dec 2008	Review Refinery Modeling Approach and discuss approach for Oil Production
18 Jan 2009	Review Oil Production, Preliminary Results
10 Feb 2009	Review Oil Production
13 March 2009	Public Draft Results
15 June 2009	Public Final Results

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Fuel Cycle Steps

The life cycle analysis of oil and bitumen production, bitumen upgrading, and refining options includes the emissions associated with resource extraction through vehicle operation. The emissions were calculated on a consistent basis for a range of crude oil types and bitumen processing options. This Study compared the life cycle emissions from producing and consuming transportation fuels produced from oil sands, conventional, and heavy crude oils for a range of crude types and processing options. This analysis is consistent with California's LCFS, which may also be applied to other states in the US and Canadian provinces. Because of California's long history with fuel cycle analysis as well as its experience using the GREET model, the analysis in the Study took into account many of the learnings and developments that have come from prior LCA analyses.

GHG emissions are summed using the same energy accounting system as in the GREET model. The life cycle inventory for each step in the fuel cycle is based on analysis defined in this Study. The life cycle emissions for each upstream fuel cycle inventory component step are based on values from the GREET model.

Processing Steps

The first step is resource extraction, which may be crude production from a well, for example, or bitumen production via mining or steam assisted gravity drainage (SAGD). This step also takes into account the emissions from associated gas production and flaring. Next is initial processing, which may include separation of light ends from conventional crude or field processing and upgrading of bitumen. The resulting conventional crude oil or synthetic crude oil is next transported to refineries. Different crude oil sources require different levels of energy to extract and convert them to transportation fuels and may therefore have very different life cycle greenhouse gas impact. A significant portion of the impact may be associated with the production of coproducts such as residual oil and coke. Finally, fuels are moved to market for consumption in vehicles. The vehicle's contribution to the well-to-wheels emissions is primarily associated with carbon in the fuel.

The overall life cycle for crude oil is shown in Figure 1-1 of Section 1. The well-to-tank (WTT) phase corresponds to resource extraction through refining and delivering the fuel to the vehicle. The tank-to-wheel (TTW) phase includes vehicle emissions—both CO_2 associated with fuel carbon as well as methane and nitrous oxide produced during the combustion process.

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Life Cycle Criteria

GHG are counted for the primary pollutants affecting global warming from transportation fuels. The three main greenhouse gases—carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)—have global warming potential (GWP) that enables the calculation of an aggregate figure for different emission species. GWP values are developed by the Intergovernmental Panel on Climate Change (IPCC) and released in their latest report (IPCC 2007). The factors, shown in Table 2-3, indicate the grams of CO_2 equivalent compared with 1 gram emission of the indicated gas. Hydrocarbon and CO emissions are represented as CO_2 on a carbon content basis as these pollutants oxidize to form CO_2 in the atmosphere within a few days. The GREET model uses the same approach for hydrocarbon and CO emissions.

Table 2-3.
IPCC Designated Global Warming Potentials for Conventional Greenhouse Gases (IPCC 2007)

Emission Species	Global Warming Potential (GWP)
CH_4	25
N_2O	298
CO_2	1

The GHG impact for transportation fuels includes both the WTT and TTW components. The functional unit for the analysis is 1 megajoule MJ of gasoline or diesel transportation fuel represented through vehicle end use on a lower heating value (LHV) basis. The combustion emissions include the fossil carbon in fuel (expressed as CO_2) and vehicle methane (CH_4) and nitrous oxide (N_2O) emissions. Note that the vehicle CH_4 and N_2O emissions are also expressed on a per MJ basis.

Scope and Definition

The scope of the Study covers the calculation of GHG emissions from a variety of conventional and unconventional crude oil resources and Canadian oil sands. The focus of the Study is on technologies that are being implemented today. Thus new bitumen extraction technologies as well as potential new upgrading or refining technologies were not investigated.

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Analysis Cases

The Study analyzed a range of petroleum production options, including the refining of crude oils and bitumen produced by conventional and unconventional means. The analysis cases, shown in Table 2-4, cover a range of crude types and processing options. Both surface mining and thermal recovery were examined for the Canadian oil sands cases. Heavy oil from California is produced by thermal methods.

Table 2-4.
Analysis Cases Showing Variations in Oil and Bitumen Production and Processing Options

Feedstock	Extraction	Upgrading	Refining	Feedstock Location	Upgrader Location	Refinery Location
Venezuela – Bachaquero	Conventional with steam assist	--	Base Refinery, FCC	Venezuela Lake Maricaibo	none	Chicago
Mexico – Maya	Conventional with N2 injection	--	Base Refinery, FCC	Cantarell field Gulf of Mexico	none	Chicago
Saudi Arabia – Arab Medium Crude Oil	Conventional with water flood	--	Base Refinery, FCC	Saudi Arabia	none	Chicago
Conventional crude oil from the U.S. Gulf Coast – Mars	Conventional off shore rig With water flood	--	Base Refinery, FCC	Mars Platform US Gulf Coast	none	Chicago
Nigerian – Bonny Light	Conventional – high flaring of gas	--	Base Refinery, FCC	Nigeria	none	Chicago
Iraqi Crude Oil – Kirkuk	Conventional with water flood	--	Base Refinery, FCC	Kirkuk Iraq	none	Chicago
California thermal heavy oil – Kern River, San Joaquin Heavy	Thermal enhanced oil recovery	--	Base Refinery, FCC	Bakersfield	none	Los Angeles
Canadian Oil Sands	SAGD	Delayed Coker, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	Surface Mining	Delayed Coker, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	SAGD	Ebulating Bed, SCO	Base Refinery, FCC	Ft McMurray	Edmonton	Chicago
Canadian Oil Sands	SAGD	Bitumen direct to refinery – diluent to refining	Base Refinery, FCC	Ft McMurray	none	Chicago
Canadian Oil Sands	SAGD	Bitumen direct to refinery – diluent returned to Canada	Base Refinery, FCC	Ft McMurray	none	Chicago
Canadian Oil Sands	Surface Mining	Bitumen direct to refinery – diluent returned to Canada	Base Refinery, FCC	Ft McMurray	none	Chicago

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Goals and Objectives

The primary objectives of this Study were to:

- Understand and document the treatment of oil sands versus other conventional crudes being processed in the US as currently represented in GREET.
- Prepare a defendable comparison of WTW (well-to-wheels) GHG emissions for oil sands bitumens vs. specific crude oils.
    - Add enough fidelity to evaluate and compare specific crude oils and pathways from production through motor fuel products (production, transport, upgrading, refining, consumption in the vehicle)
    - Set boundaries to fully encompass all major GHG emission contributors (*e.g.* flaring of coproduced gas, fuel oil, coke)
- Understand differences in a rigorous comparison of different crude oils and processing pathways vs. the GREET model defaults.
- Establish a basis for the next phase of work to evaluate the means to mitigate any identified GHG penalty for oil sands (carbon capture and storage, alternate fuels / combustion technology, configuration, *etc*.)
- Enhance generic WTW Life Cycle Assessment of transportation fuel production and consumption with an assessment that more properly reflects differences between crude oil production, upgrading, refining, and potential for GHG mitigation for a representative basket of benchmarking crudes processed in the United States.
- Ensure transparency of results, methodology and underlying data.
    - Use public and defendable data sources
    - Use recognized and transparent LCA methodology and model—similar to what is used in California for LCFS and other well-vetted life cycle studies

System Boundaries

The definition of the system boundaries identifies which emission sources are included in the analysis and, more importantly, how to treat indirect impacts. Some of the key indirect impacts include how to handle:

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- Petroleum coke, residual oil, and other non-transport fuel by-products
- Marginal versus average energy inputs for process electricity
- Vented and flared associated gas from crude oil production
- Captured and sequestered CO_2

System boundaries for transportation fuel pathway are shown in Figures 2-2 to 2-4 for conventional crude, bitumen and dilbit, respectively. Since the goal of the Study was to determine the differences associated with different oil sources, this analysis focused on energy inputs and emissions from operations. Included here are the energy inputs to the oil production system, including the energy inputs and emissions associated with producing feedstocks such as electric power and natural gas.

Emissions associated with labor, equipment production and recycling are not considered here because they are not within the scope of the life cycle analysis considered under the LCFS. Calculating emissions associated with materials and facilities introduces uncertainty associated with project life and recycling. The focus of the study was to assess the impacts of oil extraction and processing representative of an ongoing concern. Also not included in this study are emissions associated with tailing ponds used to store surface mining effluent or land clearing associated with the establishment of surface mines. These emission sources are being studied elsewhere and are often grouped into the analysis of direct and indirect land use.

The life cycle analysis included all of the steps in the fuel cycle with the focus on gasoline and diesel production. The energy inputs and emissions for the refining components, the upgrader and oil refinery were based on Jacobs Consultancy's modeling of generic facilities. The analysis determined energy inputs and emission burdens for all of the refinery products and coproducts. The distribution of emissions associated with coproducts is discussed below.

Geographic Boundaries

The geographic location of feedstock resources, production facilities, and end use affect the overall life cycle analysis due to the requirements for fuel transport. Local emission constraints also have a significant effect on emission control requirements, which affect criteria pollutant emissions as well as venting and flaring of associated gas. This study takes into account the following factors associated with the geographic location of petroleum resources:

- End use fuel is consumed in US PADD 2 (Midwest) with either Canadian oil sands products or various crude oil types transported to PADD 2 for refining

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- o A change in the output of Canadian oil sands products could be met by an increase in imports of other crude types to PADD 2
- o Examine California thermal heavy oil for end use in California

- Feedstock transport to PADD 2 refineries (Chicago)
- Associated gas venting and flaring consistent with region of oil production
- Average US criteria pollutant emission factors
  - o Even though criteria pollutant emissions will be higher outside the US and Canada, the impact of emission controls on GHG emissions is less than 1%
- Resource assumptions for electricity and natural gas that are consistent with the locations for feedstock production and oil refining

Figure 2-2.
System Boundary—Conventional Crude

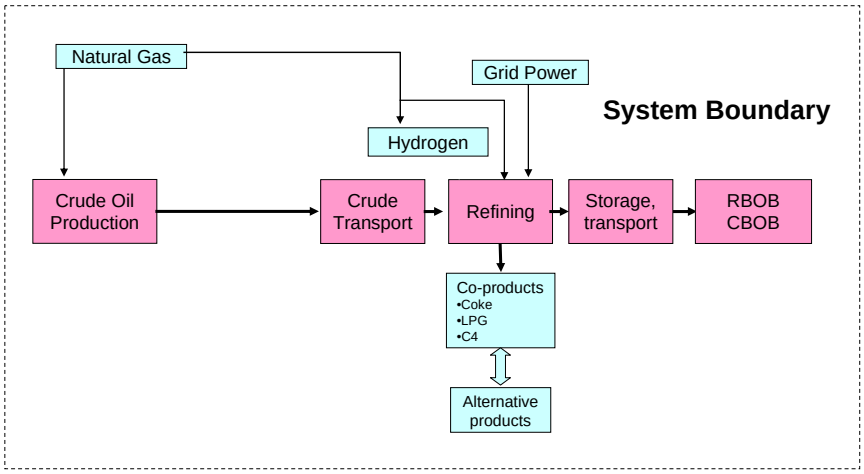

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Figure 2-3.
System Boundary—Bitumen

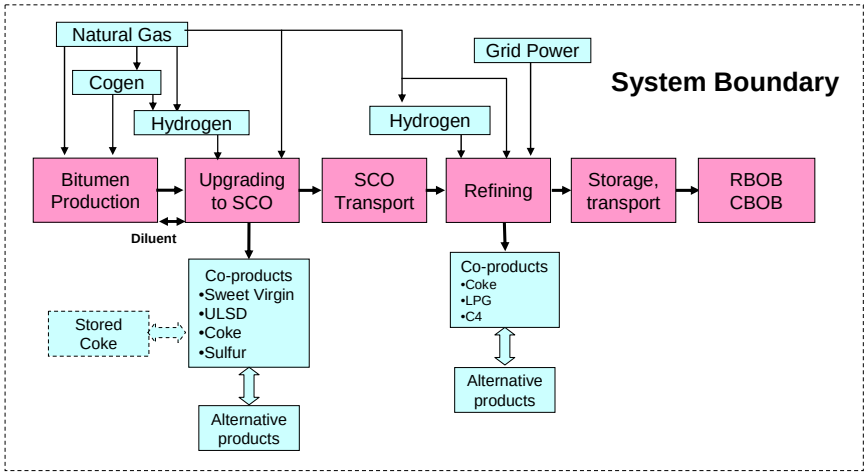
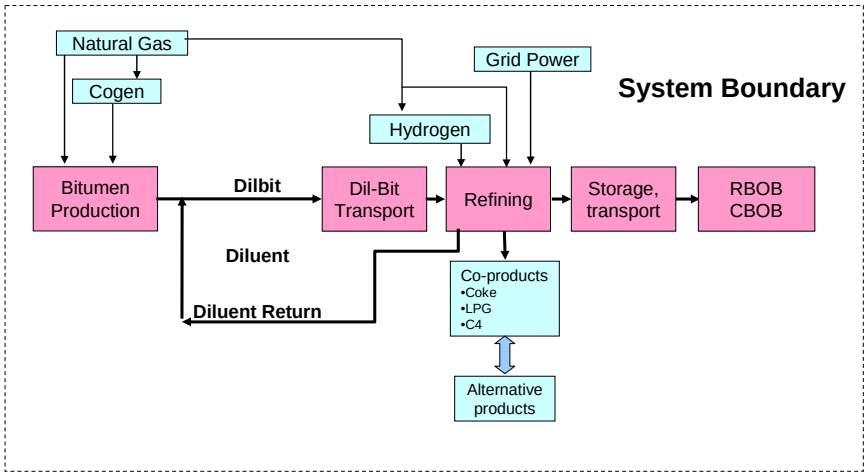


Figure 2-4.
System Boundary—Dilbit



Disposition of Coproducts

Modern oil refineries produce a variety of fuels and other coproducts. Gasoline, diesel, and kerosene are the primary transportation fuel products, while LPG and residual oil are also used as fuels for heating, power generation, and transport. Refineries also produce coke and sulfur as coproducts; some refineries also produce asphalt. More advanced refineries supply feedstocks for the petrochemical industry as well.

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Attributing energy inputs to refined products is a challenging exercise complicated by the requirements of producing different products. For example, a crude oil distillation unit separates crude oil into different product streams to enable the refining of all refinery products while an alkylation unit operates to produce only higher-octane components for blending into gasoline. Several approaches have been considered for attributing refinery energy inputs and emissions to fuel products.

Different methods have been used to define the method for assigning emissions to coproducts. These methods fall into two categories:

- Substitution—This approach estimates the first order market effects of producing co-products by subtracting from the LCA the impacts presumed to be avoided by substituting the co-products for other products that provide the same function.

- Allocation—This approach assigns a portion of the inputs and outputs within a production system among the various co-products based on either process simulations, or based on physical or economic attributes such as mass, energy content, or market value.

In general, a substitution method is preferable because it accounts for the life cycle of the fuel and the coproduct, while an allocation method does not take into account the actual impact of the coproduct. In the system expansion approach, the LCA system boundaries are expanded to include the substitute product. Unfortunately, expanding the analysis can introduce additional uncertainty into the life cycle analysis of the original fuel product, and expansion may beget further expansion to address coproducts of the substitute.

Properly attributing energy inputs and emissions to coproducts is a significant concern in the life cycle analysis because different attribution methods can lead to quite different results for any given product or process. Handling coproducts properly, however, is challenging. Some of the issues relating to life cycle analysis of transportation petroleum fuels include:

- Multiple products, including gasoline, diesel, and LPG, are candidate transportation fuels.
- Residual oil by-product has potential use for ship fuel and power generation.
- Petroleum coke can be used as a substitute for coal in electric power production, or used in making steel and aluminum. It is also evaluated as a source of steam for in-situ bitumen production and as a source of hydrogen for upgrading and refining.

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- Determining changes to refinery output and emissions for different crude slates requires complex modeling.

The simplest coproduct strategy is to assign all refinery emissions and all of the combusted energy to transportation fuel products in proportion to the energy content of the gasoline, kerosene, and diesel produced. This is essentially the energy allocation method, applied to transportation fuels with the understanding that residual oil and LPG are not the primary products of the refinery, as substitutes with less energy input are readily available. For example, crude oil could be directly fired in power plants and used as marine bunker fuel (with appropriate safety measures to manage the emissions).

This approach does not distinguish between the energy intensity of gasoline or diesel production and more importantly, it does not allow for an assessment of the production of different types of gasoline or diesel fuel as the refinery impacts would be commingled between gasoline and diesel.

Another approach that is frequently used involves the attribution of the energy from different refinery units to intermediate product streams in order to develop a process based allocation scheme. Several studies use this approach (Unnasch; Wang, Wang (a). Each of these studies estimates the energy consumption and emissions from different refinery units and assigns them to refinery products. In cases where multiple products are produced, the energy inputs and emissions are distributed among the different product streams corresponding to each refinery unit based on its function, energy, volume, or mass of output, and mix of products. Much of this prior work suffered from insufficient information regarding yields and energy use at the fundamental processing level in refineries. Furthermore, this work lacked information about the interconnections between process units and the processing routes of many intermediate products.

Oil refineries produce a variety of products using different processes within the refinery to separate product streams, remove sulfur, convert hydrocarbons to high octane, and many other functions.

Some attempts at coproduct attribution have also been made with linear programming modeling of refineries (Tehrani, Edwards). Such modeling efforts attempt to isolate the emissions associated with a single product such as gasoline or diesel.

This Study applies a system expansion approach that assigns the process level emissions to each refined product and assigns a substitute value to coproduct coke and light hydrocarbons. The different coproduct levels are examined for each oil processing pathway.

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Impact of Petroleum Coke

The production of petroleum coke can vary significantly among crude oil and oil sands processing options. Coke varies with the type of processing. More coke is produced from a conventional coker and less from more hydrogen-intensive options, which produce more products and less coke. Less energy-intensive processing options also result in lower GHG emissions per unit of refined product, which presents challenges in assessing the overall impact of oil sands derived fuels.

This Study assumes that coke produced at the upgrader is stored. Coke produced at the refinery is assumed to be used as a substitute for coal in electric power generation.

It was agreed with AERI and other stakeholders that emissions from the production of coke will be distributed to the major products, which are gasoline and ULSD. In addition, for coke that is a substitute for coal, differences in GHG emissions for using it instead of coal will be assigned to the major products. These emissions include any transportation differences between coke and coal.

Average vs. Marginal Emissions

Rather than use an average GHG emissions for producing conventional crude oils and crude oils derived from oil sands, the project team determined the energy consumed and GHG emissions for each crude type, the GHG emissions from shipping and storing each crude type, and the GHG emissions from converting each crude oil to transportation fuels and distributing these fuels to the vehicles. This approach ensures that each product receives its proper share of GHG production burden, which will depend on the feed burdens and the processing intensity to make the product.

Note Regarding Methodology: This Study primarily considered WTW direct emissions. The emissions that may arise from land use, resource exploration, the building of infrastructure and facilities, manufacturing and disposal of heavy equipment, etc. is beyond the scope of this work. The treatment of co-products such as petroleum coke and cogenerated electricity is complex, and this Study treated such emissions in a preliminary manner to indicate the need for more rigorous and comprehensive analysis in future work.

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LCA Model Scope

Several well-known LCA models are typically used for life cycle analysis. GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) was developed by Argonne National Laboratory; GHGenius was developed in Canada. Both models are publicly available. In addition, a number of companies have developed and use their own proprietary models. Jacobs Consultancy used GREET for this Study due to the following:

- GREET is supported by Argonne National Laboratory and has been used extensively in previous US evaluations, including the development of the CARB LCFS. It is considered the “gold standard” in the US.
- GREET is highly transparent and defendable (with clear treatment of processing steps)
- GREET is being used and evaluated by various Canadian LCA experts

The GREET model includes a variety of petroleum and non-petroleum pathways. The configuration of the model treats pathways on a consistent basis with a calculation of average energy inputs and emissions. The default values represent aggregate results for petroleum and alternative fuels that represent the average for US production. The model also calculates emissions for new fuels, where the process assumptions reflect new facilities while the petroleum resources reflect the average.

GREET models the energy inputs and emissions from oil production and refining based on the average for the US industry. The underlying assumption is that new oil, electricity, and other energy resources will consist of a comparable resource mix as existing resources. Default GREET inputs and the overall model structure do not reflect marginal fuel production or the impact of new fuels and savings in fuel usage. Heavy oil and unconventional oil represent an increasing share of the market as the supply of conventionally produced oils declines.

GREET inputs are intended to represent the US average values for both production and refining. Crude oil production assumptions reflect the aggregate US statistics (USDOC), and are represented as a crude oil extraction efficiency of 98 percent. Refinery emissions in GREET are based on a refinery efficiency input derived from EIA statistics (Wang 2008a). Because this Study evaluated the emissions from oil production, upgrading, and refining, in greater detail than supported by the GREET model, the calculations were performed external to GREET. Crude oil and refined product transport emissions were calculated using the calculations in the GREET model. Similarly, the upstream fuel cycle associated with natural gas production and power generation are calculated using GREET. The upstream fuel cycle component is significant because it is not included in GHG reporting from oil producers.

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Section 3.

Crude Oil and Bitumen Production

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Crude Production

Oil production is typically the first step in a life cycle analysis of petroleum fuels. Oil production covers a range of technologies depending on the reservoir type, extraction technology, and oil field equipment. In addition, oil production requires exploration to find the oil, which is typically not included in life cycle analyses. This section examines the data on oil exploration, drilling, and production.

Over the years, oil production has involved progressively more intensive exploration, drilling, and collection activities. Early oil production activities involved identifying oil seeps and drilling relatively shallow wells. Today's oil exploration activities include sophisticated seismic technologies that detect underground (and in deep water) geological formations. Accessing the oil has also become more difficult. For example: Chevron, Devon, and Statoil recently announced a very large oil discovery in the Gulf of Mexico, which could increase US proven reserves of oil by as much as 50 percent. However, exploring this source of oil would involve drilling 20,000 feet deep (under 7,000 ft of water) and require significant energy, which would thereby generate significant GHG emissions.

Petroleum production is often divided into three general methods of oil recovery: primary, secondary and tertiary.

- *Primary recovery* produces oil using the pressure of the oil reservoir. It may be enhanced by gas or water injection to maintain the reservoir pressure. A pump may be used to lift the crude, or gas lift may be used to increase oil recovery. The gas reinjected may be part of the associated gas or the CO_2 portion that is produced along with the crude oil, or it may be imported natural gas or nitrogen.
- *Secondary recovery* methods pump water into the reservoir to sweep trapped oil into collector wells. Secondary recovery is often the next step when production begins to decline during primary recovery. In many newer wells, water is injected from the beginning of production to better manage the reservoir and enhance oil recovery.
- *Tertiary recovery* methods use steam or CO_2 to reduce the viscosity of the oil and thereby increase production. Tertiary recovery is more expensive than primary and secondary recovery and is generally not practiced unless oil production by other means is no longer feasible. In the case of ultra-heavy crudes and bitumens, especially in Canada, tertiary recovery is often practiced from the beginning of production. Steam injection is used to recover ultra-heavy crudes. It is used in Venezuela, Mexico, and in the central valley of California to enhance crude oil recovery. Bitumen in Canada is also produced by mining.

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The distinction between primary, secondary, and tertiary recovery is somewhat loose. Is it secondary recovery when water is used to repressure a reservoir? Is it tertiary recovery when CO_2 is removed from the associated gas and reinjected into the reservoir? Furthermore, if heavy oils and bitumens are produced by steam injection from the start of production, is this tertiary recovery?

GHG emissions from crude oil production are strongly dependent on the energy needed to produce the oil. This includes the energy to lift the oil from the reservoir, to treat the gas and water that are produced, as well as to treat water or gas that is reinjected, and to pump the water or compress the gas that is reinjected. In addition, GHG emissions from crude production are strongly influenced by emission or flaring of produced gas, also called associated gas. Access to outlets for produced gas and restrictions on flaring vary from country to country.

Many of the parameters that affect GHG emissions change over the life of the reservoir. Reservoir pressure often decreases, gas production generally decreases, water production often increases, and crude production generally decreases over the life of the reservoir. In addition, it may be necessary to inject gas, water, or even nitrogen, CO_2 or steam to enhance oil recovery as reservoirs age.

Information about energy use and GHG emissions from crude oil production is not readily available. In addition, information about the parameters that affect energy use and GHG emissions—such as the water to oil ratio, gas to oil ratio, water or gas reinjection rates, water treatment, flaring, or emissions of produced gas—is not readily available for a number of reasons. One significant reason is that publication of parameters that describe crude oil production, such as the quantity of water or gas produced, which are represented by the water to oil and gas to oil ratios, gives competitors insight about the reservoir condition. Likewise, for information about water flooding and gas injection. Saudi Arabia does not publish any information about its reservoirs to avoid speculation about the viability of its oil supply, which could affect oil markets.

Another reason for the lack of information about energy use and GHG emissions from crude production suitable for a life cycle analysis is that this information is not routinely measured by producers. Additionally, data that are provided are often aggregated, making it difficult to put it in a format suitable for a life cycle analysis.

Crude Production Model

To close the information gap and to put the energy used and GHG emissions from oil production around the world on a more consistent basis, a model of the fundamental steps in crude oil

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production was developed for this Study. A schematic of the operations in the crude production model is shown in Figure 3-1.

There are four fundamental operations in crude production:

- *Lifting the crude and any associated water and gas from the reservoir*—Crude is produced under reservoir pressure or by mechanical means (pumping or gas lift) or a combination of both. Reservoir depth and pressure determine when it is necessary to use mechanical lifting. Crude oil is generally produced as a mixture of oil, water and gas which must be separated.
    - Reservoir pressure is determined by the pressure of gas and water in contact with the oil. Oil production generally reduces reservoir pressure over time. Gas or water can be injected to maintain reservoir pressure.
    - Mechanical lifting by pumping or gas lift is used to increase oil production when the reservoir pressure is insufficient. The energy for pumping is determined by the reservoir depth; the weight of oil, water and gas that must be brought to the surface; and the pipe diameter. Most of the energy to lift the crude is determined by the depth of the well. Pumping is either by a pump located on the surface or in the well (downhole). Gas lifting consists of injecting gas at one or more points in the production tubing with the effect of reducing hydrostatic head. In this analysis it was assumed that pumping is the major force for bringing oil to the surface. Pumping energy is based on: turbulent flow for friction drop of 0.1 psi per 100 feet, through a 3-inch production pipe; reservoir depth; crude density; and flowrate. The energy for mechanical lifting is supplied by electricity, either generated onsite from produced gas, imported natural gas or diesel fuel, or grid-based electricity. The energy source is a key factor in determining GHG emissions. This analysis assumed that electricity is supplied by onsite power generation using produced gas supplemented when necessary by imported natural gas. There is more about onsite power generation in a subsequent section.
    - *Separating the crude from the gas and water*—The mixture of oil, water, and gas produced from the oil well must be separated before the oil can be sent to the stock tanks. Separation takes place in a separator, which consists of a horizontal separator with internal baffling to separate gas, hydrocarbon liquid, and water. Produced gas goes to gas treatment, oil goes to the stabilizer, and water goes to treatment. There is very little energy used in separation. The gas from the separator (consisting of C_1s, C_2s, H_2S, CO_2, and a small amount of C3s and heavier) is compressed, dehydrated and treated for H_2S removal and, depending on quality, further treated to remove CO_2. The resulting gas is sent out as a product, or reinjected into the reservoir to maintain pressure. The C3s and C4s will be either sold or reinjected.

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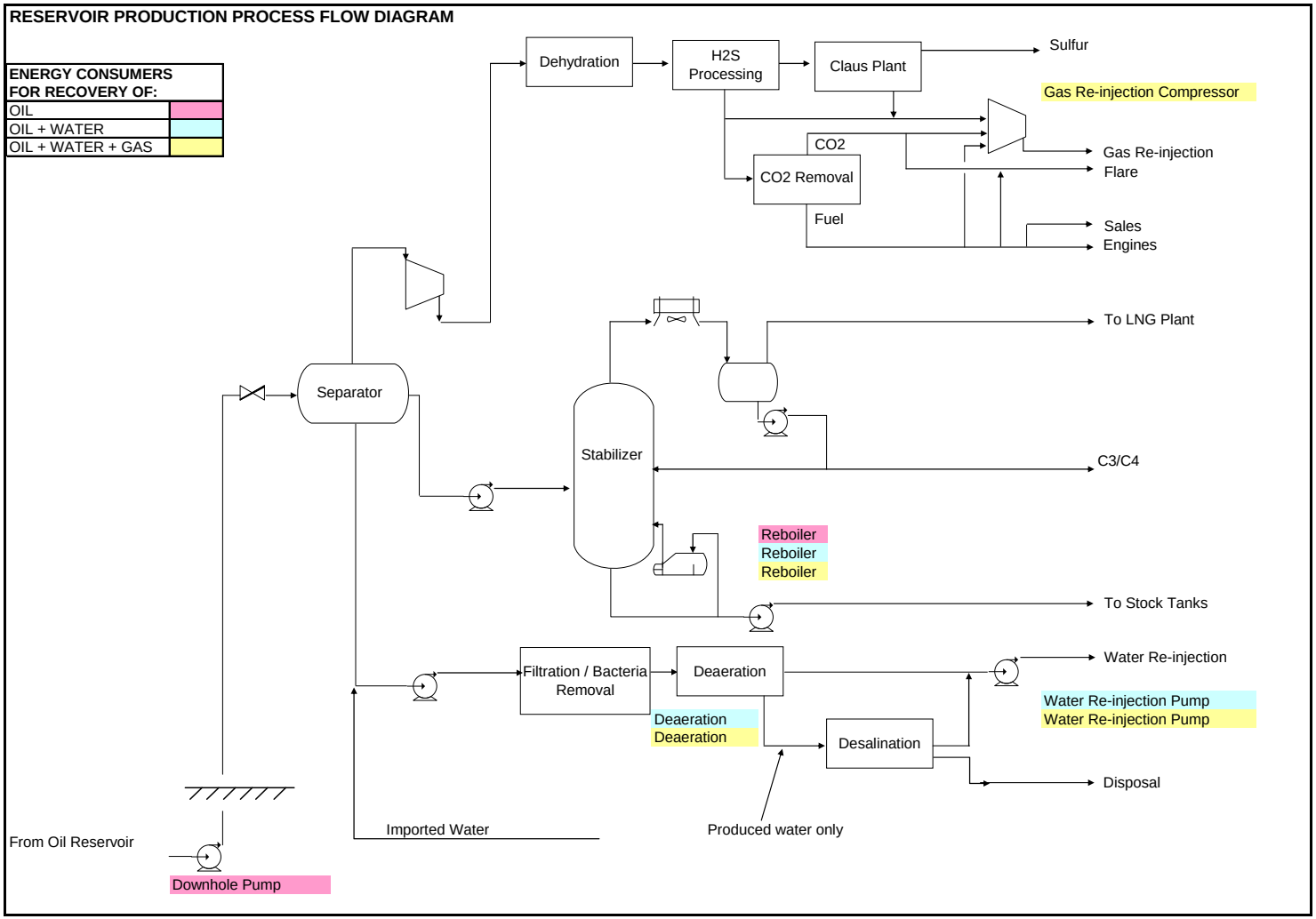
Figure 3-1.
Crude Production Schematic



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- *Treating the crude, gas and water*
  - Crude Stabilization—Crude oil from the separator may contain a small amount of light components (C1s - C4s) that must be removed before the oil goes to the stock tanks. The stabilizer consists of a non-refluxed trayed distillation column operating around 50 psig. For safety, reboiler heat is supplied by electrical heating instead of by direct firing. As with mechanical lifting, electricity is either supplied onsite or imported from the grid. Our analysis assumes power is generated onsite. Crude from the separator must be stabilized by removing light components, C3s and C4s and any remaining C1s and C2s. The gas can be reinjected into the reservoir, or sold as a product.
  - Water Treatment—Water produced from the reservoir or brought into the production site from outside must be treated. Produced water is often brackish and contains residual oil. It must be treated before disposal to remove salts and oil. Water that will be reinjected—either produced water or water brought in from outside—must be filtered to remove particulates and must be deaerated. The major energy use in water treatment is for deaeration. Water produced from the reservoir must be treated before disposal or reinjection. Water brought in from outside to repressure the reservoir or for use in secondary recovery must also be treated. Treatment may include filtration, deaeration, or desalination.
    - Filtration and Bacteria Removal—Filters are used to remove particulates. Energy for filtration is based on pumping to 150 psi, which adds a small amount to overall energy.
    - Deaeration—Assumes vaporizing 5% of the water. Energy is supplied by electric heating.
    - Desalination—Water is desalinated as needed to meet the quality of water standards for reinjection or disposal. Water treatment was assumed to be done by reverse osmosis or vacuum evaporation. Energy is primarily based on pumping, which requires 0.009 kWh per gallon of water.
- *Reinjecting the water and gas to maintain reservoir pressure*
  - Water Reinjection—Energy for water reinjection is based on the quantity of water to be reinjected and the reservoir pressure. Energy for pumping is supplied by an electric motor.
  - Gas Treatment—Produced gas must be treated before it can be sold, used in onsite power generation, or reinjected. It must first be dehydrated to remove residual water. Next, H_2S must be removed to reduce corrosion and to meet product specs; it may

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or may not be necessary to remove CO_2. H_2S that is removed is converted to sulfur in a Claus plant. The sulfur-free gas will then be compressed.

- Dehydration—A glycol absorber removes water from the gas. Energy use is determined by the amount of water in the gas, which sets the glycol circulation rate and the energy needed to regenerate the glycol. The basis for the glycol absorber is from the NGPSA handbook.
- H_2S removal—H_2S is removed from the gas in an amine absorber [monoethanolamine (MEA) was assumed]. Energy is needed to circulate the amine and to regenerate it. Design parameters are from the NGPSA handbook.
- Claus Plant—Sulphur recovery in a Claus plant is auto-thermal; no energy is needed.
- CO_2 Removal—CO_2 is removed in the amine absorber. The design and operating parameters are from the NGPSA handbook . The technology is the same as for H_2S removal.
- Gas Disposition—Produced gas from treatment is either sent to products, used to generate electricity onsite, reinjected, or flared. Compression is the major source of energy use. Flaring and venting of gas do not use energy but are major sources of GHG emissions.
- Compression—Energy for compression is determined by the quantity of gas to be compressed and, if reinjected, the reservoir pressure.
- Venting and fugitive losses—Some produced gas is lost during crude oil production from the well casing, mechanical seals, and valves. The amount of gas that is lost is usually not more than 5 percent. The contribution to GHG emissions is mainly from the methane and CO_2 in the produced gas.
- Flaring—Gas flaring occurs in locations that do not have strict environmental standards or outlets for produced gas. The GHG burden from flaring is determined by the GHG emissions from gas combustion together with any emissions from gas that bypasses combustion.
- Miscellaneous energy accounts for the multiple small users of energy, such as lighting for the production site and offices, electricity for living quarters, security, instrument air, small metering pumps, *etc*. In our analysis, 10% was added to the total energy to account for miscellaneous energy.

The major sources of emissions of GHG are shown in Table 3-1.

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Table 3-1.
Major Sources of Energy Use and GHG Emissions in Crude Production

Pumps	Downhole Pump Water Re-injection Pump Diluent Pump
Reciprocating Compressor	Gas Lift Gas Re-injection
Heaters	Crude Stabilization Reboiler @ 10% vaporization Water Deaeration @ 5% vaporization
Glycol Dehydrator for Water Removal from Gas	Heater in Glycol Treater Pumps in Glycol Treater
Amine Treater for CO_2/H_2S Removal	Heater in Amine Treater Pumps in Amine Treater
Water Treatment	Reinjected Water Water Discharge
Direct Venting	Vented Produced Gas Fugitive Produced Gas
Gas Flaring	Flared Gas
CO_2 Venting	CO_2 Venting
Miscellaneous Energy	Lighting, offices, labs, maintenance, security, instrument air, storage, small pumps, *etc*.

Power to the equipment used in crude production can be supplied from onsite generation or from the grid. Onsite generation uses produced gas supplemented by natural gas or diesel fuel brought in from offsite when there is insufficient produced gas. Generators are driven by reciprocating engines—spark ignition when gas is used, compression ignition when diesel fuel is used.

Fuel demand is based on the efficiency of the fuel use in the engine, the efficiency of electric power generation, the efficiency of the pump, compressor, and electric heater. Fuel consumption was taken from Caterpillar technical information (Caterpillar). Generation efficiency for diesel and gas-powered generators was assumed to be 75%; pump efficiency was assumed to be 65% (NGPSA Chapter 12, Page 4); and compressor efficiency was assumed to be 85 percent.

The next step is to convert the energy used and gas emissions in flaring and venting to GHG emissions and report the results on the basis of weight of GHG emissions per barrel, metric ton, or MJ of crude produced. For this analysis, the reporting basis is g of GHG emissions per MJ of crude. GHG emissions are reported on a CO_2 equivalent global warming potential (GWP) basis.

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GHG emissions depend on how the fuel is used and on the composition of the gas. Emission factors for gas-powered and diesel-powered generators are from the California GREET model shown in Table 3-2.

Table 3-2.
Emission Factors—Electricity Generation

Engine/ Fuel		Stationary Reciprocating Engine		Diesel Engine
		Natural Gas	Prod. Gas	Diesel
VOC	g/MM BTU of fuel	41.120	41.120	83.407
CO	g/MM BTU of fuel	342.445	342.445	362.100
NOx	g/MM BTU of fuel	1200.000	1200.000	635.370
PM10	g/MM BTU of fuel	5.530	5.530	35.298
PM2.5	g/MM BTU of fuel	5.530	5.530	35.298
SOx	g/MM BTU of fuel	0.603	0.603	8.038
CH_4	g/MM BTU of fuel	368.940	368.940	7.526
N_2O	g/MM BTU of fuel	1.500	1.500	2.000
CO_2	g/MM BTU of fuel	56,551	61,442	77,349
C as CO_2	g/MM BTU of fuel	58,242.4	63,134.0	78,221.4

We have assumed that emission factors for using produced gas in a reciprocating engine are the same as for natural gas except for C as CO_2, which is dependent on the gas composition, which in turn depends on the composition of the produced gas that is produced and whether or not natural gas supplements this gas for power generation. The emissions that affect GHG are CH_4, N_2O, and CO_2, which are converted to their GWP expressed as CO_2 equivalents using weighting factors from IPCC (shown in the following table). Thus, N_2O has a GWP potential 298 times that of CO_2; CH_4 has a GWP potential 25 times that of CO_2.

Table 3-3.
IPCC Emission Factors

GREET New IPCC Factors	CO_2 Equivalents
Carbon dioxide (CO_2)	1
Methane (CH_4)*	25
Nitrous oxide (N_2O)	298

* The methane GWP includes the direct and indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

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Heating Value

The heating value of crude oils and other hydrocarbon streams are determined using the API methodology for determining lower and higher heating values for hydrocarbons (API) Heating values of pure component C1-C4s are also from this reference. Lower heating values (LHV) are used, which assumes that the latent heat of vaporization of water in the fuel and the reaction products is not recovered. LHV is useful when comparing fuels where condensation of the combustion products is impractical or where heats at temperatures below 150˚C cannot be put to use.

Major Parameters Affecting Energy and Emissions during Crude Production

The following parameters have the most significant impact on GHG emissions from crude production:

- Reservoir properties
  - Depth
  - Pressure
  - Temperature
- Crude properties
  - Density (API)
  - Viscosity
  - Sulfur (affects heating value)
- Water to oil ratio
- Disposition of water
  - Disposal
  - Reinjection (includes produced water and imported water)
  - Clean up (includes cleanup of produced and imported water)
- Gas to oil ratio
- Gas composition—affects heating value and the CH_4 and CO_2 released during combustion, flaring and venting.
- Disposition of gas

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- Flaring
- Venting
- Fugitive emissions from equipment
- Sales
- Reinjection (includes produced gas and imported gas, including N_2, natural gas or CO_2)
- Clean up

Input to Crude Production Model

Input to the crude production model is shown in Table 3-4. The values shown are for a generic crude oil produced from a generic reservoir.

- The crude is characterized by its API and its heating value, which is calculated from its API gravity and sulfur content using the API method in Appendix B. Although in many applications fluid viscosity affects pumping energy, it is assumed that the flow rate and pipe roughness are such that the Fanning friction factor can be used to estimate pumping energy needed; viscosity is not part of calculations using Fanning friction factors. (Crane)
- Reservoir conditions include pressure, temperature, and depth.
- Production characteristics include the gas/oil and water/oil ratios and whether gas lift is used or if diluent is used to reduce the gravity of the oil. Diluent is generally kerosene that is pumped into the reservoir, blended with the crude, separated in the crude stabilizer and returned to the reservoir. The criterion for using diluent is when the crude API is less than 25. Gas lift was not used in this analysis.

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Table 3-4.
Input to Crude Production Model

Crude Description		
Crude Name		Generic
API		30.0
Sulfur	wt%	2.0
Heating value		LHV
Crude Heating Value	GJ/Bbl	5.82
Reservoir Characteristics		
Reservoir Pressure	psi	1,500
Reservoir Temperature	°F	200
Reservoir Depth	ft	5,000
Production Characteristics		
Gas/Oil Ratio	scf/bbl	1,000
Water/Oil Ratio	bbl/bbl	10.0
Gas Lift		No
Gas Lift Rate	SCFB	0.0
Diluent Lift - Use if API below:		25.0
Produced Gas Composition (mol%)		
Source for Gas Composition		Default
Input Gas Compositon		
H2S	mol%	1.0%
CH_4	mol%	75.0%
C_2H_6	mol%	14.1%
C_3H_8	mol%	4.7%
CO_2	mol%	5.0%
H20	mol%	0.3%
Gas Heating Value - LHV	BTU/SCF	1,018
Gas Heating Value - LHV w/o CO2	BTU/SCF	1,086
Venting of Produced Gas		
Vent Loss	%	0.5%
Fugitive Loss	%	0.5%
Reinjection of Gas and Water		
Gas Reinjection: % of Gas After Vent/Fugitive	%	50.0%
CO2 Separaton		Yes
CO2 Reinjection: %	%	100.0%
Water Reinjection: % of Produced Water	%	100.0%
Treatment of Reinjected Water		Yes
Treatment of Discharged Water		Yes
Disposal of Non-Reinjected Gas		
Amount of Non-Reinjected Gas	scf/bbl	500.0
Proportion of Gas to Flare	%	1.0%
Proportion of CO2 to Flare/Vent	%	50.0%
Flaring of Produced Gas		
% Combusted	%	99%
% Non-Combusted	%	1%
Fuel for Drivers and Heaters		
Downhole Pump Driver		Natural Gas
Water Reinjection Pump Driver		Natural Gas
Compressor Driver		Natural Gas
Fired Heaters		Natural Gas
Water Treatment		Natural Gas
Amine Treater - Fired Heaters		Natural Gas
Amine Treater - Drivers for Motors		Natural Gas

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- Produced gas composition—Produced gas consists of a mixture of C4- hydrocarbon components with H_2S and CO_2, which are generally less than a few percent. This gas, after separation of CO_2 and H_2S, is used in onsite power generation. The LHV of the gas is calculated from its composition.
- Venting and fugitive loss of produced gas occurs from the well casing, pump seals, valve packing and deliberate venting of gas. Venting and fugitive losses are generally less than a percent of the produced gas but are still significant because of the global warming potential of CH_4.
- Reinjection of gas and water—In many reservoirs, produced water and produced gas are reinjected. In other reservoirs, CO_2 is removed from the produced gas and reinjected.
- Fuel for Drivers and Heaters—Electricity powers the pumps, compressors, heaters in the stabilizer, deaerator, dehydration unit, H_2S and CO_2 removal units. This electricity can be supplied from the grid or from fuel generated onsite using produced gas or imported fuel. Because of concerns about the safety of fired heaters at an oil production site and because of manpower limitations, many sites use electric heaters instead of fired heaters on units that operate separation units: the crude stabilizer, product strippers, dehydrator, amine absorbers, *etc*. The crude production model assumes that associated gas produced during oil production drives the reciprocating engines that drive the electric generators. Natural gas is brought in as needed to supplement the associated gas. In the model, diesel fuel is an alternative fuel for power generation, or electricity can be supplied from the grid.

Assumptions used in the model are shown in Table 3-5.

Results from producing the Generic crude using the conditions in Table 3-4 are given in Table 3-6. Results are shown as energy (MJ of energy/MJ of crude) and GHG emissions (g CO_2e/MJ of crude), and are rolled up into the general categories shown on the table's right-hand side.

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Table 3-5A.
Crude Model Assumptions

Gas Composition (mol%)			
CAPP, April 2003, Page 16	Default (CAPP)		
CH_4	80.0%		
C_2H_6	15.0%		
C_3H_8	5.0%		
CO2	0.0%		
Reciprocating Compressors			
BHP/stage = 3.03 Z_{avg} $(Q_g T_s/E)(k/k-1)(P_s/T_s)[(P_d/P_s)^{(k-1/k)}-1]$			Source: GPSA Chapter 13, Page 10
Gas Re-injection			
T_s suction temperature	656.7	°R	Ts: suction temperature
Z_{avg} $(Z_s+Z_d)/2$	0.95		Zavg: (Zs+Zd)/2
E overall efficiency	0.85		E: overall efficiency
K ratio of specific heats, C_p/C_v	1.36		K: ratio of specific heats, Cp/Cv
P_s suction pressure	125	psia	Ps: suction pressure
P_d discharge pressure	3,400	psia	Pd: discharge pressure
P_L standard pressure	14.7	psia	PL: standard pressure
T_L standard temperature	520	°R	TL: standard temperature
Pumps			
BHP = gpm (differential pressure) / 1714 (efficiency)		Source: GPSA Chapter 12, Page 4	
Pump efficiency	0.65		
Convert BHP/gpm-psi	1714		
Water Re-injection Pump			
Water Injection Ratio	2	bbl/bbl	
Discharge Pressure	3,400	psia	
Vaporization	5.0%		
Downhole Pump			
Flow	58	gpm	
Differential Pressure	20000	psi	
Gas Lift			
Base Lift	1600	SCFB	
Base Depth for Gas Lift	8850	ft	
Diluent			
Diluent API	35.0		
Diluent/Oil Ratio	10%		
Diluent Lift - Use if API below:	35.0		
Reboiler (Crude Stabilization) & Fired Heater			
T_1	200	°F	
T_2	400	°F	
Heat of Vaporization	135	Btu/lb°F	Based on Wassan crude analysis
% Vaporization	10%	%	
% Vaporization if Diluent is used	25%	%	
Flow rate	590,396	lb/day	
Cp	0.44	Btu/lb°F	Armstrong Steam and Condensate Group, 816 Maple St., P.O. Box 408, Three Rivers, MI 49093
Diesel Powered Pumps and Compressors			
Diesel driver efficiency	75%		
Diesel Fuel consumption	0.19	I-BHP-hr	Source: Caterpillar and Cummins engine
Diesel fuel gravity	3,167	grams/gal	The Code of Federal Regulations (40 CFR 600.113) provides values for carbon content per gallon of gasoline and diesel fuel which EPA uses in calculating the fuel economy of vehicles:
Diesel fuel energy content	128,450	BTU/gal	The Code of Federal Regulations (40 CFR 600.113) provides values for carbon content per gallon of gasoline and diesel fuel which EPA uses in calculating the fuel economy of vehicles:
Electric Powered Pumps and Compressors			
Electric Motor Efficiency	92%		
Natural Gasl Powered Pumps and Compressors			
Natural Gas driver efficiency	75%		
Natural Gas consumption	7500	BTU/BHP-hr	Source: Caterpillar
Natural Gas energy content	909	BTU/SCF	Heating Values from API Technical Data Book 7th Edition - Chapter 14 Combustion (2005)
Water Properties			
Gravity of water	8.35	lb/gal	
Heat of vaporization of 1 lb of water at 15% vaporization	135	BTU/lb of water	
Pipe Friction			
Delta P = 0.000216 x (f x L x density x Q^2) / d^5			Source: Crane Handbook, Page 3-2, Darcy's Formula (Equation 3-5)
Delta P		psi	
	0.000216	ft^2 in^3 min^2 / gal^2	Note: High friction factor from Moody was used, therefore impact of viscosity on Reynolds Number negligible since flow is in turbulent region.
Friction Factor (f)	0.1		Changed 01-28-DEO
Reservoir Depth (L)	10,300	ft	
Density (SG) of pumped Liquid	59.1	lb/ft^3	Based on rate and properties of water and oil pumped from the reservoir
Flow (Q)		gpm	
Pipe Diameter (d)	3	in	

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Table 3-5B.
Crude Model Assumptions

Energy for Water Treatment			
15000	kwh/Acre-Ft		RO treatment
0.39	kwh/bbl		Reinjected water; - Reduce to 20% of RO
0.08	kwh/bbl		Water Discharge
Glycol Dehydrator			
H20 per mol of Glycol	0.6	mol frac	
Glycol Concentration in water	0.3	wt frac	
Glycol molecular weight	61.08	mol wt	
Delta water loading between rich and lean stream	0.2	%	
Solution density	1.003		
Lean glycol Pump Delta P	135	psi	
Lean glycol Pump Efficiency	0.8		
Latent Heat of Water	900	Btu/lb	
Molecular Weight Water	18.02	lb/lbmol	
Reflux Pump Delta P	75	psi	
Reflux Pump Efficiency	0.65		
Delta loading	0.2	wt%	
Adjust Glycol Circulation by Fresh/lean Glycol Soln	1.5		
Steam Rate	1	lb/gal of soln	
Steam Heat	1100	BTU/lb	
Air Cooler			
Duty from Hudson Software (Design Value assuming 100°F air	12.6	hp/1 MM SCFD of H20 Removed	
Annual Operation, % of Design	40%		
Amine Absorber			
CO_2 per mol of MEA	0.6	mol	
MEA Concentration in water	0.3	wt%	
MEA molecular weight	61.08	mol wt	
Delta acid gas loading between rich and lean stream	0.2	%	
Solution density	1.003		
Lean Amine Pump Delta P	135	psi	
Lean Amine Pump Efficiency	0.8		
Latent Heat of Water	900	Btu/lb	
Molecular Weight Water	18.02	lb/lbmol	
Reflux Pump Delta P	75	psi	
Reflux Pump Efficiency	0.65		
Delta loading	0.2	wt%	
Adjust Amine Circulation by Fresh/lean MEA Soln	1.5		
Steam Rate	1	lb/gal of soln	
Steam Heat	1100	BTU/lb	
Air Cooler			
Duty from Hudson Software (Design Value assuming 100°F air	12.6	hp/1 MM SCFD of CO2 Removed	
Annual Operation, % of Design	40%		
Additional Energy for Miscelaneious			
Miscelaneous additional energy	10%	of Energy used	

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Table 3-6.
Crude Model Output—Generic Crude

Energy Intensity	MJ/MJ of Crude
Downhole Pump	0.0186
Water Re-injection Pump	0.0216
Diluent Pump	-
Gas Lift	-
Gas Re-injection	0.0056
Crude Stabilization Reboiler @ 10% vaporization	0.0167
Water Deaeration	0.0127
Heater in Glycol Treater	0.0003
Pumps in Glycol Treater	0.0000
Heater in Amine Treater	0.0056
Pumps in Amine Treater	0.0001
Reinjected Water	0.0094
Water Discharge	-
Vented Produced Gas	0.0009
Fugitive Produced Gas	0.0009
Flared Gas	0.0009
CO2 Venting	-
Misc Energy	0.0090

Lifting	0.0186
Water Reinjection	0.0343
Gas Reinjection	0.0056
Water Treatment	0.0094
Gas Treatment	0.0226
Venting	0.0018
Flaring	0.0009
Misc Energy	0.0090
Total	0.1023
Check	0.1023

Total CO2e	g CO2e/MJ of Crude
Downhole Pump	1.25
Water Re-injection Pump	1.46
Diluent Pump	-
Gas Lift	-
Gas Re-injection	0.38
Crude Stabilization Reboiler @ 10% vaporization	1.12
Water Deaeration	0.85
Heater in Glycol Treater	0.02
Pumps in Glycol Treater	0.00
Heater in Amine Treater	0.38
Pumps in Amine Treater	0.01
Reinjected Water	0.63
Water Discharge	-
Vented Produced Gas	0.31
Fugitive Produced Gas	0.31
Flared Gas	0.06
CO2 Venting	-
Misc Energy	0.57
Total	7.35

Lifting	1.25
Water Reinjection	2.31
Gas Reinjection	0.38
Water Treatment	0.63
Gas Treatment	1.52
Venting	0.62
Flaring	0.06
Misc Energy	0.57
Total	7.35
Check	7.35

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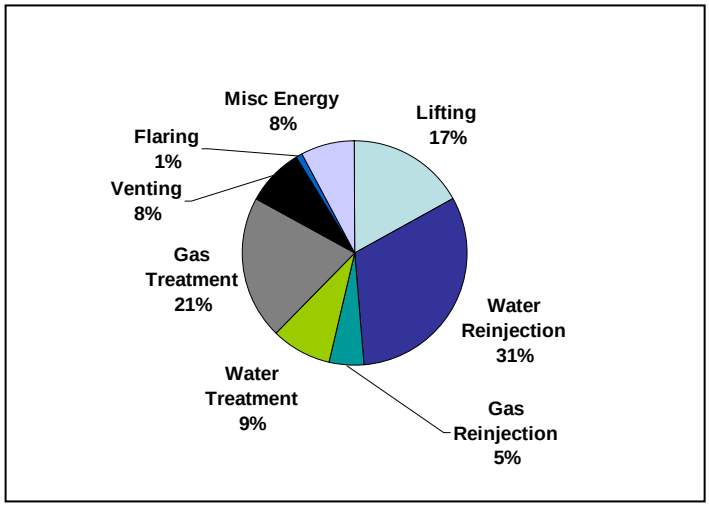
Magnitude of Energy in Production for Generic Crude from Generic Reservoir

This generic crude is at 30 API. The generic reservoir is 5,000 ft deep. Produced gas is at 1000 SCFB gas to oil ratio and water is produced at 10:1 water to oil ratio (bblw/bblo). All the remaining gas after onsite power generation is reinjected. Energy with water reinjection is shown. The energy required for production is around 10% of the energy in the crude. GHG emissions from production are 7.4 g CO_2e/MJ of crude. The breakdown of energy for production of this generic crude from the generic reservoir is shown in the following figure.

Figure 3-2.
GHG Emission Breakdown—Generic Crude from Generic Reservoir



The next question is how does the energy required for crude production change under different conditions? The following figure shows the results from exercising the model over a range of parameters one at a time for crude production at 3 reservoir depths: 5,000 ft, 10,000 ft, and 20,000 ft over the following range of parameters. The base parameters are for the generic crude discussed above.

- Water to oil: 0 to 25 WOR
- Gas to oil: 0 to 5,000 SCFB
- Reservoir pressure: 100 to 10,000 psi
- Venting of produced gas: 0 to 10% of produced gas
- Flaring of produced gas: 0 to 100% of net gas remaining after gas for electric power taken out

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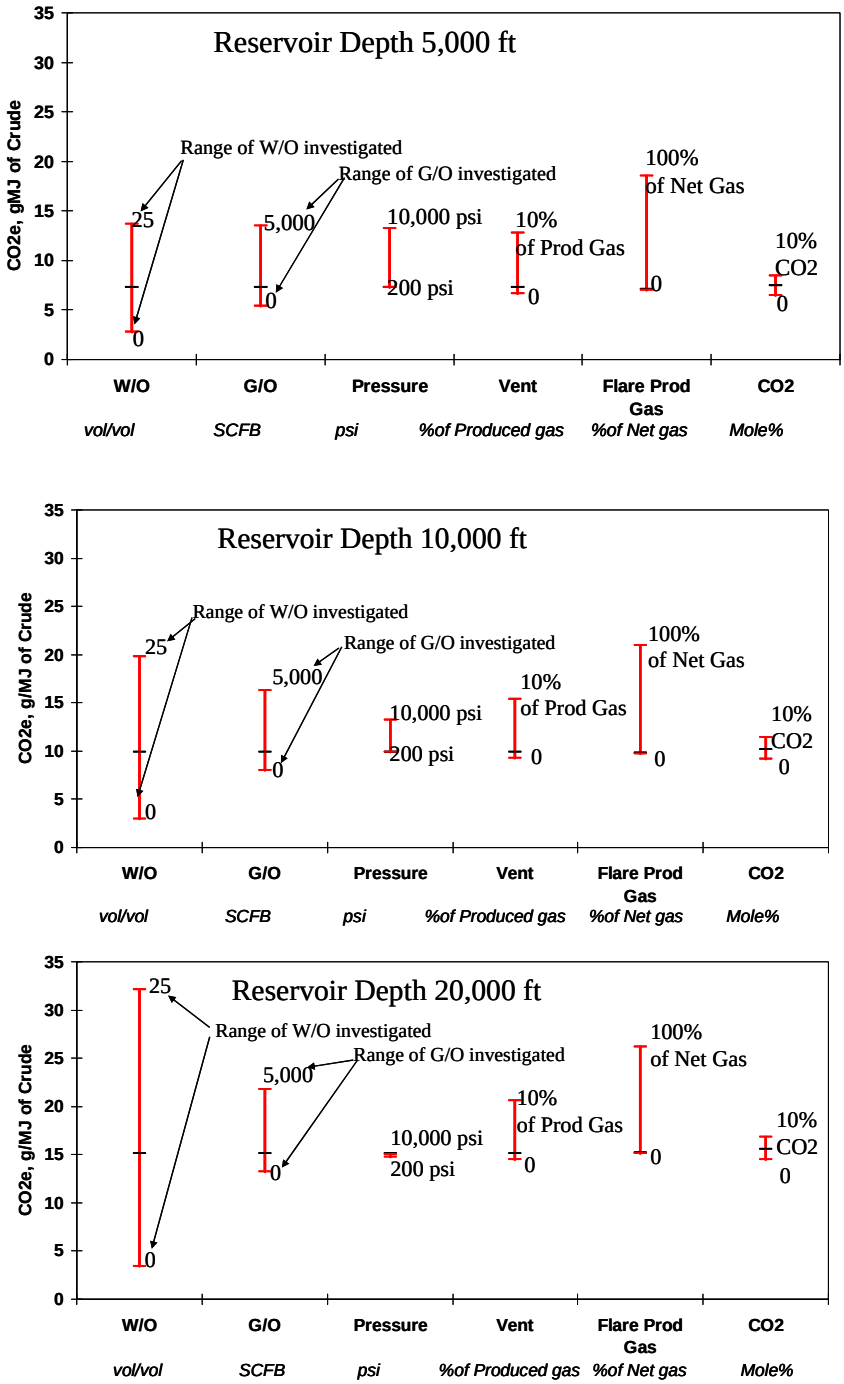
- CO_2: 0 to 10% in produced gas with venting of 100% of CO_2

Figure 3-3.
Impact of Production Parameters on Energy and GHG Emissions at Different Reservoir Depths for Production of Generic Crude



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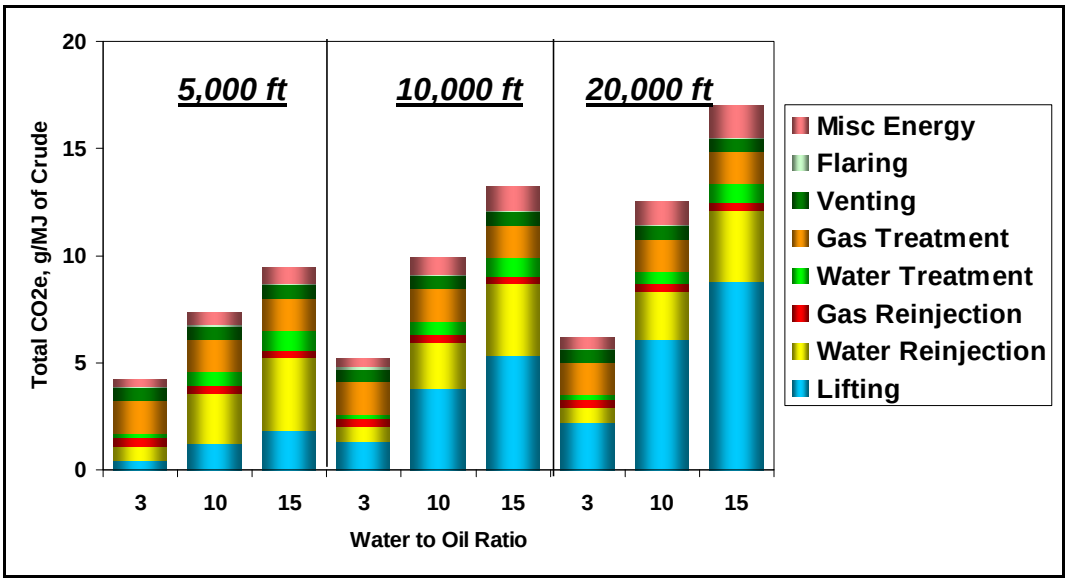
Results show that water to oil is a very significant parameter, and its significance increases with reservoir depth because the energy to lift the mixture of oil and water is determined by the energy to overcome gravity. The next most significant parameter is the gas to oil ratio. Flaring and venting of gas are also significant, as is venting of CO_2 from produced gas.

Figure 3-4 shows the GHG emission breakdown for producing crude at three water to oil ratios—3, 10 and 15—at three reservoir depths—5,000 ft, 10,000 ft and 20,000 ft. Lifting energy increases with WOR and reservoir depth.

Figure 3-4.
Impact of Reservoir Depth and Water to Oil Ratio on GHG Emissions from Generic Crude Production



Range of Reservoir and Crude Production Parameters

The above discussion focused on the impact of reservoir and production parameters in the production model for producing the generic crude. Now we will look at actual ranges for these parameters.

- Reservoir depth can range from a thousand feet or less to over 20,000 ft (Pennwell).
- Reservoir pressure can range from a few hundred pounds to over 15,000 psi in few locations. (Irani)
- Water to oil ratio in the US is 10:1 on average (NETL). In Canada, this ratio is 11:1 and worldwide it is around 3:1 (Bailey et al). For many older fields the WOR can be greater

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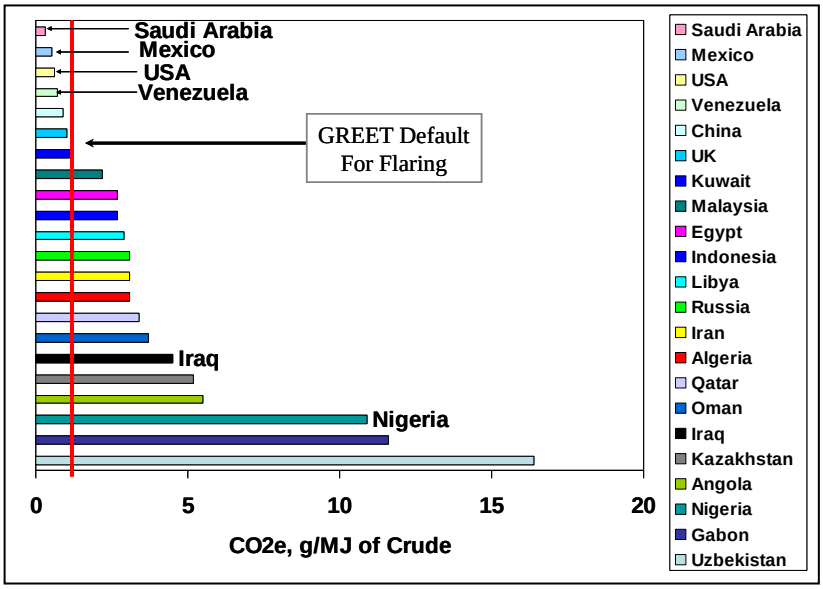
than 20:1 and in some marginal fields WOR of 100:1 has been reported (Veil et al., Seright et al, Sydansk) and increases as water injection is implemented. Produced water often contains oil and salt and must be treated before disposal. Any water that is reinjected into the reservoir must be filtered and deaerated. More water produced means more energy to clean it up.

- Gas to oil ratio can range from a less than 100 standard cubic feet per barrel of crude to well over 10,000 SCFB in a few reservoirs (Cubitt et al).
- Gas composition can vary from nearly all methane to a mixture of methane plus C2-C4s. Some reservoirs contain high concentrations of CO_2. One reservoir off the coast of Norway contains 10% CO_2 (Schlumberger). A production site in Argentina reported CO_2 content in the associated gas as high as 75 percent (Blann et al).
- Flaring of gas is a significant problem in some areas of the world. Results from a study sponsored by the World Bank shown in the following figure are based on analysis of satellite images by the US National Oceanic and Atmospheric Administration (NOAA) for the period ending in 2006 (World Bank). Nigeria and Iraq flare significant amounts of gas. The US and Mexico flare much less. Saudi Arabia flares very little gas. Figure 3-5 graphically represents the results from the World Bank study in terms of GHG emissions per MJ of crude. For comparison, the default value from gas flaring used in GREET is also shown.

Figure 3-5.
Venting of Associated Gas in Hydrocarbon Production



World Bank 2007

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- Flaring of gas, either as a means of disposal or as a safety measure to relieve well pressure, is the most significant source of air emissions from oil and gas installations. Even if continuous flaring ended, occasional burning of small amounts of gas will still be necessary for safety reasons, such as releasing excess pressure.
- Vented gas is also a significant source of GHG emissions. Methane venting occurs because of a number of factors. Gas produced with oil production leaks around casings. The extent of such leaks is a function of the amount of gas that is produced with the oil as well as the type of oil production equipment. Associated gas may also be vented rather than flared, but this practice is not safe. Examining the operational practices of oil fields in this study would provide more insight into venting. However, obtaining access to project specific data overseas would be challenging.
- Vented associated gas emissions are also reported in many parts of the world, including California and Canada. In many instances the emissions from overall GHG reporting are aggregated in a way that makes it difficult to either determine the specific source of emissions or to relate the emissions directly to throughput because projects are aggregated. More work could be done to review individual GHG inventory reports and investigate the details with the project operators.

Unconventional Crude Oil and Bitumen Production Methods

A variety of oil recovery operations involve steam injection or thermally processing the oil to facilitate its recovery (Green and Willhite). The processes that involve thermal oil recovery that are examined here include:

- Cyclic steam injection
    - California thermally enhanced oil recovery (TEOR)
    - Canadian oil sands
- Steam Assisted Gravity Drainage (SAGD) steam injection—Canadian oil sands
- Steam assist—Venezuelan heavy crude
- Surface mined bitumen with steam separation—Canadian oil sands

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Thermal Oil Energy Calculations

Thermal enhanced oil recovery (TEOR) results in additional energy use and greenhouse gas (GHG) emissions compared to conventional oil recovery. This is due to the injection of steam into the oil reservoir as part of the TEOR process. Understanding the emissions associated with thermal oil production requires an estimate of both the direct emissions associated with the combustion of fuel for steam generation as well as the indirect impacts of exported electric power from cogeneration.

While both the emissions and power generation from Canadian oil sands as well as California oil production operations are well documented, disaggregating the power exported from a range of projects is difficult. The difficulty often lies in uncertainty over the use of all of the steam and electric power. Cogenerated power and steam can be shared among projects, so assigning a reported emissions value to oil throughput is not always straightforward.

Energy inputs and emissions for thermal oil are based on a few key parameters that are tied to oil field operation. This approach is consistent with the process-based analysis applied to other oil production options in this report. A key parameter is the efficiency of steam generation for TEOR. The efficiency of generation differs depending on the technology used to generate the steam. The steam requirements for the thermal oil production options are shown in Table 5-7.

Table 3-7.
Steam Requirements for Thermal Oil Production

Reservoir Type	API Gravity	SOR	Comment
SAGD Bitumen	10	3	Dry steam basis
CA Thermal	<18	5	Wet steam basis
Bachaquero	12	0.5-1	Dry steam basis

Steam-Oil ratio

The steam-oil ratio (SOR) is a metric used to define inputs for thermal oil recovery. The SOR is the steam volume (reported as liquid water) required to induce production of a barrel of incremental oil.[1] The SOR varies with field character, the TEOR method applied (*e.g.,* steamflood vs. cyclic steam stimulation), and the maturity of the TEOR operation (the SOR increases over time as the field becomes depleted). The SORs for all California fields undergoing TEOR are presented below in Table 3-8 (DOGGR 2007). Using the columns from Table 3-8, the SOR is calculated by dividing total steam injected (bbl H_2O) by the incremental oil

[1] Incremental oil is oil that would not have been produced without the application of TEOR. The exact determination of incremental oil output depends on models that project what would have been produced without the application of TEOR.

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production (bbl oil). The production-weighted average SOR for all California TEOR fields is 5.13 bbl steam/bbl oil.

Table 3-8.
Steam-to-Oil Ratio by Field in California

Field	Incremental oil (bbl)	Injection—cyclic steam stimulation (bbl H_2O)	Injection—steam flood (bbl H_2O)	Total steam injected (bbl H_2O)	SOR (unitless)
Arroyo Grande	552,000	189,968	3,282,163	3,472,131	6.29
Belridge, North	64,000	67,815	0	67,815	1.06
Belridge, South	13,840,000	4,196,450	65,691,374	69,887,824	5.05
Coalinga	4,692,000	1,638,313	26,997,118	28,635,431	6.10
Cymric	3,359,000	38,854,038	16,951,245	55,805,283	16.61
Jasmin	1,000	0	168,000	168,000	168.00
Kern Front	1,037,000	482,068	7,159,175	7,641,243	7.37
Kern River	30,000,000	16,373,664	76,073,254	92,446,918	3.08
Lost Hills	1,750,000	593,118	10,049,285	10,642,403	6.08
Lynch Canyon	64,000	96,767	0	96,767	1.51
McKittrick	1,755,000	1,088,581	7,053,251	8,141,832	4.64
Midway-Sunset	32,543,000	56,815,440	113,250,530	170,065,970	5.23
Mount Poso	3,000	0	254,695	254,695	84.90
Orcutt	16,000	106,216	0	106,216	6.64
Oxnard	50,000	133,981	0	133,981	2.68
Placerita	1,000,000	3,225,435	7,088,412	10,313,847	10.31
Poso Creek	101,000	2,720,747	602,798	3,323,545	32.91
Round Mountain	1,736,000	0	7,184,515	7,184,515	4.14
San Ardo	2,812,000	1,809,762	19,068,638	20,878,400	7.42
Total	**95,375,000**	**128,392,363**	**360,874,453**	**489,266,816**	**5.13**[2]

California thermal oil production differs significantly from thermal bitumen recovery operations in Canada.

Figure 3-6 shows a range of SOR values reported for several projects in Canada reported by EnCana at an investor conference. These values show a range from a high of 8 SOR for one project to a low of just over 2 SOR for a pilot project. On average, the SOR ratios for most SAGD projects in Canada are around 3. Depending on the reservoir conditions, the values can go over 5; however, SORs this high are exceptional. Newer production methods using down-hole pumps, better heat integration, and other methods are being put in place in Canada to reduce the steam to oil ratio to less than 3.

[2] This average SOR is a production-weighted average SOR.

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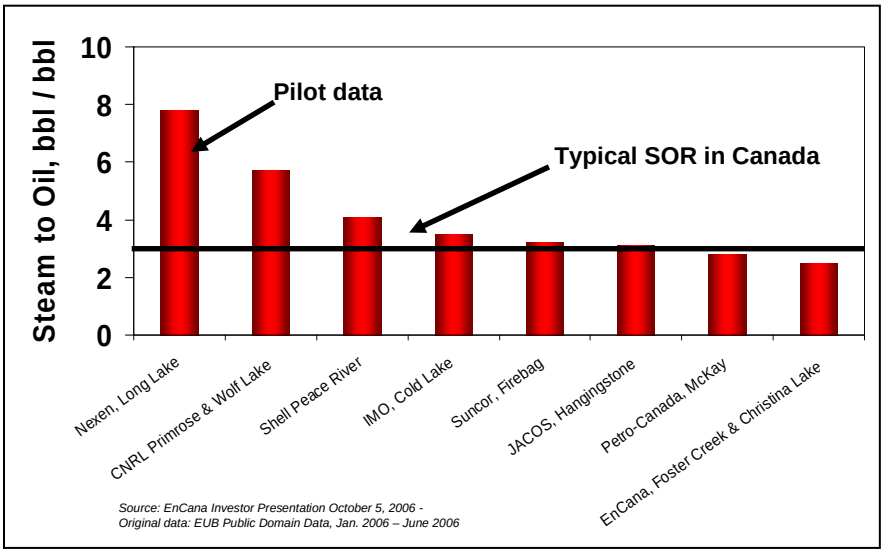
Figure 3-6.
Steam to Oil Ratio—Canadian Oil Sands Projects



EnCana

Energy for Steam Generation

The amount of energy contained in a given mass of steam above a reference state (the steam enthalpy H_{steam}) depends on the steam pressure and steam quality.[3] Steam quality is the fraction of the water that is in vapor form. Steam used in California's TEOR projects is generated at no more than 80% quality due to scaling that occurs within the generator when water with dissolved ions is converted to 100% steam (Hong). We calculated the energy content of steam mixtures of various qualities (Cengel and Boles) and compared these to values from the literature in the following table.

[3] We assume here that the steam is not superheated, i.e., not all water is vaporized and there is still water left in small liquid droplets.

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Table 3-9.
Energy Requirement for Steam Generation

Source	Energy Requirement (mmBtu/bbl steam)	Notes
Calculation	0.328	60% quality steam at 500 psia
Calculation	0.362	80% quality steam at 500 psia
Calculation	0.29 to 0.31	Calc for 1500 psi
Green and Willhite (1998)	0.35	Rule of thumb for energy content of TEOR steam.
Hong (1994)	0.303	p. 58, adjusted by author for different reference temperature.
Hong (1994)	0.316	p. 91, for maximum output from 50 MmBtu generator.

Steam Generation

In once-through steam generators (OTSGs), the water moves through the steam generator in a single pass. These generators produce steam with a maximum quality of about 80% (Hong 1994). These generators have a thermal efficiency (enthalpy received by water / lower heating value of the fuel) of 80-85% (Burger, Sourieau *et al*.).

Mining of Bitumen

Mining of bitumen is applicable for reservoirs where the depth of the oil is less than 100 m below the surface. Mining is typically done by first removing the overburden, which consists of 1 to 3 meters of muskeg, which sits on top of a layer of clay and barren sand. The underlying oil sands are in a band that is typically 40 to 60 meters thick which sits on top of a layer of limestone rock. The overburden is first removed and the underlying oil containing layer is then removed using surface mining methods. The oil and clay particles are then sent to the extraction plant where hot water at 50-80˚C is added to the ore; the formed slurry is transported using a hydrotransport line to a primary separation vessel where bitumen is recovered by flotation as bitumen froth.

The recovered bitumen froth consists of 60% bitumen, 30% water and 10% solids by weight, and must be cleaned to reject the contained solids and water to meet the requirement of downstream upgrading processes. Depending on the bitumen content in the ore, between 90 and 100% of the bitumen can be recovered using modern hot water extraction techniques. After oil extraction, the spent sand and other materials are then returned to the mine, which is eventually reclaimed.

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Energy for producing bitumen by mining include the diesel fuel for the trucks and shovels used in mining; electricity for the mechanical equipment used to move the ore and spent clay, and to run the separators; and natural gas to generate the steam used to generate the hot water used in separation and for solvent recovery. The energy for mining is typically about one half of the energy needed for a SAGD operation operating at a 3 SOR.

Electric Cogeneration

The other method of producing steam in California TEOR and Canadian cyclic and SAGD operations is as part of a cogeneration system. Cogeneration systems simultaneously produce steam and electric power. The electric power is used onsite for oil field operations and any excess is exported to the power grid. The steam generation efficiencies for cogeneration systems are lower than those of OTSGs because electricity is also being produced.

A variety of steam generation sources provide energy for TEOR facilities, including natural gas fired steam generators as well as natural gas and a few coal-fired cogeneration facilities. California statistics include data on production by oil field. Data are also available on steam consumption, fuel consumption, and power production capacity for each oil production project (DOGGR).

Electricity is also produced in cogeneration-based thermal projects in California and Canada. This electricity co-production receives a credit because any net power exported to the grid offsets power production elsewhere, lowering GHG emissions elsewhere. The amount of power co-produced varies by the design of the project. Some projects result in very high power production, while others mostly generate steam.

This electricity is generated with a power generation efficiency that we define as follows:

$$\eta_{elect} = \frac{\text{Electrical energy produced (MM BTU)}}{\text{Energy consumed by cogeneration system (MM BTU LHV)}}$$

Electric Consumption

Thermal oil recovery operations also consume electric power to operate pumps, oil water separators, and other equipments. Surface mining includes a wide range of electrical loads such as conveyors, crushers, and defrothing equipment.

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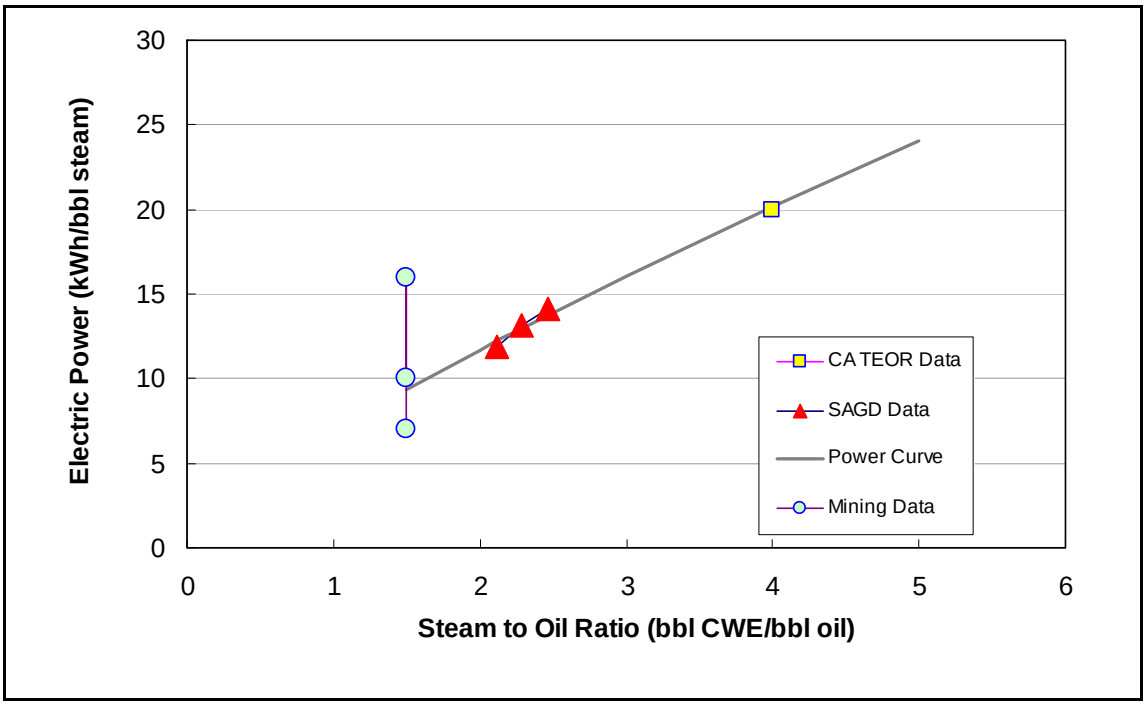
The analysis here combines the estimated electric power consumption to either determine the electrical requirements for thermal oil production or the next export of electric power. Power consumption for oil production depends on many factors and is quite variable. Figure 3-7 shows an estimate of the electric power requirements for different oil production technologies (Bergerson, EPRI, DOGGR, and Jacobs Engineering). The data are plotted against SOR.

Figure 3-7.
Utility Requirements for Bitumen and Heavy Oil Production



Thermal Oil Analysis

Assumptions for thermal oil are shown in the following table. Fuel requirements are calculated either for an incremental or full cogeneration scenario. With the incremental case, cogenerated electric power provides only the electric power needed for on-site requirements and cogenerated steam is used with steam from an OTSG to meet steam requirements. In the full cogeneration case, all of the steam is provided from cogeneration and excess power is exported to the grid. The full cogeneration case requires considerably more fuel but electric power exports reduce the overall GHG emissions. The incremental cogeneration cases use the least fuel on-site because most of the steam is generated with an OTSG and very little energy is required for power generation. The full cogeneration cases use more fuel on-site and results in greater direct emissions. However, these emissions are offset by the credit for cogenerated electric power.

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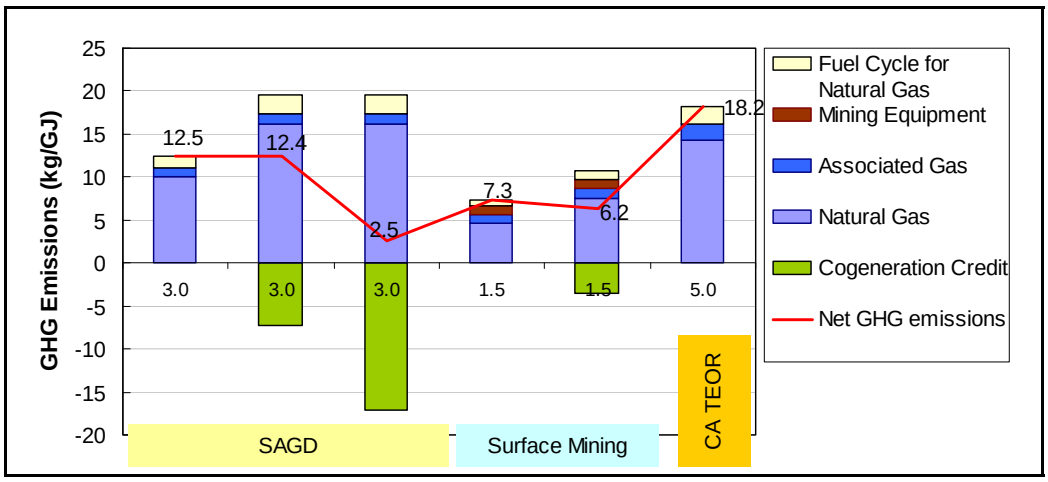
Table 3-10.
Energy Inputs for TEOR with Cogeneration

Scenario	Steam Assisted Gravity Drain (SAGD)					CA TEOR
Scenario number	OSSD.AB.2	OSSD.AB.5	OSSD.AB.6	OSM.AB.1	OSM.AB.3	O.CA.3.3
Location	Alberta	Alberta	Alberta	Alberta	Alberta	California
Export Power	none	NG CC	Alberta	none	NG CC	Cogen
Steam technology	incr.Cogen	Cogen	Cogen	incr.Cogen	Cogen	Cogen
Resource characteristics						
Steam oil ratio, bbl steam (CWE) / bbl oil	3.0	3.0	3.0	1.5	1.5	5.0
Dry steam basis	3.0	3.0	3.0	1.5	1.5	4.0
API gravity deg. API	10.0	10.0	10.0	10.0	10.0	13.4
Steam characteristics						
Steam net enthalpy (mmBtu/bbl of steam)	0.311	0.311	0.311	0.311	0.311	0.33
Efficiencies						
Power η (J_e /J fuel)	56.9%	21.0%	21.0%	56.9%	21.0%	21.0%
Incremental power η (J_e /J waste heat)	56.9%	51.0%	51.0%	56.9%	51.0%	51.0%
Steam generation η (J steam/J fuel)	85.0%	50.0%	50.0%	85.0%	50.0%	50.0%
Cogeneration η (J steam + e^- /J fuel)	N/A	71.0%	71.0%	N/A	71.0%	71.0%

Thermal oil inputs provide the basis for calculation using the GREET emission factors. Results are shown in the following figure.

Figure 3-8.
GHG Emissions from Thermal Oil Production



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The effect of electric power with two different GHG intensities is shown for the SAGD case. In the middle SAGD column, a credit for offsetting combined cycle natural gas power is applied to the export power. Here the net GHG emissions are the same as the incremental cogeneration case. When export power is substituted for grid power assuming an 80% coal fired mix, the net GHG emissions are much lower. The results for surface mining are proportional to those for SAGD except less thermal energy is used and the overall GHG emissions and cogen credit are lower. Results for California TEOR are higher than for SAGD primarily because of the higher effective SOR in California. An SOR of 5 is comparable to an SOR of 4 on a dry steam basis.

Please see Section 8 for a more comprehensive discussion of cogeneration and emissions credits for co-production of export power. Note that a cogenerated power export analysis was not carried out for California thermally produced crudes as part of the Study. Potential for export power co-product emissions credits also exists for these California crudes. It is recommended that this potential be considered as part of a future, more comprehensive evaluation regarding the impact of cogenerated power export.

Study Crudes

The conventional crudes that we have selected for our study are all well known and widely traded. Physically, they cover a range of crude properties: light sweet, light sour, heavy sour, and a heavy relatively low sulfur crude. Below, we briefly review the properties of these crudes and the reservoirs from which they are produced.

- Maya—Maya is a 22.1 API Mexican crude with 3.3 wt% sulfur that is produced from the Cantarell field offshore in the Bay of Campeche. For a 22 API crude, Maya has unusually poor qualities. It is over 35% vacuum residue and the VR is about 5 wt% sulfur and high in vanadium and nickel. As a result, Maya is usually processed in a refinery with a delayed coker. Because it is widely traded and its pricing is transparent, Maya is the “marker” heavy crude in the US Gulf Coast.

  Reservoir depth ranges 6400 to 12000 ft. (Pennwell)

  - Reservoir pressure is moderate at around 1600 psi (Hernandez, Kuo, Manceau, Alfredo)
  - Gas production is on the order of 90 vol/vol or 340 SCFB (Manceau)
  - As a result of declining crude oil production, Pemex built the world’s biggest air separation plant to supply 1.2 billion cubic feet per day of nitrogen to the Cantarell field in 2000. A 500 MW power plant was built to operate this plant (Kuo, Hernandez, Alfredo, MAN).

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- Mexican oil production typically averages 3 WOR (Izundu)

- Bachaquero—Bachaquero is a heavy Venezuelan crude. There are several Bachaquero blends sold in the market, including 14 and 17 API blends. For our work, we have selected the heaviest of the Bachaquero blends at 10.7 API. As compared to Maya, Bachaquero has less sulfur (2.8 wt%), but the VR is unusually high in metals, about 1000 ppm. As a result of this and the sulfur content, most Bachaquero is processed in a delayed coker refinery.
  - Reservoir depth ranges from 1,200 to 12,000 ft (Pennwell)
  - Reservoir pressure is low at around 500 psi (Guevara, McGee, Merle)
  - Gas production is around 90 SCFB (Guevara, McGee)
  - Water production is low < 0.3 bbl/bbl (McGee)
  - Steam injection at SOR ratios of 0.5-1 bbl/bbl are being used in some reservoirs (Pizzarelli, Mendoza)
- Kern River—Kern River is a 13.4 API, 1 wt% sulfur crude produced in the eastern San Joaquin Valley of California. Discovery of oil in Kern County dates from the late 19th century. Although the sulfur is low, Kern River is very hydrogen-deficient and is a low quality crude. For example, the vacuum gas oil from Kern River is about 14 API. For most crudes, this cut is 20 to 23 API. Kern River is best processed in a delayed coker configuration with considerable hydroprocessing to upgrade the gas oil and middle distillate fractions.
  - Production is by cyclic steam injection which puts this crude into the category of unconventional production
  - Gas production is low
  - Water production is a result of steam injection
  - Reservoir depth is around 900 ft (Gautier)
  - Reservoir pressure is around 35 psi (Gautier)
- Arab Medium—There are three widely traded Saudi Arabian crudes: Arab Light, Medium and Heavy. All are blends produced from the massive reservoirs in the Kingdom's Eastern Province. Arab Medium is a nominal 31.1 API, 2.6 wt% sulfur crude. The vacuum residue portion is 4.9 wt% sulfur. While the crude is run in blends to produce high sulfur fuel oil in some parts of the world, it is best suited for a refinery with a delayed coker.
  - Reservoir depth ranges from 4,800 to 6,900 ft (Pennwell)
  - Reservoir pressure is around 3,000 psi (Kokal)

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- Gas production is around 650 SCFB (Kokal)
- Water production is moderate at 2.3 bbl/bbl (Staniford, Simmons)
- Saudi Arabia has an extensive network supplying 4 MM BPD of seawater 50 miles through a 5-ft diameter pipe to their inland oil fields. The energy to supply this water results in around 0.12 g CO_2e/MJ of crude.

- Bonny Light—Bonny Light is a high quality (32.9 API, 0.16 wt% sulfur) Nigerian crude. It has very little (about 6 vol%) vacuum residue, with less than 0.5 wt% sulfur in the VR. It can easily be processed in a medium complexity (no coker) refinery to produce transportation fuels and some low sulfur fuel oil. Bonny is popular in Europe and in the US East Coast refineries.
  - Reservoir depth ranges from 5,000 to 14,000 ft (Pennwell)
  - Reservoir pressure is fairly high at around 4300 psi (Inikori)
  - Produced gas is around 840 SCFB (Aron, Inikori, Boni, Chugbo)
  - Significant quantities of produced gas is flared (World Bank)
  - Water production is less than 2 bbl/bbl (Boni)
- Kirkuk—At 36.6 API, Kirkuk is our lightest crude. However, it is high in sulfur: 1.97 wt% sulfur in the crude and over 5 wt% in the vacuum residue. Because there is a relatively low volume of VR, Kirkuk can be run in blends to produce high sulfur fuel oil. Kirkuk is an Iraqi crude.
  - Reservoir depth ranges from 2,000 to 10,000 ft (Pennwell)
  - Reservoir pressures are around 3,000 psi (Al-Naqib, APS Review)
  - Water injection has been used since the 1960s; saline water incursion has led to water breakthrough (Al-Naqib, APS Review)
  - Data on Kirkuk are out of date and incomplete
- Mars—Mars is a US domestic sour crude produced offshore in the Gulf of Mexico. The crude is 31.5 API, 1.8 wt% sulfur. Physically, Mars is very similar to Arab Medium in distillation and properties. Not surprisingly, our assessment of GHG per barrel for processing Mars is the same as our assessment for Arab Medium.
  - Reservoir depth for this deepwater production ranges from 10,000 to 19,000 ft
  - Reservoir pressure is around 5,500 psi (Weiland)
  - Water injection has been practiced from initial production (Weiland)
  - Water to oil is around 5.5 (Farid, Upstream Online, JPT)

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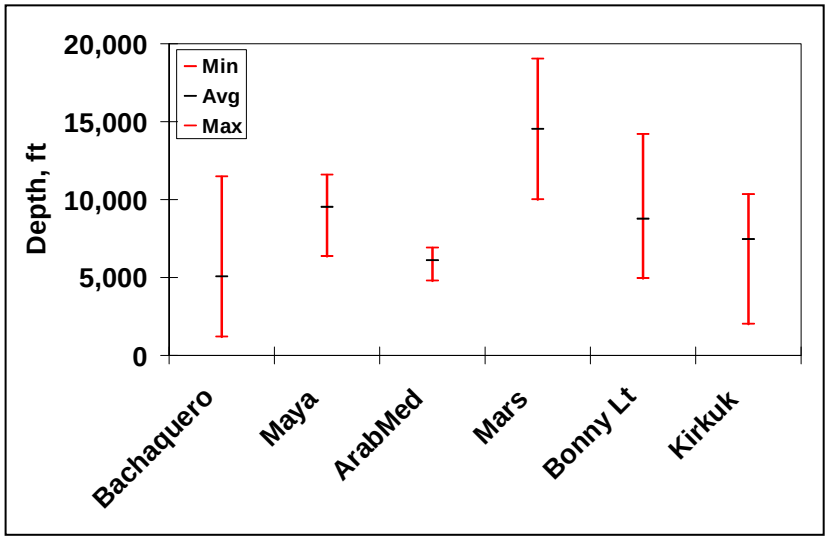
- Produced gas is over 1,000 SCFB (Weiland, Offshore-GOM)

GHG Emissions for Production of Study Crudes, Bitumen, and California TEOR

The depth of the reservoirs from which the study crudes are produced is shown in the following figure.

Figure 3-9.
Reservoir Depth—Study Crudes



Pennwell

A summary of the known reservoir parameters for the study crudes is shown in the following table.

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Table 3-11.
Summary of Reservoir and Production Parameters for Study Crudes

Petroleum Reservoir	Avg Depth,	Pressure,	Thermal Steam to Oil	Water to Oil	Produced Gas,	Flared Gas (Wrld Bnk Rpt)	Flared Gas (NOAA 2007)	N2 Injection
	ft	psi	bbl /bbl	bbl /bbl	scf / bbl	(m3 gas/bbl)	(m3 gas/bbl)	scf / bbl
Bachaquero	5,100	500	0.5	0.25	90	2.0	2.2	-
Maya	9,500	1,600	-	3	340	0.6	1.4	1,200
Arab Medium	6,100	3,000	-	2.3	650	0.8	0.9	-
Mars	14,500	5,500	-	5.5	1,040	0.6	0.6	-
Bonny Light	8,700	4,300	-	2	840	27.0	19.6	-
Kirkuk	7,500	3,000	-	2	600	11.0	9.1	-

GHG Emissions for Conventional Crudes

The energy and GHG emissions from producing each study crude were determined using the crude production model and parameters shown in this table. Due to a lack of information about the produced gas composition produced for each of the study crudes, the gas composition for each crude was assumed to be the same as for the generic crude described above. Again, due to lack of specific information, venting and fugitive emissions were assumed to be 1% of the produced gas for each of the study crudes. When there were other parameters that were not defined for a specific crude, the values for the generic crude described above were assumed. Flaring data is from the World Bank report.

For Bachaquero and Maya crudes there are two additional sources of energy use that are not evaluated in the crude production model. In the case of Bachaquero, the energy for injecting 0.5 bbl of steam per bbl of oil to increase production Bachaquero crude was determined using the methods described below for thermal recovery of crude oils. Steam assist adds about 1.9 g GHG/MJ of crude. For Maya, the energy to separate nitrogen from air and compress it to reservoir conditions is based on published information about the nitrogen production for use in the Cantarell field. The energy to compress 1,200 SCFB of nitrogen to the reservoir pressure is determined from the production model. Nitrogen production, compression and injection add around 1.3 g GHG/MJ of crude.

The estimated GHG emissions for production of each of the conventional crudes in the Study are shown in the following figure. The high and low values correspond to the maximum and minimum reservoir depth for each reservoir.

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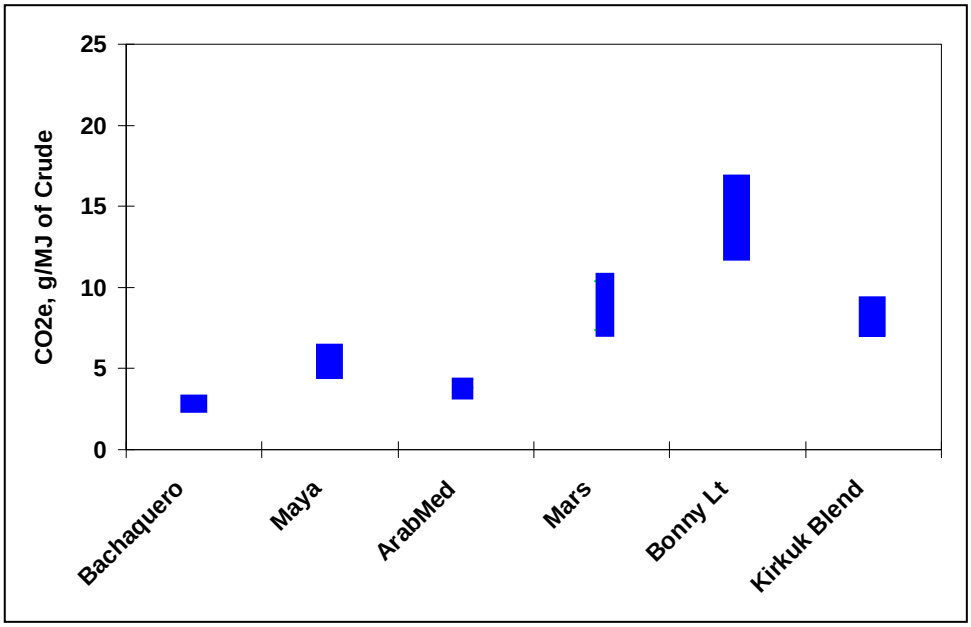
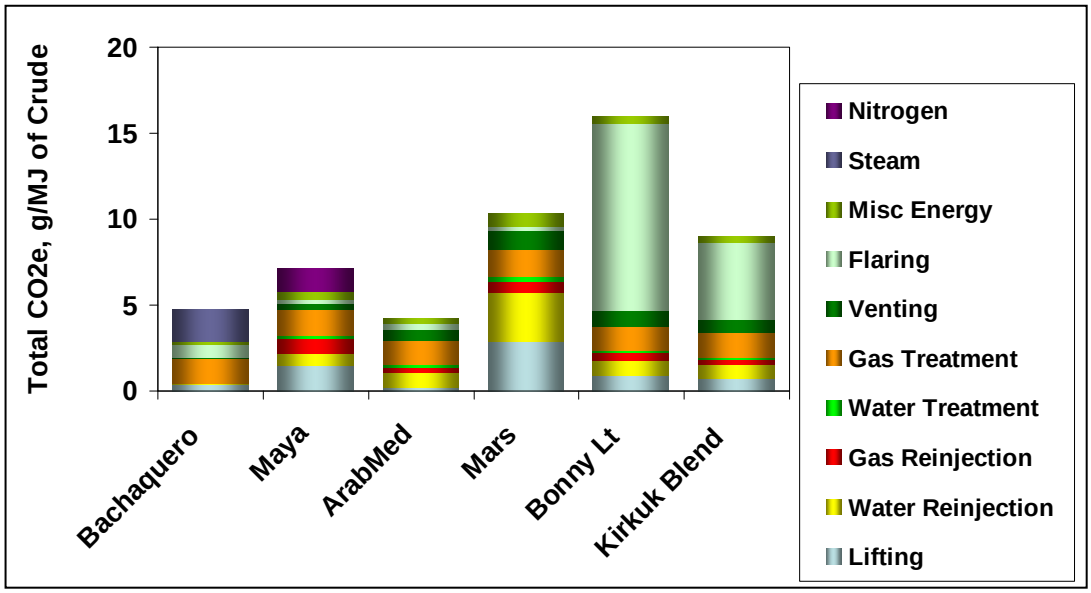
Figure 3-10.
GHG Emissions from Crude Production—Conventional Production



The breakdown of emissions is shown in the following figure for each of the study crudes. The impact of flaring on emissions for producing Bonny Light is significant. The impact of reservoir depth and water to oil ratio is significant on emissions from producing Mars crude, which is produced from a great depth.

Figure 3-11.
Sources of GHG Emissions for Crude Production



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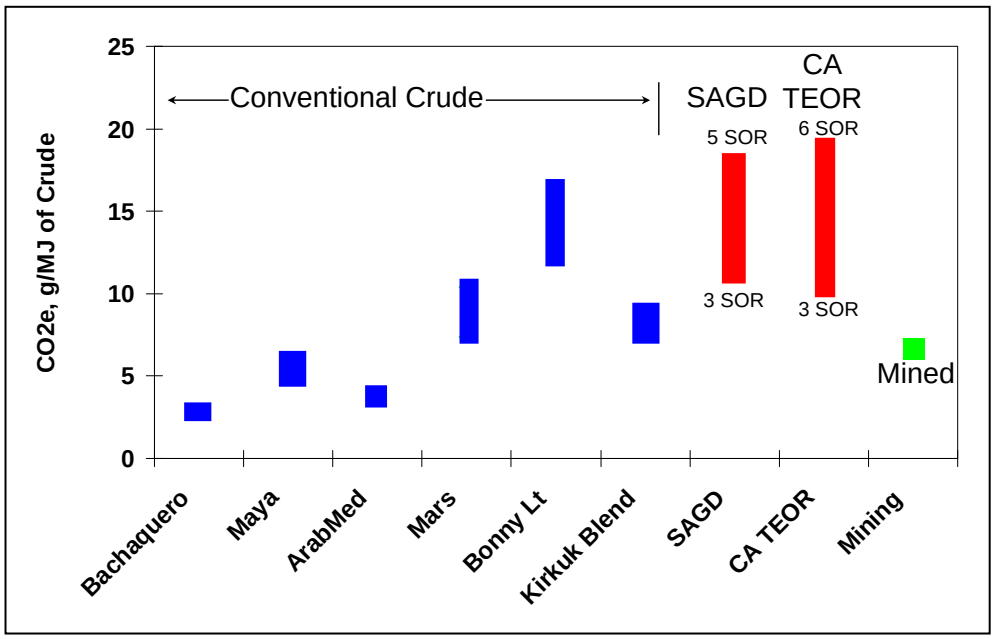
GHG Emissions for Bitumen and CA TEOR

Results in Figure 3-12 show GHG emissions from the production of the conventional crudes in the Study, for thermal production of bitumen in Canada, and for heavy crude from the Central Valley in California. Also shown in Figure 3-9 are the GHG emissions for producing bitumen by mining.

Figure 3-12.
GHG Emissions from Crude Production—Conventional and Unconventional Production



The conclusion from this analysis is that there is a wide range in GHG emissions from producing crudes and it is not sufficient to use an average to describe oil production. By including flaring, nitrogen injection, and reservoir depth, it can be seen that emissions from production of several of the conventional crudes overlaps with emissions for thermal production of crudes. Mining of bitumen has a GHG emission burden well below that of several of the conventional crudes in the study.

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Section 4.

Bitumen Upgrading

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Upgrader Flow Schemes

The processing steps in bitumen upgrading are designed to convert bitumen to synthetic crude oil (SCO) that will be processed to produce transportation fuels in a conventional refinery.

The two configurations evaluated in this study for bitumen upgrading differ in the primary upgrading technology: delayed coking vs. ebulating bed (Eb-Bed) hydrocracking. The other process units used in both configurations consist of a gas oil hydrotreating unit (GOHT), distillate hydrotreating unit (DHT) and naphtha hydrotreating unit (NHT). In addition, the upgrader requires a sulfur plant that converts H_2S to elemental sulfur, a gas plant for separating C4- components into fuel gas and C4s (C3s are produced as fuel gas), and a hydrogen plant that converts natural gas to hydrogen via steam methane reforming. In this analysis, coke from the coking-based upgrader is stored and not used as fuel. Unconverted bottoms material (UCO) from the Eb-Bed upgrader is blended to SCO. The yield of SCO is greater from the Eb-Bed based upgrader as a result of including the unconverted oil from the Eb-Bed unit in the SCO and adding more hydrogen than in the coking based upgrader. The feed rate to the upgraders was adjusted to produce 140 KBPD of SCO for downstream refining.

Table 4-1 shows the specifications typically used for SCO and those used in this study. The SCO specifications for the study were relaxed somewhat because unconverted material from the Eb-Bed hydrocracking unit is included in the SCO and because the downstream refining configurations considered in this study are capable of handling heavy material.

Table 4-1.
SCO Specifications

		Typical Specs	Alternative Specs for Study	
			Delayed Coker	Eb-Bed
API		> 29.3	>29	>22
Sulfur	wt%	<0.1	<0.5	<0.5
Composition				
C4-	vol%	< 3	< 3	< 3
Naphtha IBP-350°F+	vol%	15-30	15-30	>10
Distillate 350-650°F+			>30	>25
Gas Oil 650-1000°F+	vol%	25-36		
Resid 1000°F+	vol%	< 1		<15
Naphtha Properties				
Sulfur	ppm	<5		
Nitrogen	ppm	<1		
Distillate Properties				
Sulfur	ppm	< 250		
Cetane Number		40 min		
Gas Oil Properties				
Sulfur	ppm	<1000	< 7000	<1000
Nitrogen	ppm	<1000		

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The overall flow schemes for the two upgrading configurations are shown in the following two figures. A brief description of the process units follows.

Figure 4-1.
Coking-Based Upgrader

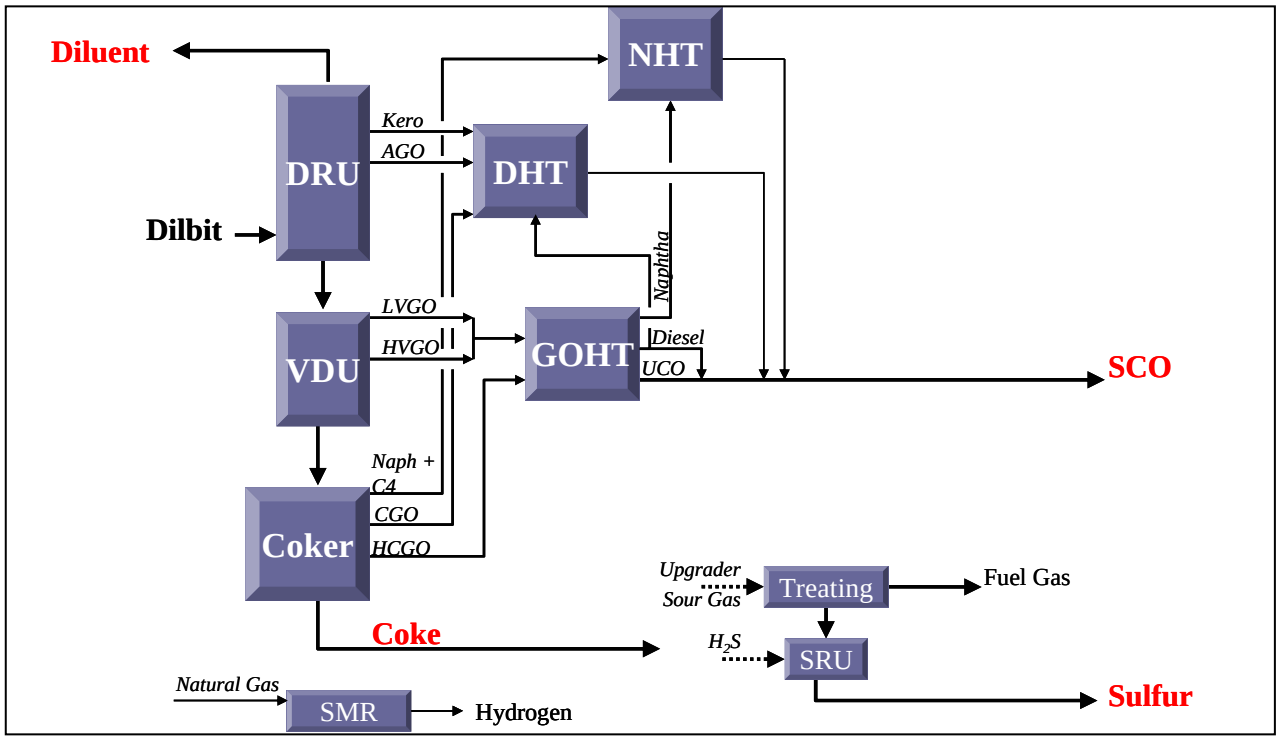

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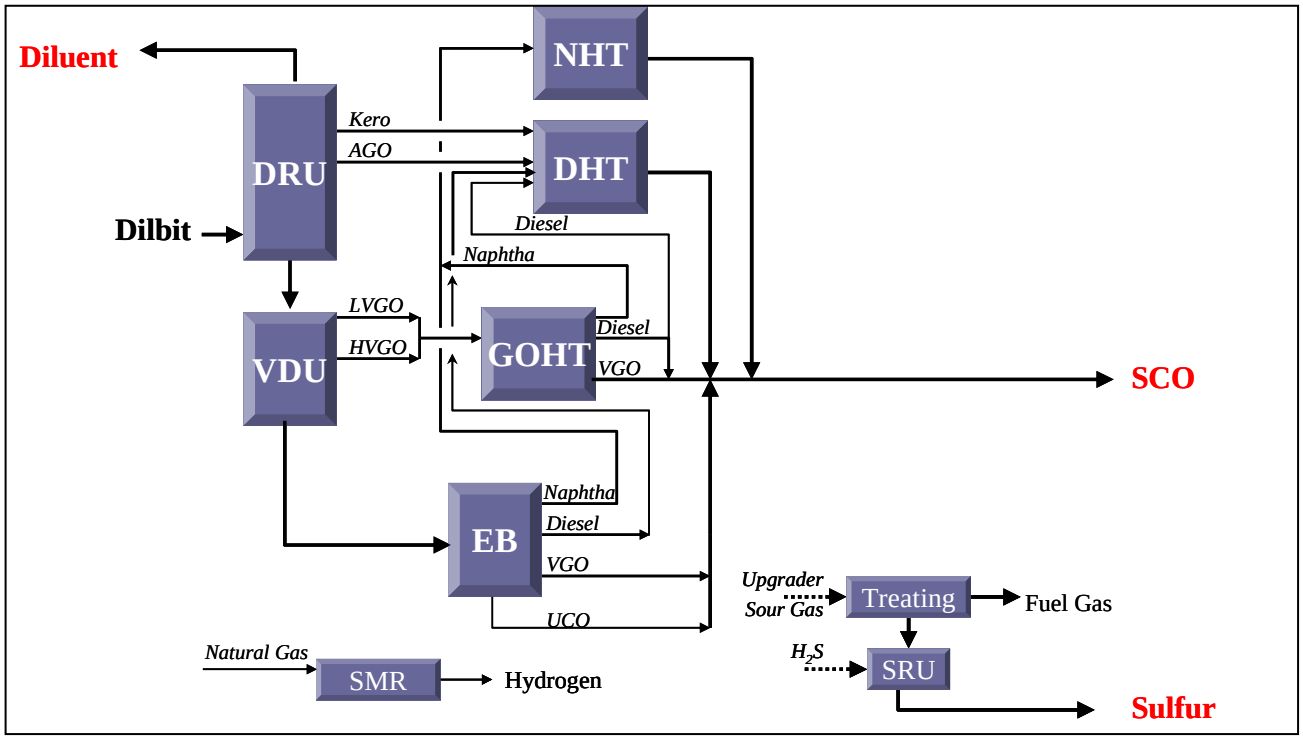
Figure 4-2.
Ebulating Bed-Based Upgrader



Process Description for Upgrading

- **DRU**—The distillate recovery unit (DRU) separates the naphtha diluent from the bitumen and fractionates the bitumen into distillate and heavy atmospheric resid, which is further fractionated in the vacuum distillation unit (VDU). The DRU is a single column with a one- or two-stage preflash. Atmospheric gas oil go to the DHT (Distillate Hydrotreating Unit). The DRU atmospheric residue bottoms (AR) is sent to the VDU for further gas oil recovery. The AGO cut point was set to generate a distillate stream that will produce a 650˚F (343˚C) end point in the diesel hydrotreater product stream.

- **VDU**—The vacuum distillation unit (VDU) produces vacuum resid, which is sent to a coking unit, and light and heavy vacuum gas oils, which are sent to the Gas Oil Hydrotreating Unit (GOHT). The DRU and VDU are typically heat integrated.

- **Delayed Coking Unit**—The coking unit converts vacuum resid from the VDU into lighter components, fuel gas, C3 and C4 olefins, naphtha, distillate, and gas oils. The delayed coker consists of several coke drums that feed a common fractionator. Fuel gas and C3s go to the Gas Plant. Naphtha and C4s from the coker are routed to the NHT where any olefins are saturated to ensure stability of the SCO. The light coker gas oil (LCGO) from the coker is low in cetane number and high in sulfur and requires processing in the

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distillate hydrotreater. The heavy coker gas oil (HCGO) is further processed in the GOHT to achieve the sulfur target. Coke from the delayed coker is stored in a landfill.

- **Ebulating Bed Hydrocracking Unit**—The Eb-Bed hydrocracking processes the vacuum resid from the VDU. It is configured with 2 trains consisting of 2 reactors in series, operating at approximately 2900 psig reactor inlet pressure. Naphtha is sent to the NHT, diesel goes to the DHT, and heavy gas oil and unconverted oil are blended to SCO. The Eb-Bed HCU is a significant user of hydrogen.
- **GOHT**—The gas oil hydrotreating unit (GOHT) desulfurizes heavy gas oil from the DRU, VDU, and coking units. The GOHT is a significant user of hydrogen.
- **Naphtha Hydrotreating**—The Naphtha hydrotreating unit is designed to process C4s together with naphtha from the coker or Eb-Bed units, as well as naphtha from the DHT and from the GOHT as needed to meet SCO specifications. Naphtha and C4s from the NHT are blended to SCO. The NHT is a low to moderate user of hydrogen.
- **DHT**—The Distillate Hydrotreating Unit (DHT) processes distillate from the DRU, coker, GOHT and Eb-Bed hydrocracking units. Distillate sulfur is targeted to be less than 250 ppm in SCO. The DHT unit is a significant user of hydrogen.
- **Hydrogen**—Hydrogen is produced from natural gas via steam methane reforming. Process heat to the hydrogen plant is supplied by fuel gas which is supplemented by natural gas as needed. The hydrogen plant includes a pressure swing adsorption unit (PSA) to achieve 99%+ purity.
- **Sulfur Plant**—Sulfur is recovered in the sulfur plant from H_2S that is produced during the upgrading steps. The sulfur plant consists of a Claus unit, Tail Gas Treating Plant, Amine Regeneration, and Sour Water stripper.
- **Gas Plants**—The gas plant is designed to remove 90% of the C4s from the fuel gas, which consists of C1s, C2s and C3s and any unrecovered C4s. Process units in the Gas Plant include a Primary Absorber, Stripper, Debutanizer, and Amine Treating.

Upgrader Modeling

Modeling of the two upgrading configurations uses PetroPlan, a software system supplied by AMI Consultants. By performing block-by-block calculations, all streams (bitumen, diluent, intermediate and blended products) flowing between process blocks are calculated and managed. Each block uses a set of nonlinear equations to predict yields, product properties, and utility consumption. Customization features of PetroPlan were used to accurately represent

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all feedstocks, products, and technologies evaluated in the study. Individual process unit representations were developed using data and models for yields, utilities, *etc*. developed by Jacobs Consultancy as well as input from licensors and other parties where available and appropriate. Jacobs Consultancy has performed numerous bitumen and ultra-heavy crude upgrading studies for clients in Canada and elsewhere and the models used in this analysis reflect the experience and knowledge gained from this work.

PetroPlan flow diagrams for each of the two Upgrading schemes are shown in Figures 4-3 and 4-4. Bitumen rates to each configuration were adjusted to produce 140,000 BPD of SCO for the downstream refinery. In the case of the coking-based upgrader, the bitumen rate is 161,146 BPD. As a result of leaving the unconverted oil in the SCO and because of volume expansion as a result of hydrogen addition, the bitumen rate to the Eb-Bed based upgrader is 136,352 BPD to produce 140,000 BPD of SCO for refining.

Process Unit Capacity

Process unit capacity for the two upgrading configurations is shown in Table 4-2. The bitumen rate to produce 140,000 BPD of SCO is significantly lower with the Eb-Bed upgrader. However, hydrogen consumption in the EB-Bed configuration is 90% higher than in the Coking configuration. It takes 1,600 SCFB of hydrogen to upgrade each barrel of bitumen in the Eb-Bed configuration versus 710 SCFB to produce the same amount of SCO in the coking configuration.

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Table 4-2.
Processing Capacity

	Units	Coker	Eb-Bed
Feeds to Upgrading			
Bitumen	BPSD	161,446	136,352
API		8.42	8.42
Sulfur	wt%	4.81	4.81
Products			
SCO	BPSD	140,003	140,002
Process Unit Capacity			
DRU	BPSD	226,024	190,893
Vacuum Unit	BPSD	190,521	160,908
Coking Unit	BPSD	82,315	0
Ebulating Bed HCU	BPSD	0	69,521
Naphtha Hydrotreater	BPSD	27,223	16,524
Diesel Hydrotreater	BPSD	50,049	40,009
Gas Oil Hydrotreating Unit	BPSD	69,829	45,407
Sulfur Plant	MTD	892	977
H2 Plant (SMR)	MMSCFD	115	217
Hydrogen Balance	(100% H2)		
Producers			
H2 Plant	MMSCFD	114.5	217.1
Consumers			
EB-HCU	MMSCFD	0.0	-139.9
NHT	MMSCFD	-24.9	-14.0
MGOHT	MMSCFD	-41.1	-26.9
DHT	MMSCFD	-48.5	-36.2
Total H2 Consumed	MMSCFD	-114.5	-217.1

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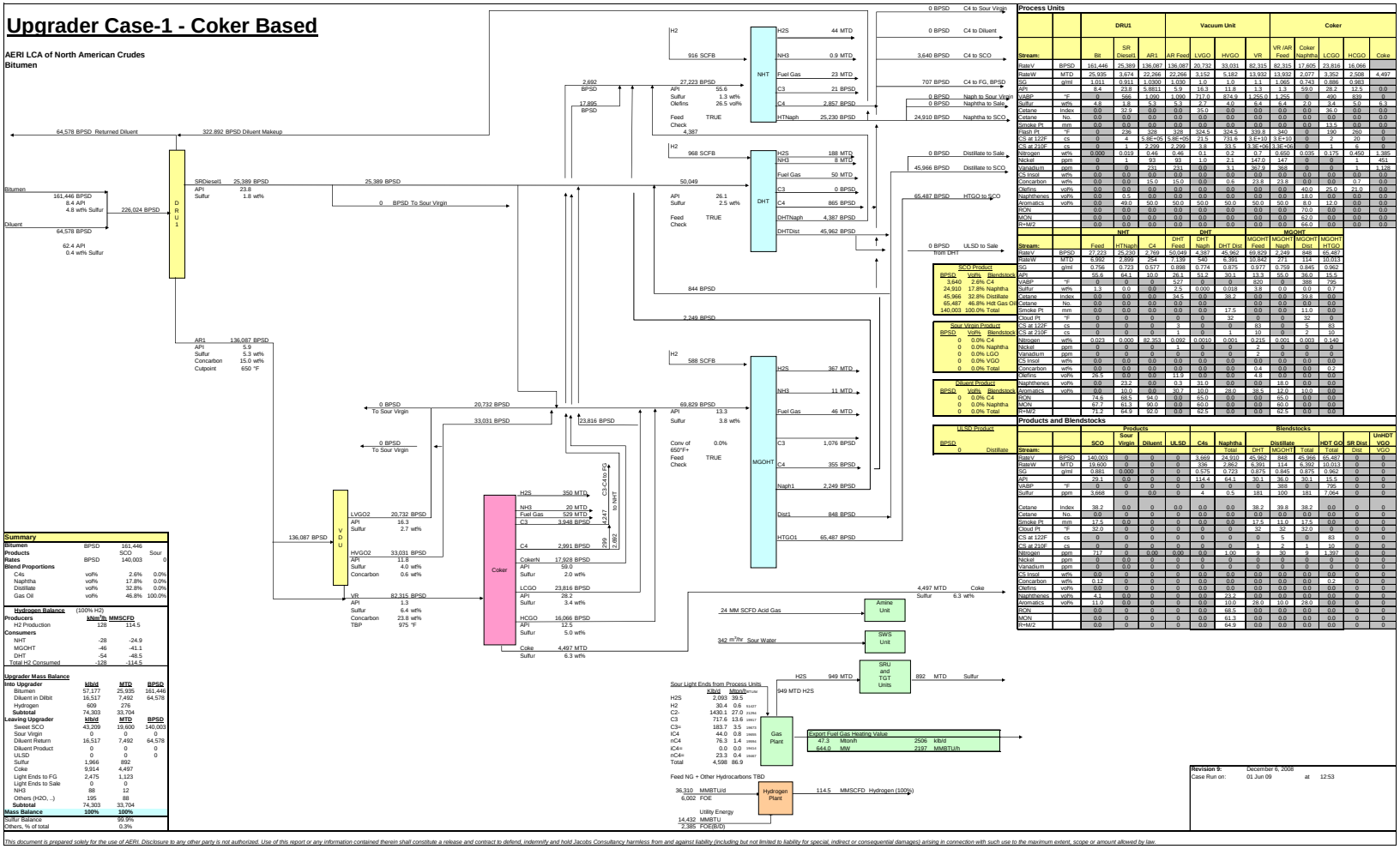
Figure 4-3.
Coking Based Upgrader to Produce 140,000 BPD of SCO for Refining



Process Units

		DRU1			Vacuum Unit			Coker				
Stream:		Bit	SR Diesel1	AR1	AR Feed	LVGO	HVGO	VR	VR /AR Feed	Coker Naphtha	LCGO	HCGO	Coke
RateV	BPSD	161,446	25,389	136,087	136,087	20,732	33,031	82,315	82,315	17,605	23,816	16,066	
RateW	MTD	25,935	3,674	22,266	22,266	3,152	5,182	13,932	13,932	2,077	3,352	2,508	4,497
SG	g/ml	1.011	0.911	1.0300	1.030	1.0	1.0	1.1	1.065	0.743	0.888	0.983	
API		8.4	23.8	5.9811	5.9	16.3	11.8	1.3	1.3	59.0	28.2	12.5	0.0
VABP	°F	0	566	1,090	1,090	717.0	874.9	1,255.0	1,255	0	490	839	0
Sulfur	wt%	4.8	1.8	5.3	5.3	2.7	4.0	6.4	6.4	2.0	3.4	5.0	6.3
Cetane	Index	8.4	32.9	0.0	0.0	35.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0
Cetane	No.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Smoke Pt	mm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	0.0	0.0
Flash Pt	°F	0	236	328	328	324.5	324.5	339.8	340	0	190	260	0
CS at 122F	cs	0	4	5.8E+05	5.8E+05	21.5	731.8	3.E+10	3.E+10	0	2	20	0
CS at 210F	cs	0	1	2,299	2,299	3.8	33.5	3.1E+04	3.1E+04	0	1	6	0
Nitrogen	wt%	0.000	0.019	0.46	0.46	0.1	0.2	0.7	0.650	0.035	0.175	0.450	1.385
Nickel	ppm	0	1	93	93	1.0	2.1	147.0	147	0	0	1	451
Vanadium	ppm	0	0	231	231	0.0	3.1	367.9	368	0	0	1	1,128
CS Insol	wt%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concarbon	wt%	0.0	0.0	15.0	15.0	0.0	0.6	23.8	23.8	0.0	0.0	0.7	0.0
Olefins	vol%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	25.0	21.0	0.0
Naphthenes	vol%	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0
Aromatics	vol%	0.0	49.0	50.0	50.0	50.0	50.0	50.0	50.0	8.0	12.0	0.0	0.0
RON		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0
MON		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.0	0.0	0.0	0.0
R+M/2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	66.0	0.0	0.0	0.0

		NHT	DHT		MGOHT			
Stream:		Feed	HTNaph	C4	DHT Feed	DHT Naph	DHT Dist	MGOHT Feed	MGOHT Naph	MGOHT Dist	MGOHT HTGO
RateV	BPSD	27,223	25,230	2,769	50,049	4,387	45,962	69,829	2,249	848	65,487
RateW	MTD	5,992	2,899	254	7,139	540	6,391	10,842	271	114	10,013
SG	g/ml	0.756	0.723	0.577	0.898	0.774	0.875	0.977	0.759	0.845	0.962
API		55.6	64.1	10.0	26.1	51.2	30.1	13.3	55.9	36.0	15.5
VABP	°F	0	0	0	527	0	0	820	0	368	795
Sulfur	wt%	1.3	0.0	0.0	2.5	0.000	0.018	3.8	0.0	0.0	0.7
Cetane	Index	0.0	0.0	0.0	34.5	0.0	38.2	0.0	0.0	39.8	0.0
Cetane	No.	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0
Smoke Pt	mm	0.0	0.0	0.0	0.0	0.0	17.5	0.0	0.0	11.0	0.0
Cloud Pt	°F	0	0	0	0	0	32	0	0	32	0
CS at 122F	cs	0	0	0	3	0	0	83	0	1	83
CS at 210F	cs	0	0	0	1	0	1	10	0	2	10
Nitrogen	wt%	0.023	0.000	82.353	0.092	0.0010	0.001	0.215	0.001	0.003	0.140
Nickel	ppm	0	0	0	1	0	0	2	0	0	0
Vanadium	ppm	0	0	0	0	0	0	2	0	0	0
CS Insol	wt%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concarbon	wt%	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.2
Olefins	vol%	26.5	0.0	0.0	11.9	0.0	0.0	4.8	0.0	0.0	0.0
Naphthenes	vol%	0.0	23.2	0.0	9.3	31.0	0.0	0.0	18.0	0.0	0.0
Aromatics	vol%	0.0	10.0	0.0	30.7	10.0	28.0	38.5	12.0	10.0	0.0
RON		74.6	68.5	94.0	0.0	65.0	0.0	0.0	65.0	0.0	0.0
MON		67.7	61.3	90.0	0.0	60.0	0.0	0.0	60.0	0.0	0.0
R+M/2		71.2	64.9	92.0	0.0	62.5	0.0	0.0	62.5	0.0	0.0

Products and Blendstocks

		Products				Blendstocks							
		SCO	Sour Virgin	Diluent	ULSD	C4s	Naphtha		Distillate		HDT GO	SR Dist	UnHDT VGO
Stream:							Total	DHT	MGOHT	Total	Total	Dist	VGO
RateV	BPSD	140,003	0	0	0	3,669	24,910	45,962	848	45,966	65,487	0	0
RateW	MTD	19,600	0	0	0	336	2,862	6,391	114	6,392	10,013	0	0
SG	g/ml	0.881	0.000	0	0	0.575	0.723	0.875	0.845	0.875	0.962	0	0
API		29.1	0.0	0	0	114.4	64.1	30.1	36.0	30.1	15.5	0	0
VABP	°F	0	0	0	0	0	0	0	368	0	795	0	0
Sulfur	ppm	3,668	0	0.0	0	4	0.5	181	100	181	7,064	0	0
Cetane	Index	38.2	0.0	0	0.0	0.0	0.0	38.2	39.8	38.2	0.0	0	0
Cetane	No.	0.0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Smoke Pt	mm	17.5	0.0	0	0	0.0	0.0	17.5	11.0	17.5	0.0	0	0
Cloud Pt	°F	32.0	0	0	0	0	0	32	32	32	0	0	0
CS at 122F	cs	0	0	0	0	0	0	0	5	0	83	0	0
CS at 210F	cs	0	0	0	0	0	0	1	2	1	10	0	0
Nitrogen	ppm	717	0	0.00	0.00	0.0	1.00	9	30	9	1,397	0	0
Nickel	ppm	0	0.0	0	0	0	0	0	0	0	0	0	0
Vanadium	ppm	0	0.0	0	0	0	0	0	0	0	0	0	0
CS Insol	wt%	0.0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Concarbon	wt%	0.12	0	0	0	0.0	0.0	0.0	0.0	0.0	0.2	0	0
Olefins	vol%	0.0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Naphthenes	vol%	4.1	0.0	0	0	0.0	23.2	0.0	0.0	0.0	0.0	0	0
Aromatics	vol%	11.0	0.0	0	0	0.0	10.0	28.0	10.0	28.0	0.0	0	0
RON		0.0	0	0	0	0.0	68.5	0.0	0.0	0.0	0.0	0	0
MON		0.0	0	0	0	0.0	61.3	0.0	0.0	0.0	0.0	0	0
R+M/2		0.0	0	0	0	0.0	64.9	0.0	0.0	0.0	0.0	0	0

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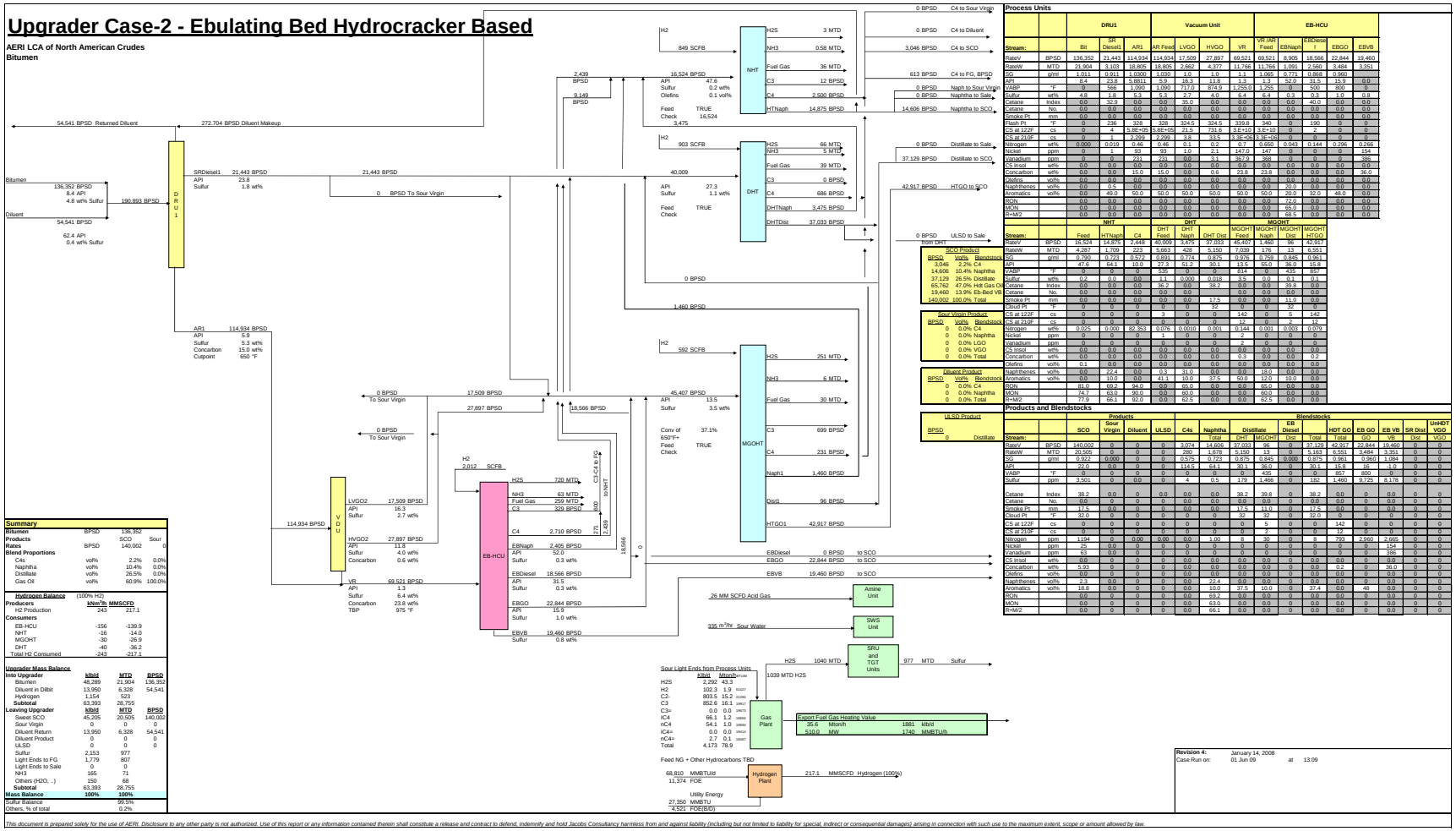
Figure 4-4.
Eb-Bed Based Upgrader to Produce 140,000 BPD of SCO for Refining



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Products

Products from the two upgrading configurations are shown in Table 4-3. The coking configuration produces 61 pounds of coke for every barrel of bitumen processed. This coke is assumed to be stored and not used elsewhere. More sulfur is produced from the Eb-Bed configuration as a result of converting and desulfurizing some of the more refractory bottoms material, which goes to coke in the coking-based upgrader. The practice of storing coke is typical. The transport costs of marketing the material from Alberta exceed its value.

Table 4-3.
Products from Upgrading

Crude	Units	**Coker**	**Eb-Bed**
Feeds to Upgading or Refining			
Bitumen	BPSD	161,446	136,352
Products			
SCO	BPSD	140,003	140,002
Coke	Klb/day	9,914	0
Sulfur	Klb/day	1,966	2,153
Diluent Return	BPSD	64,578	54,539

SCO Composition

The SCO composition from the two upgraders is shown in Table 4-4. The quality of heavy gas oil in SCO from the Eb-Bed is higher than from the coker-based upgrader. However, the presence of unconverted oil in SCO from the Eb-Bed configuration means that the refinery that processes this SCO will need an outlet for unconverted oil, either fuel oil or coking.

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Table 4-4.
SCO Quality from Upgrading

		Coker	Eb-Bed
Whole SCO			
Production Rate	BPSD	140,003	140,002
API		29.1	22.0
Sulfur	ppm	3,670	3,500
Nitrogen	ppm	720	1,190
C4			
Proportion in SCO	vol%	2.6	2.2
Naphtha			
Proportion in SCO	vol%	17.8	10.4
API		64.1	64.1
Sulfur	ppm	0.5	0.5
Nitrogen	ppm	1.00	1.00
RON		68.5	69.2
Distillate			
Proportion in SCO	vol%	32.8	26.5
API		30.1	30.1
Sulfur	ppm	180	180
Cetane	Index	38.2	38.2
Nitrogen	ppm	9.23	7.61
Gas Oil			
Proportion in SCO	vol%	46.8	47.0
API		15.5	15.8
Sulfur	ppm	7,060	950
Nitrogen	ppm	1,400	520
Unconverted Oil			
Proportion in SCO	vol%		14
API			-1.0
Sulfur	ppm		8,180
Nitrogen	ppm		2,660
Concarbon	wt%		36.0

Determining GHG Emissions from Upgrading Bitumen

Determining the energy and GHG emissions for upgrading bitumen to SCO is an important part of the life cycle assessment process and involves determining the energy and GHG burden from producing bitumen—as well as the burden brought in with the bitumen—and energy sources used in the upgrading process. The first step is to determine the utilities consumed in upgrading. Next, the utilities are distributed to the products based on their lower heating value. Bitumen is distributed to the products in the same manner so that the upstream burden from bitumen production and transportation can be added later. Finally, the utilities— which are reported in units like lb/hr of steam and boiler feed water and gallons per minute of cooling water— is

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converted to units of energy such as kW of electric power and MM BTU/hr of fuel gas or natural gas.

The methodology for distributing utilities to the products is the same as used in the refining process, described in this report. A brief overview of the steps in distributing the utilities and feeds to the products is next. For more detail, please see Section 5 in the refining section.

Utility Consumption

GHG emissions correlate with the energy used to produce SCO. Some of the utilities are produced internal to the upgrader and some are imported. In the configurations examined here, it was assumed that the electric power was produced from natural gas fired as part of cogeneration practiced in the oil sands region of Canada for bitumen production. The following utilities are consumed in the upgraders:

- Electric Power—produced from natural gas as part of steam cogeneration
- Natural Gas—imported
- Fuel Gas—produced in the upgrader
- Steam—produced in the upgrader and from cogeneration of power
- Boiler Feed Water—produced in the upgrader
- Condensate—produced in the upgrader
- Cooling Water—circulated in the upgrader

Table 4-5 shows the direct and indirect utilities needed to upgrade 161 KBPD of bitumen in a coking-based upgrader. Direct utilities are those used by the process units. Indirect utilities are those used by the utility plants to generate steam, cooling water, boiler feed water, hydrogen, *etc*. In addition, generation of power by cogen also generates steam that is available for the process units. This same methodology is used to distribute feeds and energy to the products from the Eb-Bed upgrader.

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Table 4-5.
Utility Consumption for Coking Based Upgrader

Utility Summary									
								Fuel Consumed	
Process Unit	**Capacity**	**Units**	**Hydrogen** Klb/day	**Electric** Power KW	**Steam** Klb/hr	**Boiler** Feed Water k#/hr	**Cooling Water** GPM	**Fuel Gas** MM BTU/hr	**Natural Gas** MM BTU/h
Upgrader									
Crude Unit	226,024	BSD Chg.	0	-7252	-60	0	-624	-330	0
Vacuum Unit	190,521	BSD Chg.	0	-3017	-84	0	-11226	-294	0
Coking Unit	82,315	BSD Chg.	0	-7203	59	-178	-5305	-449	0
MGOHT Hydroprocessing Unit	69,829	BPSD	-219	-20221	33	-135	-180	-102	0
Other Process Units			-390	-35868	-250	-70	-10252	-110.1	-43.9
Sulfur Recovery									
Sulfur Plant	892	MTD		-3,715	242	-246	0	0	0
Amine Regen	24	MM SCFD AG		-3,012	-251	0	-1,500	0	0
SW Stripper	758	Klb/h		-225	-70	0	-72	0	0
Utilities									
H2 Plant (SMR)	115	MMSCFD	609.0	-3,574	100	-236	-844	-601	-1,513
Power Plant (GT/HRSG)	73	MW	0	73,355	293	-296	0	0	-770
Dearators	1,429	Klb BFW	0	-1,343	-118	1429	0	0	0
Demin Plant	919	Klb/h	0	0	0	0	0	0	0
Cooling Towers	37,026	gpm	0	-926	0	0	37,026	0	0
HP MP Letdowns	315	Klb/h	0	0	0	0	0	0	0
MP LP Letdowns	386	Klb/h	0	0	0	0	0	0	0
HHP Steam Turbine Generator	158	Klb/h	0	13,000	-158	0	-7,022	0	0
Process Boilers	265	Klb/h	0	0	265	-268	0	-312	0
Direct + Indirect Utilities									
Total Direct			-999.4	-116,381	-382	-629	-29,160	-1,284	-44
Total Indirect			609.0	80,512	382	629	29,160	-913	-2,283
TOTALS			**-390.4**	**-35,868**	0	**0**	**0**	**-2,197**	**-2,327**

Net Fuel Gas deficit	0	MM BTU/hr	**Power**		Power Produced Net
Natural Gas Import	-2327	MM BTU/hr			
Net Natural Gas Usage				Power	KW
For H2 Plant	-1513	MM BTU/hr	**Imported**	0.0%	0
For Miscellaneous	-44	MM BTU/hr	**Gas Turbine**	85.3%	73,355
For Gas Turbine	-770	MM BTU/hr	**Steam Turbine**	14.7%	12,661
To Balance Fuel Gas needs	0	MM BTU/hr	**Total**	100.0%	86,016

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A comparison of the utilities for the Coking and Eb-Bed based upgraders is given in Table 4-6. Note that the consumption of utilities such as steam, cooling water, and boiler feed water used in processing (Total Direct) is balanced in most cases with the production of utilities (Total Indirect) for both upgrader configurations. Electricity is balanced in these configurations because it is generated internally by cogeneration. Fuel gas is generated in the upgrader. Natural gas is brought in from outside the battery limits of the upgrader.

Table 4-6.
Utilities for Coking vs. Eb-Bed Upgrading to Produce 140,000 BPD of SCO

	Coking Based Upgrader			Eb-Bed Based Upgrader		
	Total Direct	Total Indirect	Totals	Total Direct	Total Indirect	Totals
Hydrogen, MM SCFD	-115	115	0	-217	217	0
Electric Power, kw	-86,016	86,016	0	-71,890	71,890	0
Steam, Klb/hr	-382	382	0	-328	328	0
Boiler Feed Water, klb/hr	-629	629	0	-550	550	0
Cooling Water, gpm	-29,160	29,160	0	-24,535	24,535	0
Fuel Gas, MM BTU/hr	-1,284	-913	-2,197	-1,056	-1,140	-2,196
Natural Gas, MM BTU/hr	-44	-2,283	-2,327	-44	-3,594	-3,638

Distributing Utilities and Feeds to Products

The principle behind distributing utilities is that, starting with the first process unit (the DRU), the energy needed to make each product is tracked through each processing step. In addition, each feed and utility brought into the refinery or upgrader from outside carries an energy burden with it that must also be distributed to the products. Distribution is based on LHV of each product; thus, the energy burden brought in with the feeds plus the energy used in processing is distributed to each product based on the total energy carried with it divided by the total energy carried by all the product streams. This prorating uses the energy carried by each stream, which is determined from its LHV (energy/wt), and the total weight of that stream. (LHV is calculated using the API method (*API Technical Data Book*).

All utilities shown in Table 4-5 are tracked to the products. For example, 84 klb/hr of steam used in the VDU are tracked to LVGO, HVGO and vacuum resid, which are the products from the VDU. The steam from the VDU that is distributed to vacuum resid goes to the coker and ends up in the coker C4s, coker naphtha, coker LCGO, HCGO, and coke together with the steam that is used in the coker.

For the upgraders, the process begins with bitumen, which carries with it the upstream energy from production. Natural gas carries with it a processing burden from its production, as does electricity if imported. Conversion of energy to GHG emissions uses standard factors from

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GREET to convert the energy used in processing to GHG gases—N_2O, CH_4 and CO_2 (see Table 5-11 in the Refining section of this report). Conversion of these GHG gases to GHG warming potential (GWP) uses the factors from GREET stemming from the IPCC (see Table 5-13 in the Refining section).

The upstream production burdens for bitumen, natural gas, and electricity were not distributed in processing. Instead, the amount of bitumen and the amount of energy brought into the upgrader were distributed to the products; the upstream energy and GHG burdens were added later when all the emissions for WTW were rolled up.

Energy and bitumen content were tracked to intermediate products that end up in final products. They were not tracked to intermediate streams that were consumed in the upgrader. Thus, bitumen and energy were tracked to C4s that ended up in SCO. Bitumen and energy were not tracked to fuel gas components, which includes all of the C2- and C3s and some of the C4s not recovered. (Note that recovery of C3s from refinery fuel gas is much greater than assumed for the upgraders.)

Example of Distribution of Energy and Feeds to Products

An example showing the distribution of bitumen, electricity and hydrogen through the upgrading steps in the coking-based upgrader is shown in Figures 4-5 through 4-11.

Starting with the DRU, dilbit feed processing was modeled in two pieces: bitumen processing (shown in Figure 4-5) and diluent (shown in Figure 4-6). While bitumen continues through the upgrading steps, the majority of diluent is returned to the bitumen production site from the DRU, with only a small portion representing material heavier than naphtha continuing through upgrading. This portion is made up from naphtha produced in the upgrader so that diluent brought in with bitumen balances diluent returned to the production site.

Figure 4-5 shows how 161 KBPD of bitumen is fractioned in the DRU to produce LGO (light gas oil, which is distillate) and AR (atmospheric resid). It requires 5180 kWhr/hr of electricity (772 kWhr/bbl) to process the bitumen. This electricity is distributed to the LGO and AR, based on their net heating values calculated from their LHV and the weight produced. Bitumen is also distributed to the products using the same methodology. AR is the largest stream and gets the largest share of electricity and bitumen. There is no hydrogen consumed in the DRU. Distribution of the other utilities, cooling water, steam, *etc*. follows the same procedure, but is not shown here to keep the example simple.

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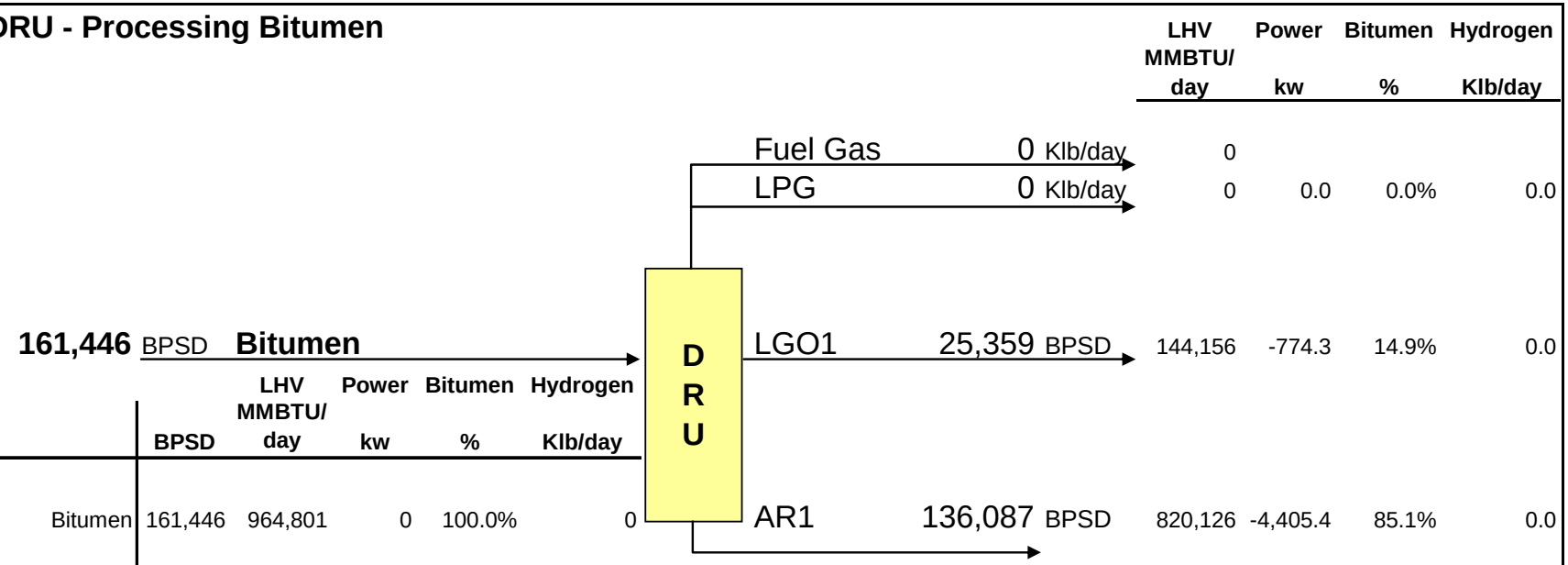
Figure 4-5.
DRU Processing Bitumen—Coker Based Upgrader

DRU - Processing Bitumen



	BPSD	LHV MMBTU/ day	Power kw	Bitumen %	Hydrogen Klb/day
Bitumen	161,446	964,801	0	100.0%	0
From Feeds	161,446	964,801	0	100.0%	0
From Process			-5,180		0
Total	161,446	964,801	-5,180	100.0%	0

	LHV MMBTU/ day	Power kw	Bitumen %	Hydrogen Klb/day
Fuel Gas	0			
LPG	0	0.0	0.0%	0.0
LGO1	144,156	-774.3	14.9%	0.0
AR1	820,126	-4,405.4	85.1%	0.0
Total	964,282	-5,180	100.0%	0

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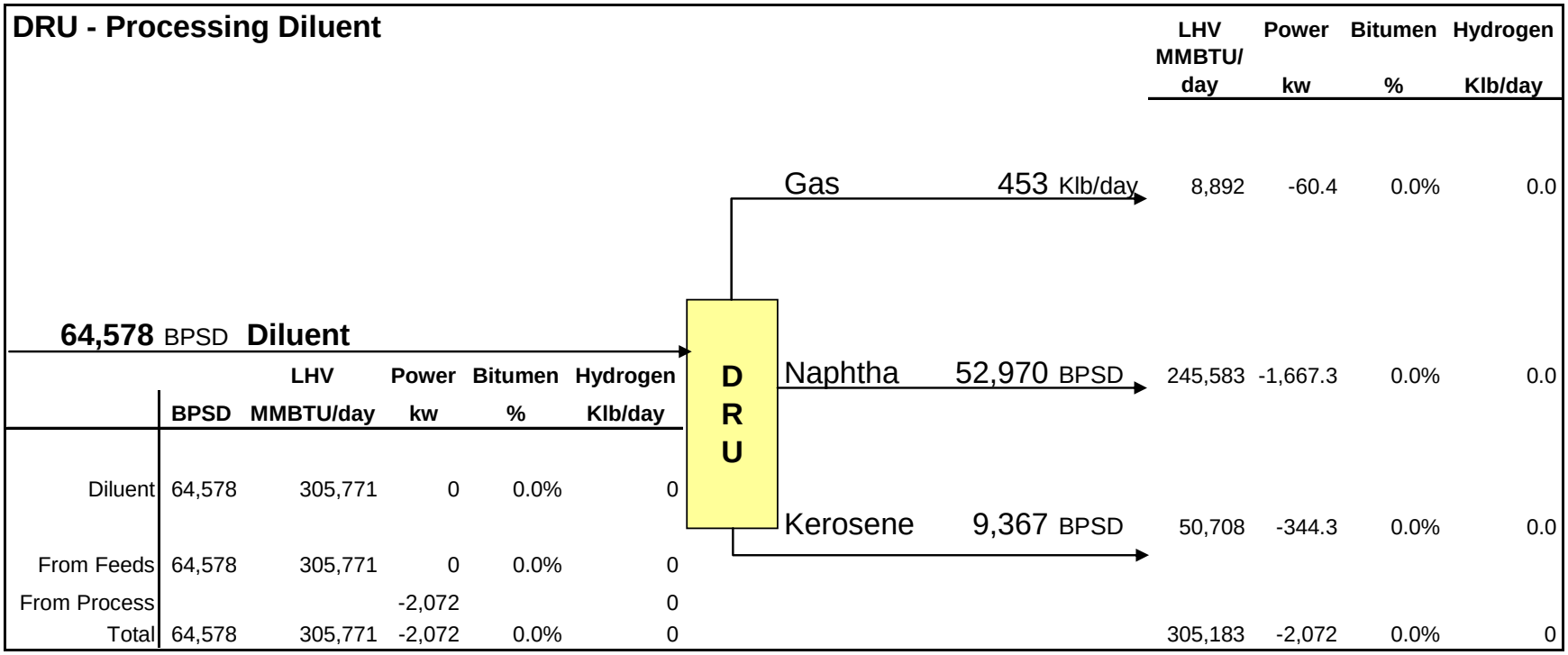
Figure 4-6.
DRU Processing Diluent—Coker Based Upgrader

DRU - Processing Diluent



	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
Diluent	64,578	305,771	0	0.0%	0
From Feeds	64,578	305,771	0	0.0%	0
From Process			-2,072		0
Total	64,578	305,771	-2,072	0.0%	0

		LHV MMBTU/ day	Power kw	Bitumen %	Hydrogen Klb/day
Gas	453 Klb/day	8,892	-60.4	0.0%	0.0
Naphtha	52,970 BPSD	245,583	-1,667.3	0.0%	0.0
Kerosene	9,367 BPSD	50,708	-344.3	0.0%	0.0
Total		305,183	-2,072	0.0%	0

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Figure 4-7.
VDU—Coker-Based Upgrader

Vacuum Unit - Processing Atmospheric Resid

136,087 BPSD **AR**

	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
AR	136,087	820,126	-4,405	85.1%	0
From Feeds	136,087	820,126	-4,405	85.1%	0
From Process			-3,017		0
Total	136,087	820,126	-7,422	85.1%	0

VDU

		LHV MMBTU/ day	Power kw	Bitumen %	Hydrogen Klb/day
Fuel Gas	0 Klb/day	0			
LPG	0 Klb/day	0	0.0	0.0%	0.0
		0	0.0	0.0%	0.0
LVGO2	20,732 BPSD	121,287	-1,098.0	12.6%	0.0
HVGO2	33,031 BPSD	195,476	-1,769.7	20.3%	0.0
					0.0
VR	**82,315** BPSD	503,042	-4,554.2	52.2%	
					0.0
		819,805	-7,422	85.1%	0

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Figure 4-8.
Coker—Coker Based Upgrader

Coker Unit - Processing Vacuum Resid

82,315 BPSD **VR**

	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
VR	82,315	503,042	-4,554	52.2%	0
From Feeds	82,315	503,042	-4,554	52.2%	0
From Process			-7,203		0
Total	82,315	503,042	-11,757	52.2%	0

Coker

		LHV MMBTU /day	Power kw	Bitumen %	Hydrogen Klb/day
H2S	771 Klb/day	5,036	0.0	0.0%	0.0
NH3	201 Klb/day	0	0.0	0.0%	0.0
Fuel Gas	1,991 Klb/day	41,178	0.0	0.0%	0.0
LPG	504 Klb/day	9,891	-261.7	1.2%	0.0
CokerN	17,605 BPSD	83,815	-2,217.4	9.8%	0.0
LCGO	23,816 BPSD	130,934	-3,463.9	15.4%	0.0
HCGO	16,066 BPSD	93,998	-2,486.8	11.0%	0.0
Coke	**9,914** Klb/day	125,758	-3,327.0	14.8%	0.0
Total		485,574	-11,757	52.2%	0

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Figure 4-9.
GOHT—Coker Based Upgrader

MGOHT Unit

588 SCFB **H2**
-218.6 **Klb/day**

69,829 BPSD **Gas Oil**

	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
LVGO	20,732	121,287	-1,098	12.6%	0
HVGO	33,031	195,476	-1,770	20.3%	0
HCGO	16,066	93,998	-2,487	11.0%	0
From Feeds	69,829	410,761	-5,355	43.9%	0
From Process			-20,221		-219
Total	69,829	410,761	-25,576	43.9%	-219

MGOHT

		LHV MMBTU /day	Power kw	Bitumen %	Hydrogen Klb/day
H2S	809 Klb/day	5,286	0	0.0%	0.0
NH3	25 Klb/day	0	0	0.0%	0.0
Fuel Gas	311 Klb/day	6,673	0	0	0
LPG	64 Klb/day	1,256	-79	0.1%	0.7
HTNaph	2,249 BPSD	11,114	-698	1.2%	6.0
Distillate	848 BPSD	4,611	-289	0.5%	2.5
HT'd GO	65,487 BPSD	390,492	-24,510	42.1%	209.4
		414,145	-25,576	43.9%	218.6

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Figure 4-10.
DHT—Coker Based Upgrader

DHT Unit

968 SCFB **H2**
-258 klb/day

50,049 BPSD **Distillate**

	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
SR Distillate	25,389	144,332	-775	14.9%	0
Coker Distillate	23,816	130,934	-3,464	15.4%	0
MGOHT Distillate	844	4,588	-288	0.5%	-2
From Feeds	50,049	279,853	-4,527	30.8%	
From Process			-14,806		-260
Total	50,049	279,853	-19,333	30.8%	-260

DHT

		LHV MMBTU /day	Power kw	Bitumen %	Hydrogen Klb/day
H2S	416 Klb/day	2,715	0.0	0.0%	0.0
NH3	81 Klb/day	0	0.0	0.0%	0.0
Fuel Gas	140 Klb/day	3,350	0.0	0.0%	0.00
LPG	156 Klb/day	3,059	-209.5	0.3%	-2.8
HTNaph	4,387 BPSD	22,111	-1,514.7	2.4%	-20.4
Distillate	45,962 BPSD	257,042	-17,609.1	28.1%	-237.1
		285,561	-19,333.4	30.8%	-260

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Figure 4-11.
NHT—Coker Based Upgrader

NHT Unit

916 SCFB **H2**

-133 klb/day

24,530 BPSD **Naphtha**

	BPSD	LHV MMBTU/day	Power kw	Bitumen %	Hydrogen Klb/day
Coker Naphtha	17,895	85,160	-2,226	9.8%	0
DHT/ MGOHT Naphtha	6,636	33,227	-2,212	3.6%	-26
From Feeds	24,530	118,388	-4,439	13.5%	-26
From Process			-7,501		-133
Total	24,530	118,388	-11,939	13.5%	-159

NHT

		LHV MMBTU /day	Power kw	Bitumen %	Hydrogen Klb/day
H2S	98 Klb/day	637	0.0	0.0%	0.0
NH3	6 Klb/day	0	0.0	0.0%	0.0
Fuel Gas	63 Klb/day	1,539	0.0	0.0%	0.0
LPG	16 Klb/day	312	-31.3	0.0%	-0.4
HTNaph	25,230 BPSD	118,705	-11,908.1	13.4%	-158.5
		119,017	-11,939	13.5%	-159

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Fractionation of diluent in the DRU is shown in Figure 4-6. The major products are naphtha (which is returned to the production site) and kerosene (which goes on to further upgrading and is made up from naphtha produced in the upgrader). As shown in Figure 4-6, LPG, naphtha, and kerosene carry shares of electricity and diluent. In the case of diluent returned to the production site, the processing burden—both from processing in the upgrader and from upstream associated with diluent production—will be distributed to the SCO product so that there is no disappearance of energy or GHG emissions. The processing burden associated with kerosene is tracked through the upgrading steps and will also end up in the SCO product.

Figure 4-7 shows the fractionation of AR in the VDU. Note that AR brings processing burden and bitumen content from the DRU, which is upstream. This upstream burden plus the processing burden in the VDU are distributed to the products from the VDU using the LHV method described.

Figure 4-8 shows processing in the coker. Again, upstream burden and processing burden in the coker are distributed to the products. Note that what comes in balances with what goes out. Also note that although there is production of H_2S, NH_3 and fuel gas, these streams are not assigned any processing burden.

Figure 4-9 shows processing of gas oil in the GOHT. Note that hydrogen consumed in the process is distributed to the products based on their heating values.

Figure 4-10 shows processing of distillate range material in the DHT. Note: some of the GOHT distillate must be reprocessed in the DHT to meet the SCO distillate sulfur specifications. As a result, there is some hydrogen burden brought in with this feed to the DHT.

Figure 4-11 shows processing of naphtha range material and coker C4s in the NHT. The feed to the NHT includes material from the DHT and GOHT, and these streams carry with them upstream hydrogen in addition to other processing burdens.

A summary of the overall ins and outs of the upgrader described above is shown in Table 4-7. Note that although processing burden is assigned to coke and to the diluent that is returned, in this life cycle analysis these burdens will be assigned to SCO. We opine this is an appropriate methodology since the SCO is ultimately consumed, whereas the diluent and the coke are not.

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Table 4-7.
Summary of Coking-Based Upgrading Showing Products and Distribution of Utilities and Dilbit

		In				Out											Error
									SCO					Coke	Diluent Return		
		Hydrogen	Diluent	Bitumen	Total	H2S	NH3	Fuel Gas	LPG	Naphtha	Distillate	Gas Oil	SCO	Coke	Diluent	Out	
Volume	BPD		64,578	161,446	226,024				3,640	24,910	45,966	65,487	140,003		64,578	204,581	
Weight	Klb/day	609	16,505	57,177	74,290	2,093	312	2,506	733	6,311	14,091	22,074	43,209	9,914	16,504	74,538	0.3%
Diluent	%		100.0%		100.0%				0.0%	0.4%	0.0%	0.0%	0.5%	0.0%	99.5%	100.0%	0.0%
Bitumen	%			100.0%	100.0%				1.7%	13.2%	28.1%	42.1%	85.1%	14.8%	0.2%	100.0%	0.0%
Hydrogen	Klb/day	609			609				4	157	237	209	607	0	2	609	0.0%
Electricity	kw				59,999				576	11,757	17,611	24,510	54,454	3,327	2,213	59,993	0.0%

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Conversion of Utilities to Primary Energy Units

Calculation of GHG and GWP requires translating utilities from units of klb/hr of steam or boiler feed water and gpm of cooling water to energy units, which are: MMBTU/hr of fuel gas and natural gas and kW of electricity. Production of steam, cooling water, hydrogen, and boiler feed water is done in the utility plants, which use energy to produce utilities for the upgrader and in some cases use utilities produced by other utility units. The energy to produce these utilities must be distributed to the products SCO, diluent and coke.

Figure 4-12 shows the factors used to convert steam, boiler feed water, cooling water, and hydrogen to fundamental energy units of MMBTU/hr of natural gas and fuel gas and kW of power.

- The utility plants on the left side of the figure show the energy needed to produce one unit of utility. For example, the dearator (BFW), which produces boiler feed water, uses 0.94 kW of electricity, and 0.0824 klb/hr of steam to generate 1 klb/hr of boiler feed water. These numbers can be calculated from the rates and the values shown in Table 4-5. Thus, the Dearator uses 1,343 kW of electricity to produce 1,429 klb/hr of boiler feed water, which translates to 0.94 kW/(klb/hr).
- Likewise, the hydrogen plant uses power, fuel gas, natural gas, boiler feed water, and cooling water to generate hydrogen. The hydrogen plant also generates steam.
- Translating these utilities into primary units of natural gas, fuel gas and electric power requires recognizing that the utility plants are interdependent. Thus, the dearator (BFW) uses steam produced in the process boilers to generate BFW. But the process boiler uses boiler feed water from the dearator. The BFW on the right side of Figure 4-12 shows power used directly plus the power to make the steam used in deaeration, which includes the component for making boiler feed water. In a similar manner, the fuel gas shown on the right side of Figure 4-12 for the BFW is higher than the fuel gas on the left side of Figure 4-12 because it includes the fuel gas used in the process boilers to make steam.

Distribution of Utilities to Products

Direct and indirect utilities used in the coking-based upgrader are shown in Table 4-8 in the fundamental units of energy. The sum of direct and indirect utilities show the amount of fuel gas, natural gas and electric power associated with the production of each product in the upgrader. Table 4-8 also shows the natural gas used in cogeneration.

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Figure 4-12.
Utility Plants—Factors for Converting Utilities to Fundamental Energy—Coker-Based Upgrader

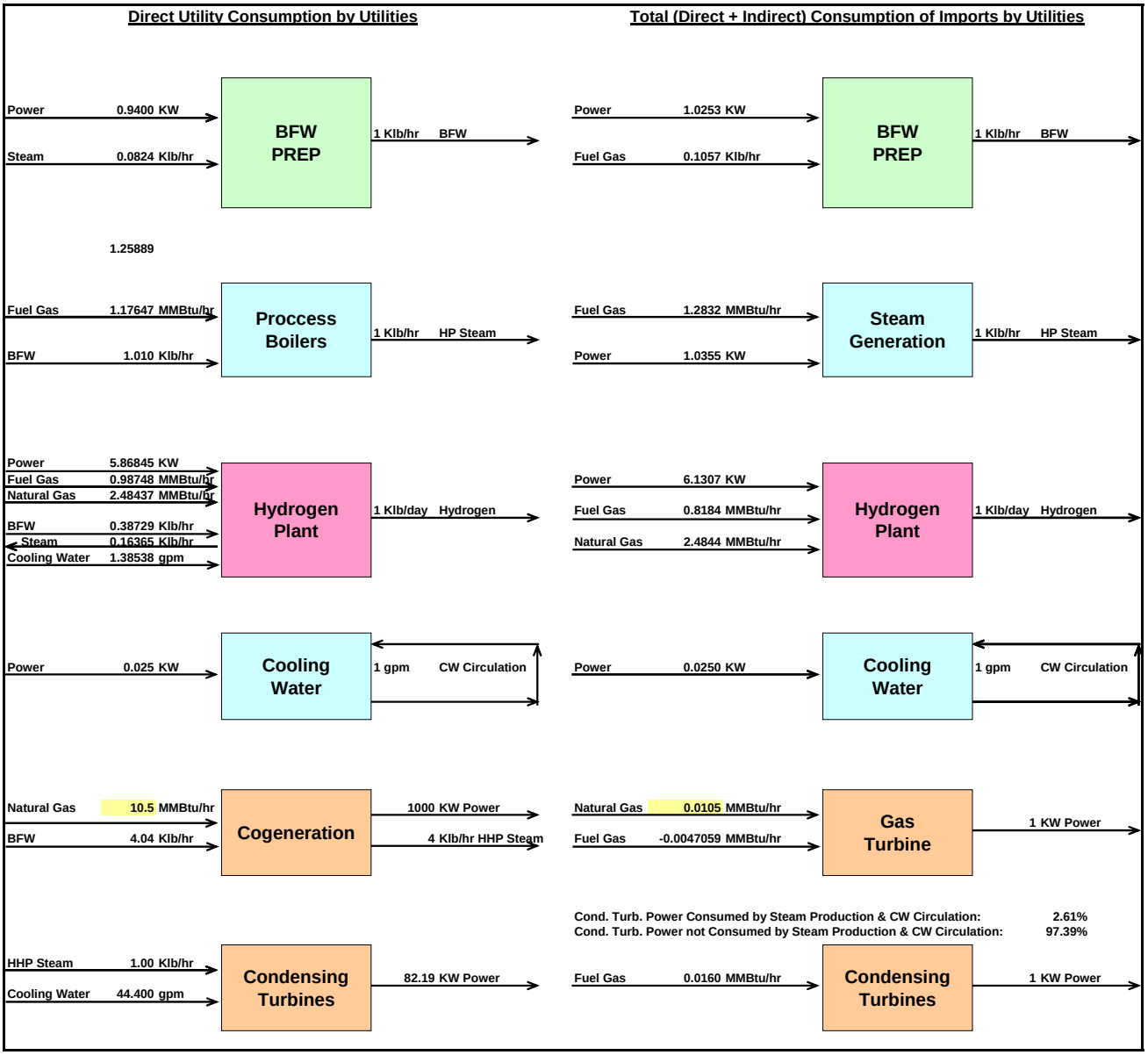

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Table 4-8.
Distribution of Utilities to Products from Coking-Based Upgrader

	Units	SCO	Coke	Sulfur	Diluent Return	Total Energy
Total Direct Utilities						
Power	KW	-63,149	-4,720	-7,038	-5,599	-80,507
Steam	Klb/hr	-242	-15	-80	-44	-382
Fuel Gas	MM BTU/hr	-969	-215	0	-100	-1,284
Natural Gas	MM BTU/hr	-28	-5	0	-11	-44
Natural Gas Used as Process Feed to H2 Plant	MM BTU/hr	0	0	0	0	0
Cooling Water	GPM	-21,555	-4,171	-1,613	-1,817	-29,156
BFW	Klb/hr	-331	-50	-246	-1	-629
Indirect Consumption of Primary Utilities						
Power	KW	-4,850	-172	-376	-105	-5,503
Fuel Gas	MMBtu/hr	-730	-17	-117	-49	-913
Natural Gas as H2 Plant Feed	MMBtu/hr	-1508	0	0	-5	-1,513
Natural Gas to CoGen	MMBtu/hr	-609	-44	-66	-51	-770
Total Primary Utility Consumption (Direct + Indirect)						
Total Power	KW	-67,999	-4,892	-7,414	-5,704	-86,009
Total Imported Power	KW	0	0	0	0	
Refinery Generated Power	KW	67,999	4,892	7,414	5,704	
Power Consumed by Steam Turbines	KW					
Total Refinery Fuel Gas Consumed	MM BTU/hr	-1,700	-231	-117	-149	2,197
Direct Fuel Gas to Products	MM BTU/hr	-969	-215	0	-100	
Indirect Fuel Gas	MM BTU/hr	-730	-17	-117	-49	
Internally Produced Fuel Gas Exported	MM BTU/hr					
Credit for Natural Gas Addded to Balance Fuel Gas Heat	MM BTU/hr	0	0	0	0	
Total Natural Gas Consumed	MM BTU/hr	-2,145	-48	-67	-67	2,327
As Neat Fuel	MM BTU/hr	-28	-5	0	-11	
Process Feed to H2 Plant	MM BTU/hr	-1,508	0	0	-5	
Imported to Supplement Fuel Gas	MM BTU/hr	0	0	0	0	
Natural Gas to Cogen	MM BTU/hr	-609	-44	-66	-51	

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GHG emissions (N_2O, CH_4 and CO_2) are calculated from the energy consumption using appropriate emission factors from GREET and then converted to GWP using the IPCC factors and reported as CO_2 equivalent emissions. Table 4-9 shows the GHG emissions reported in MTD from producing each product in the coking based upgrader. Also shown in Table 4-9 are the intrinsic emissions, which are reported in g of GHG (CO_2e) per MJ of product and are calculated from the MTD of GHG emissions and the LHV of the products. It is not surprising that SCO has much higher intrinsic GHG emissions (7.0 g/MJ) than coke (3.3 g/MJ) because the processing intensity to make SCO is much higher than to make coke. Coke sees processing only in the DRU, VDU and Coker. The streams going into SCO carry the processing burden from these three units plus the hydrotreating units and, in the case of naphtha, additional burden because naphtha from the GOHT and DHT units is reprocessed in the NHT.

Assigning GHG Emissions to SCO

The results reported in Table 4-9 show the GHG emissions for SCO, coke, sulfur and diluent returned to the production site. However, the rule for this life cycle analysis is that the burden assigned to the minor products must be assigned to the major product, which is SCO. The lower portion of Table 4-9 shows how the GHG emissions from the minor products are reassigned to SCO. As a result of moving coproduct GHG emissions to SCO, its intrinsic GHG burden increases from 7.0 g/MJ to 8.3 g/MJ.

Assigning Feed and Energy Shares to SCO

Feeds and energy brought into the upgrader carry a GHG burden from their production. To maintain the flexibility to examine different upstream GHG burdens, this life cycle analysis tracks fuel and energy shares to the products; upstream burdens will be added later. Prior discussion above showed how bitumen was tracked onto products and how fuel gas, electricity and natural gas were also tracked to the products.

Table 4-10 shows the share of electric power, fuel gas, and associated with producing each product. Also shown are the shares of bitumen and diluent associated with each product. As discussed, the shares of energy and feed must be reassigned to SCO for this life cycle analysis. Results for redistributing these feed and energy shares are shown in Table 4-10. The energy to fractionate diluent for return to the bitumen production site is assigned to SCO. The upstream burden associated with transport of dilbit will be included later. The energy and bitumen content needed to make up diluent lost in upgrading are assigned to SCO.

Specific energy and energy share for SCO after distributing coke, sulfur and diluent shares to SCO are shown at the bottom of Table 4-10.

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Table 4-9.
GHG Emissions Attributed to Products—with Reallocation of GHG Emissions to SCO—Coker-Based Upgrader

	Units	SCO	Coke	Sulfur	Diluent Return	Total
Total GHG Emissions	MTD	5,810	440	292	342	6,884
GHG Emissions from Power	MTD	0	0	0	0	0
GHG Emissions from Fuel Gas	MTD	2,642	359	182	232	3,415
GHG Emissions from Combustion of Natural Gas	MTD	47	8	0	18	73
GHG Emissions from Combustion of Natural Gas for Cogen	MTD	1,013	73	110	85	1,281
GHG Emissions from Natural Gas Used as Process Feed to H2 Plant	MTD	2,108	0	0	7	2,115
GHG Emissions from FCC Coke Used as FCC unit Process Heat	MTD	0	0	0	0	0
Total Intrinsic GHG Emissions	g/MJ	7.02	3.31	35.41	1.06	
Redistribute Byproduct GHG Emissions			440	292	342	1,074
Distribute GHG Emissions of Byproducts to Major Products						
Diluent	MTD	342				342
Coke	MTD	440				440
Sulfur	MTD	292				292
GHG Emissions before Coproduct Add Back	MTD	5,810				5,810
GHG Emissions after Coproduct Add Back	MTD	6,884				6,884
Intrinsic GHG Emissions after Byproduct GHG Add Back	g/MJ	8.31				

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Table 4-10.
Fuel Share Distribution to SCO—Coker Based Upgrader

	Units	SCO	Coke	Sulfur	Diluent Return	Total
Total Fuel and Feed Shares to Products						
Total Imported Power - GJ/hr	GJ/hr	0	0	0	0	0
Total Refinery Fuel Gas - GJ/hr	GJ/hr	-1,793	-244	-123	-157	-2,318
Total Natural Gas - GJ/hr	GJ/hr	-2,263	-51	-70	-71	-2,455
Product Heating Value	GJ/hr	34,503	5,528	344	13,438	
Diluent - Net Heating Value in Products	GJ/hr	66	0	0	13,376	
Bitumen - Net Heating Value in Products	GJ/hr	36,075	6,263	0	72	
Hydrogen - Net Heating Value in Products	GJ/hr	-1,372	0	0	-5	
GREET Inputs, Fuel Shares						
Bitumen, specific energy	GJ/GJ	1.046	1.133	0.000	0.005	
Fuel Gas, specific energy	GJ/GJ	0.052	0.044	0.358	0.012	
Electricity, specific energy	GJ/GJ	0.000	0.000	0.000	0.000	
Natural gas, specific energy	GJ/GJ	0.066	0.009	0.204	0.005	
GREET Inputs, Fuel Shares - After Coproduct Redistribution						
Bitumen, specific energy	GJ/GJ	1.2292				
Fuel Gas, specific energy	GJ/GJ	0.0672				
Electricity, specific energy	GJ/GJ	0.0000				
Natural gas, specific energy	GJ/GJ	0.0712				
Fuel Share after Redistribution to SCO						
Total Imported Power - GJ/hr	GJ/hr	0				0
Total Refinery Fuel Gas - GJ/hr	GJ/hr	-2,318				-2,318
Total Natural Gas - GJ/hr	GJ/hr	-2,455				-2,455

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Comparison of GHG Emissions from Coking vs. Eb-Bed Based Upgrading

Results for producing 140 KBPD of SCO from coking and Eb-Bed-based upgraders are shown in Table 4-11. To produce the same amount of SCO, the Eb-bed-based upgrader uses less bitumen but requires more hydrogen and energy and produces more GHG. More detail on energy and GHG emissions for the two configurations is shown in Table 4-12.

Table 4-11.
Comparison of Upgrading Schemes to Produce 140 KBPD of SCO

	Units	Coker	Eb-Bed
Bitumen to Upgrader	BPSD	161,446	136,352
Products			
SCO	BPSD	140,000	140,000
Coke	Klb/day	9,910	0
Sulfur	Klb/day	1,970	2,150
Diluent Return	BPSD	64,580	54,540
Hydrogen addition	MMSCFD	115	217
Total GHG	MTD	6,884	9,972
Intrinsic GHG Emissions			
GHG - per MJ of Bitumen	g CO2e/MJ of Bitumen	6.76	11.60
GHG - per MJ of SCO	g CO2e/MJ of SCO	8.31	11.64

As a result of the different bitumen processing rates to produce the same amount of SCO, the gap in intrinsic GHG emissions between the Eb-Bed and coking based configurations is 4.8 g GHG/MJ of bitumen but 3.3 g GHG/MJ of SCO.

Figures 4-13 and 4-14 show the contribution to intrinsic GHG emissions from each product produced in the upgrader. In our analysis, the GHG emissions from the coproducts are distributed back to SCO. Thus the intrinsic GHG emissions for SCO from the coker based upgrader are 8.3 g GHG/MJ of SCO vs. 11.6 g GHG/MJ of SCO from the Eb-Bed upgrading configuration.

It remains to be seen how the two upgrading configurations will compare on a WTW basis once the energy for bitumen production is included in the analysis.

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Figure 4-13.
Product Contribution to Upgrader GHG Footprint - g GHG/MJ of Bitumen

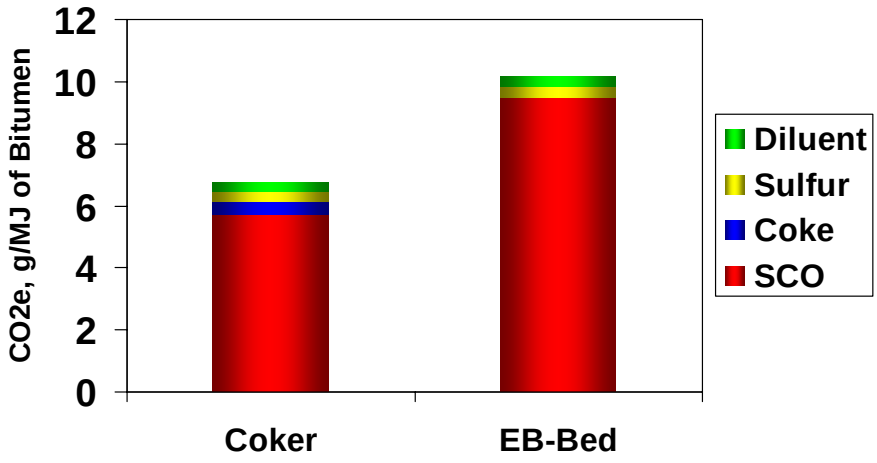

Figure 4-14.
Product Comparison to Upgrader GHG Footprint - g GHG/MJ of SCO

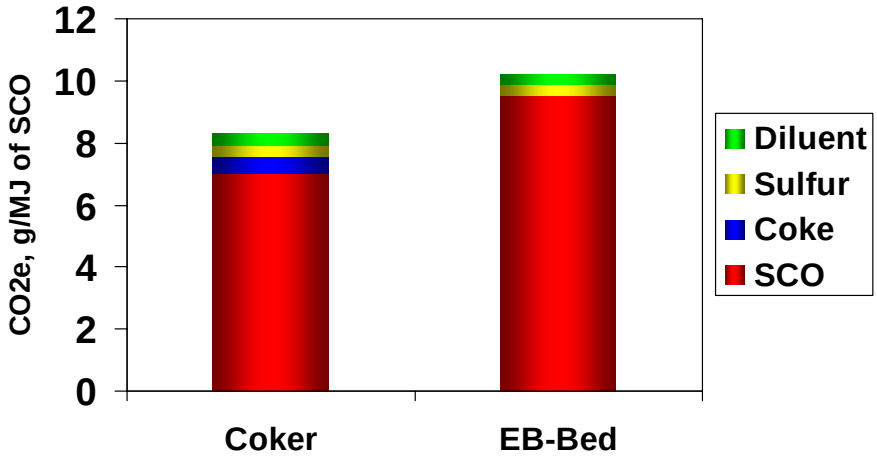

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Table 4-12.
Utility Requirements and GHG Emissions to Produce 140,000 BPD of SCO from Coking and Eb-Bed Upgrading Configurations

	Units	Coker	Eb-Bed
Utility Requirements			
Total Primary Utility Consumption (Direct + Indirect)			
Total Imported Power - GJ/hr	GJ/hr	0	0
Total Refinery Fuel Gas - GJ/hr	GJ/hr	2,318	1,836
Total Natural Gas - GJ/hr	GJ/hr	2,455	4,319
Redistribute Byproduct GHG Emissions			
SCO - GHG Emissions after Coproduct Add Back	MTD	6,884	8,753
Redistribute Byproduct Bitumen, specific energy			
SCO - Bitumen Specific Energy after Coproduct Add Back	GJ/hr	42,411	35,819
Redistribute Bproduct Fuel Gas, specific energy			
SCO - Fuel Gas Specific Energy after Coproduct Add Back	GJ/hr	2,318	1,836
Redistribute Bproduct Electricity, specific energy			
SCO - Electricity Specific Energy after Coproduct Add Back	GJ/hr	0	0
Redistribute Bproduct Natural gas, specific energy			
SCO - Natural Gas Specific Energy after Coproduct Add Back	GJ/hr	2,455	4,319
Emissions for Each Product			
SCO - GHG Burden with Byproduct GHG Add Back	Kg/GJ	8.31	10.22
GREET Inputs, Fuel Shares After Coproduct Redistribution			
SCO - Bitumen, specific energy after coproduct redistribution	GJ/GJ	1.229	1.004
SCO - Fuel Gas, specific energy after coproduct redistribution	GJ/GJ	0.067	0.051
SCO - Electricity, specific energy after coproduct redistribution	GJ/GJ	0.000	0.000
SCO - Natural gas, specific energy after coproduct redistribution	GJ/GJ	0.071	0.121

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References

API Technical Data Book, Chapter 14 Combustion, 7th ed, API, 2005

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Section 5.

Refining

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Crude Oil Refining

The processing steps in refining are designed to convert crude oil, SCO or bitumen feeds into transportation fuels. The first step in refining is fractionation of the feed into major components: naphtha, distillate, gas oil, and residual oil (resid). Subsequent steps convert these streams into lighter components or treat them to improve their quality, for example, by removing sulfur and nitrogen, improving octane or cetane, or making other changes to enable maximum production of the most valuable products. In this analysis, the objective of each case is to maximize the production of salable transportation fuels, a typical goal for many US refiners.

The refinery considered in this study is assumed to be located in PADD 2. When processing bitumen, naphtha diluent was used to move the bitumen from Canada to the PADD 2 refinery. The bitumen case returned the diluent via pipeline back to Canada, while the diluted bitumen (dilbit) case processed the naphtha diluent with the bitumen to produce final products.

The major products are gasoline for oxygenate blending and ultra-low sulfur diesel. Product specs are shown in Table 5-1. Two grades of gasoline are produced: CBOB (Conventional Blendstock for Oxygenate Blending) and RBOB (Reformulated Blendstock for Oxygenate Blending). The difference between these products is the RVP limit, which is 9 psi for CBOB and 6 psi for RBOB. The quantity of RBOB produced is set at 35,000 BPD for all cases. The quantity of CBOB can vary.

Table 5-1.
Product Specs for Gasoline and Diesel Fuel

Gasoline		Blends	
		CBOB	RBOB
Constraints			
Specific Gravity Min		0.700	0.700
Specific Gravity Max		0.785	0.785
MON Min		81.0	81.0
RVP Max, psi	psi	9.0	6.0
Benzene Max	vol%	0.62	0.62
Sulfur Max	ppm	15	15

Diesel		
Cetane min		40
Sulfur max	ppm	12

A schematic of the refinery is shown in Figure 5-1. The process units are fully described below.

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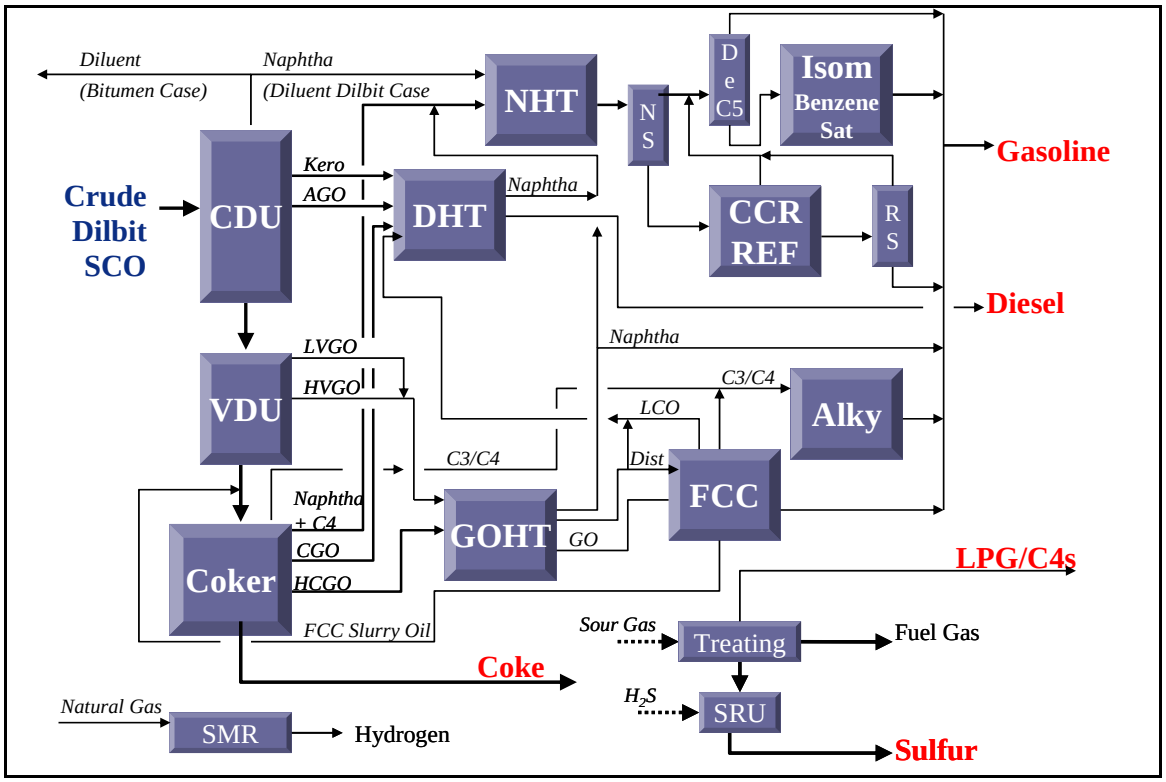
Figure 5-1.
Coking—FCC-based Refinery



- CDU—The crude distillation unit (CDU) fractionates the crude, SCO or dilbit (diluted bitumen) feed into straight run naphtha, kerosene, distillate and heavy atmospheric resid. The crude distillation unit (CDU) is a single column with a one or two-stage preflash and a desalter. Fuel gas, C3s and C4s are sent to the gas plant. Naphtha is sent to the naphtha hydrotreating unit (NHT). Kerosene and atmospheric gas oil go to the DHT (Distillate Hydrotreating Unit). The CDU atmospheric residue bottoms (AR) is sent to the vacuum distillation unit (VDU) for further gas oil recovery. The AGO cut point was set to generate a distillate stream that will produce a 650˚F (343˚C) end point in the diesel hydrotreater product stream.

- VDU—The vacuum distillation unit (VDU) produces vacuum resid, which is sent to a delayed coking unit, and light and heavy vacuum gas oils which are sent to the Gas Oil Hydrotreating Unit (GOHT). The CDU and VDU are heat integrated.

- Delayed Coking Unit—The coking unit converts vacuum resid from the VDU into lighter components, fuel gas, C3 and C4 paraffins and olefins, naphtha, distillate, and gas oils. The delayed coker consists of several coke drums that feed a common fractionator. Fuel

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gas, C3s and C4s go to the Gas Plant. Naphtha from the coker is routed to the NHT. The light coker gas oil (LCGO) from the coker is low in cetane number and high in sulfur and requires processing in the distillate hydrotreater. The heavy coker gas oil (HCGO) is further processed in the GOHT to achieve the sulfur target. Coke from the delayed coker is routed to sales.

- GOHT—The gas oil hydrotreating unit (GOHT) desulfurizes heavy gas oil from the CDU, VDU, and coking units. The level of desulfurization is set so that the feed to the FCC contains less than 1000 ppm sulfur to avoid an FCC naphtha hydrotreating unit. Some of the distillate from the GOHT is included in the feed to the FCC unit to maximize gasoline production. The GOHT is a significant user of hydrogen.

- FCC—The FCC unit converts heavy hydrotreated gas oil to lighter products. About half of the distillate from the GOHT sent to the FCC unit is cracked to lighter products. The rest ends up in the light cycle oil (LCO), which is sent to the DHT. FCC naphtha is sent to gasoline blending. In this analysis, the unconverted oil from the FCC unit (called *slurry oil*) is recycled to the coking unit to avoid producing fuel oil. The FCC unit consists of a reactor / regenerator, a main fractionator, and a wet gas compressor. Flue gas treating with a third stage separator is included to meet emission specifications.

- Alkylation—The sulfuric acid alkylation unit reacts C3 and C4 olefins with isobutane to produce alkylate for gasoline blending. Purchased isobutane supplements that produced in the refinery.

- Naphtha Hydrotreating—Naphtha from the CDU, coker, DHT, and GOHT units are hydrotreated in the NHT and then fractionated to send the C6/C7+ components to the catalytic reforming unit and the C5/C6 components to the isomerization unit. The cut-point between light and heavy naphtha is set to minimize benzene and its precursors in the feed to the catalytic reforming unit. Depending on the feed and degree of desulfurization, the NHT is a low to moderate user of hydrogen.

- CCR Reforming Unit—The catalytic reforming unit is assumed to be a Continuous Catalyst Regeneration Reforming unit (CCR) operating at 90 psig. Reformer severity is adjusted to meet the gasoline octane specification. To meet the 0.62 vol% benzene limit imposed by the Mobile Source Air Toxic (MSAT2) regulations that go into effect for all US gasoline in 2011, the reformate product from the CCR unit is fractionated in a reformate splitter producing light and heavy reformate. Light reformate containing most of the benzene is processed together with the light straight run naphtha from the naphtha splitter in the C5/C6 isomerization unit. The CCR unit is an important source of hydrogen.

- C5/C6 Isom—The isomerization unit is a once-through unit that processes light naphtha and light reformate to increase their research octane from the mid-70s to the low-80s

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and eliminate benzene. If the feed to the isomerization unit exceeds 5 vol% benzene, a separate benzene saturation reactor is used ahead of the isomerization reactor. The isomerization unit uses a small amount of hydrogen to isomerize the C5-C6 paraffins. Three moles of hydrogen per mole of benzene are used to convert benzene to cyclohexane. A depentanizer is used ahead of the isom unit to minimize the RVP impact of isomerization.

- Benzene Saturation—An alternative to eliminating benzene in an isomerization unit is to simply saturate it in a benzene saturation unit. Because there is no isomerization of C5/C6 paraffins that helps offset the octane loss from benzene saturation, it is necessary to operate the CCR Reforming unit at higher severity than when an isom unit is used. The net effect is less overall gasoline yield but more hydrogen from the CCR unit as a result of operating at higher severity. Because of lower net gasoline yield, the benzene saturation option was not chosen.

- DHT—The Distillate Hydrotreating Unit (DHT) reduces sulfur in the distillate range material (kerosene and distillate) from the CDU, coker, and GOHT units, and LCO from the FCC unit to meet ultra-low sulfur diesel (ULSD) specifications. Distillate sulfur is targeted to be less than 12 ppm to meet the 15 ppm limit on diesel when it is sold at the pump. The DHT unit is a significant user of hydrogen.

- Hydrogen—Hydrogen is produced in the CCR unit and in the hydrogen plant, which converts natural gas to hydrogen via steam methane reforming. Process heat to the hydrogen plant is supplied by fuel gas which is supplemented by natural gas if needed. The hydrogen plant includes a pressure swing adsorption unit (PSA) to achieve 99%+ purity.

- Sulfur Plant—Sulfur is recovered in the sulfur plant from H_2S that is produced during the refining steps. The sulfur plant consists of a Claus unit, Tail Gas Treating Plant, Amine Regeneration, and Sour Water stripper.

- Gas Plants—Both saturated and unsaturated gas plants are included in this configuration. These plants are designed to achieve high recoveries of C3s and C4s. Recoveries are assumed to be 92% for C3s and 98% for C4s. Process units include a Primary Absorber, Stripper, Debutanizer, and Amine Treating.

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Refinery Modeling

In this analysis, modeling of refining is done using PetroPlan, a software system supplied by AMI Consultants. By performing block-by-block calculations, all streams (crude oils, intermediate products and blended products) flowing between process blocks are calculated and managed. Each block uses a set of nonlinear equations to predict yields, product properties, and utility consumption. PetroPlan's customization features were used to accurately represent all feedstocks, products, and technologies evaluated in the study. Individual process unit representations were developed using data and models for yields, utilities, *etc*. developed by Jacobs Consultancy as well as input from licensors and other parties where available and appropriate.

A number of crudes were analyzed in this study. Each was modeled individually in PetroPlan to show the impact that it has on product yield, energy use, and GHG emissions from refining.

Alternative approaches to understanding the impact of crudes on energy and yield from refining may examine processing a mixture of crudes. In these approaches, the rate of one crude may be increased by a small amount; the change in energy, yield or economic benefit from this change is assigned to the incremental change in this crude. This approach, often used in refinery economic optimization, is valid over a small change in crude rate. Because the model operates in an economic optimization mode, there may be a number of subtle changes in processing, including crude and intermediate cut-point changes that occur unless the model is constrained. These changes may make it difficult to compare GHG emissions on a life cycle basis for one crude versus another.

The crude-by-crude analysis used in this Study operates in a fixed processing mode and there are no changes in cut-point or processing vectors. To determine the approach's validity, seven crudes were blended and the results compared to the blend of results from processing each individual crude. The good agreement of results from the blend of crudes with results from summing the results from individual crudes gives confidence that the method used in this study is correct. Further discussion on this subject—including results—is provided later in this section.

Figure 5-2 shows an example of the PetroPlan output for refining Arab-Medium crude. The scheme includes a crude and vacuum unit, a delayed coker, a heavy gas oil hydrotreating unit, an FCC unit, an alky unit, CCR reforming unit, and provisions for benzene management, as well as distillate and naphtha hydrotreating. The capacities of each process unit and the severity of operation will depend on the crude properties and desired product volumes and qualities.

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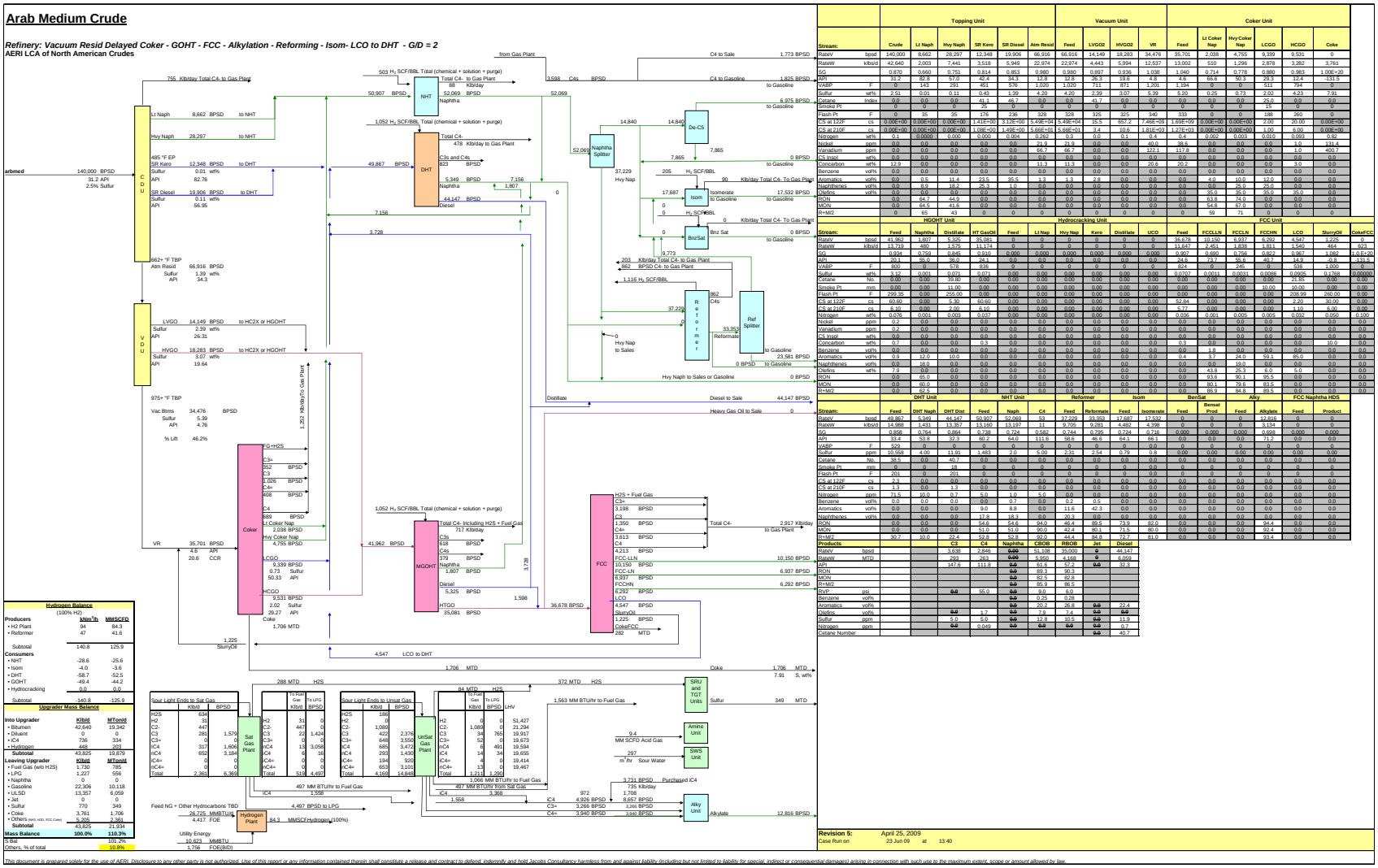
Figure 5-2.
Refining Configuration



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Crudes Examined

Seven conventional crudes were examined in this study. The study also examined the refining of bitumen, dilbit, and two SCOs. In both the bitumen and dilbit cases, bitumen is delivered to the refinery diluted with naphtha diluent. The proportion of naphtha to bitumen is 4 parts diluent to 10 parts bitumen. In the bitumen case, diluent is returned to the production site in Canada. In the dilbit case, diluent is converted to gasoline. One SCO is from a coking-based upgrader and the other from an ebullating bed upgrader. The SCO from the coking-based upgrader is virtually bottomless. The SCO from the ebullating bed upgrader includes the unconverted oil from the ebullating bed unit.

The following crudes were evaluated one by one in the refining model:

- Bachaquero—heavy crude from Venezuela
- Kern River—thermally produced heavy crude from the California Central Valley
- Maya—heavy crude from Mexico
- Arab Medium—medium API crude from Saudi Arabia
- Mars—medium heavy crude from deepwater US Gulf Coast
- Bonny Light—light crude from Nigeria
- Kirkuk Blend—light crude from Iraq near Kirkuk
- SCO—coker-based upgrader
- SCO—ebullating bed-based upgrader
- Athabasca Bitumen—from Alberta Canada—diluent returned
- Dilbit—Athabasca bitumen with diluent—diluent converted to products

Properties of the crudes, bitumens and SCOs are shown in the following table.

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Table 5-2.
Properties of Feeds to the Refinery

Crude Name	API	Sulfur, wt%	Nitrogen, ppm	Micro Carbon Residue or Con Carbon, wt%
Athabasca	8.44	4.81	3,986	12.90
Bachaquero	10.72	2.78	4,599	12.93
Kern River	13.40	1.02	7,177	8.30
Maya	22.08	3.34	3,806	12.60
ArabMed	31.10	2.56	1,442	6.17
Mars	31.48	1.85	1,319	4.79
Bonny Light	32.88	0.16	1,149	1.14
Kirkuk Blend	36.63	1.97	878	4.43
SCO-Ckr Based Upgrader	29.01	0.40	773	0.00
SCO-Eb-Bed Based Upgrader	23.12	0.13	535	4.83

Assay

The following figure shows simplified assays for the crudes, bitumen, and SCOs evaluated in this study. This figure shows the major components in the assay together with the overall crude API, which is related to the density of the crude (API = 141.5/(specific gravity) – 131.5). Note that the assay shown is based on weight percent. Heavier crudes (lower API) contain more resid and less naphtha, distillate and C4-. In the case of SCO from a coking-based upgrader, there is no resid. In this analysis, unconverted oil from the Eb-Bed unit is blended to SCO, hence the assay for this SCO does show some resid.

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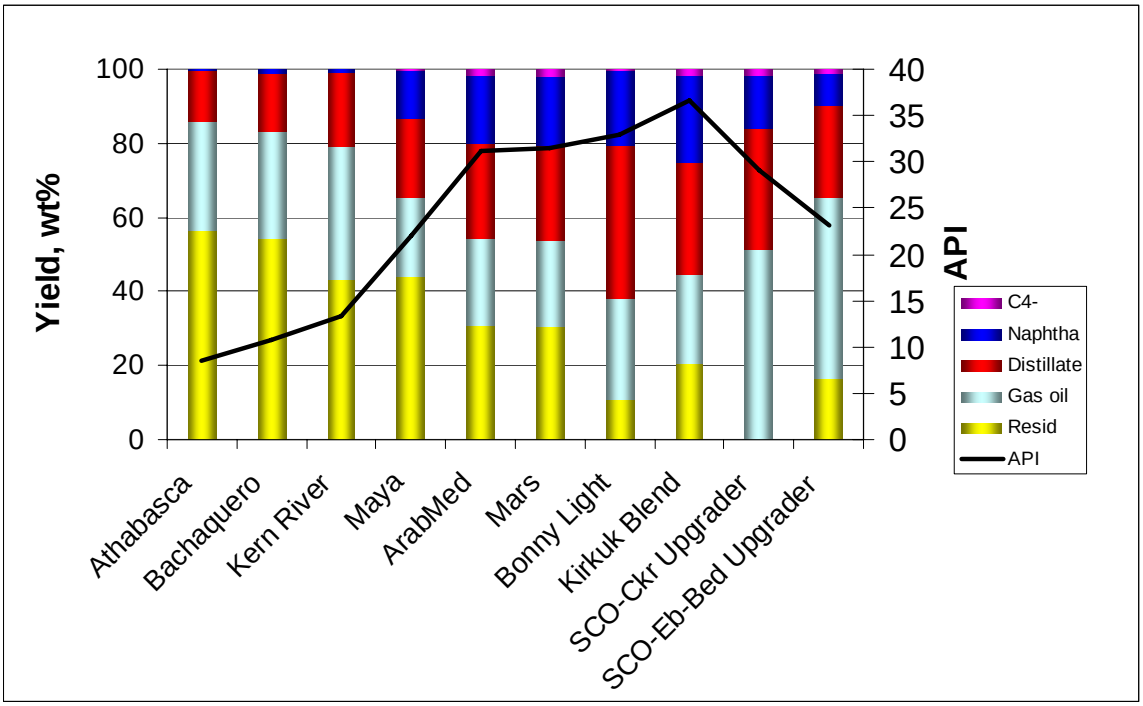
Figure 5-3.
Assay of Feeds to the Refinery



Processing YIelds

Processing capacity is determined by the rate and quality of the feed to the refinery and the product objectives, which are to make gasoline and diesel fuel. Heavy crudes require more processing and hydrogen addition than lighter crudes and will require greater capacity for process units that handle the heavier, higher boiling components, such as atmospheric and vacuum resids and gas oils.

Yield from CDU-VDU

The rate of crude, SCO, bitumen or dilbit to the refinery was set at 140,000 BPD. The CDU-VDU fractionate the feed into components that are further processed in downstream units. Note in the following figure that yields from these units follow the assays. Furthermore, the yields are expressed in pounds per day instead of barrels. Weight was chosen to represent yield so that all the components can be shown. Subsequent processing steps produce H_2S and fuel gas, which are not reported on a volume basis. VR is vacuum resid. In the bitumen processing case, diluent is returned to the production site and the CDU capacity is 196,000 BPD to produce 140,000

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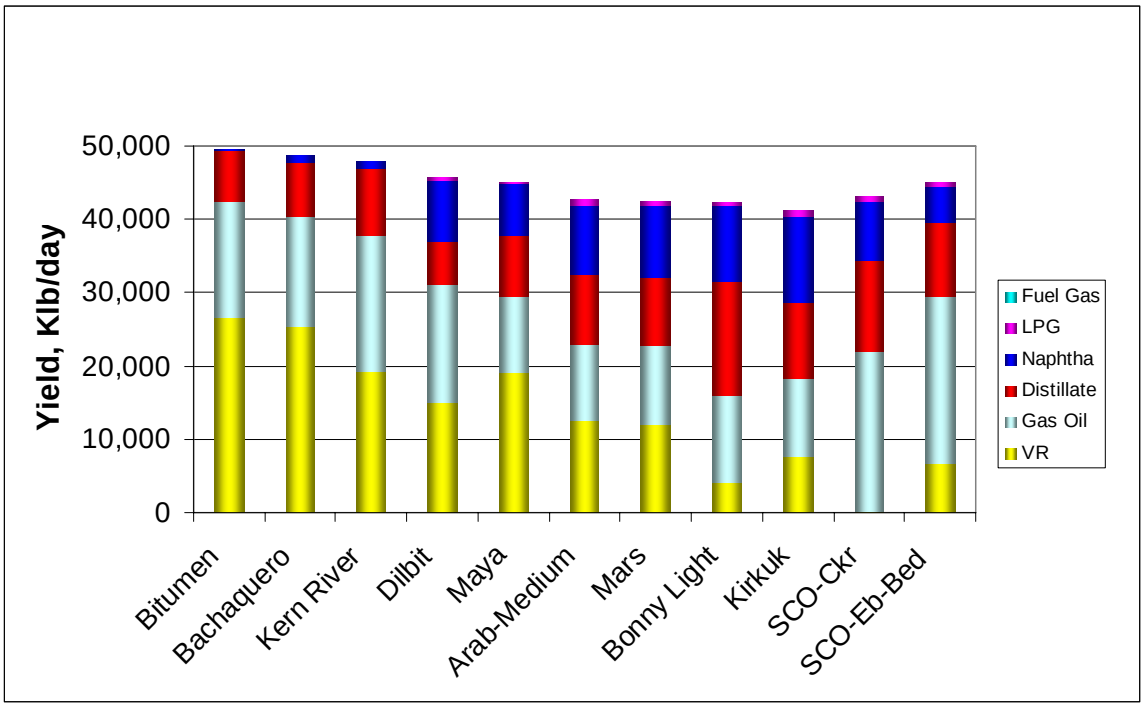
BPD of bitumen. In the Dilbit case, the CDU capacity is 140,000 BPD to process 100,000 BPD of bitumen and 40,000 BPD of naphtha diluent.

Heavier crudes yield more product weight than lighter crudes for the same volume. Also note that heavier crudes yield greater quantities of higher boiling material (such as coke and gas oils) than lighter crudes and will require greater processing intensity to achieve the same yield of gasoline and distillate as lighter crudes.

Figure 5-4.
Weight Yield from CDU-VDU



Yield from CDU-VDU-Coking Units

The next step in conversion is to process the vacuum resid in the coking unit. Yields through coking are shown in the next figure. Note that the yields from the coker include the yield from recycle of slurry oil from the FCC unit. As discussed, slurry oil from the FCC is sent to the Coker to avoid making fuel oil from the refinery. One observation from this figure is that the gap in yield of lighter components between crude oils is closing as a result of adding the coking unit, which cracks vacuum resid to lighter material and rejects refractory material as coke.

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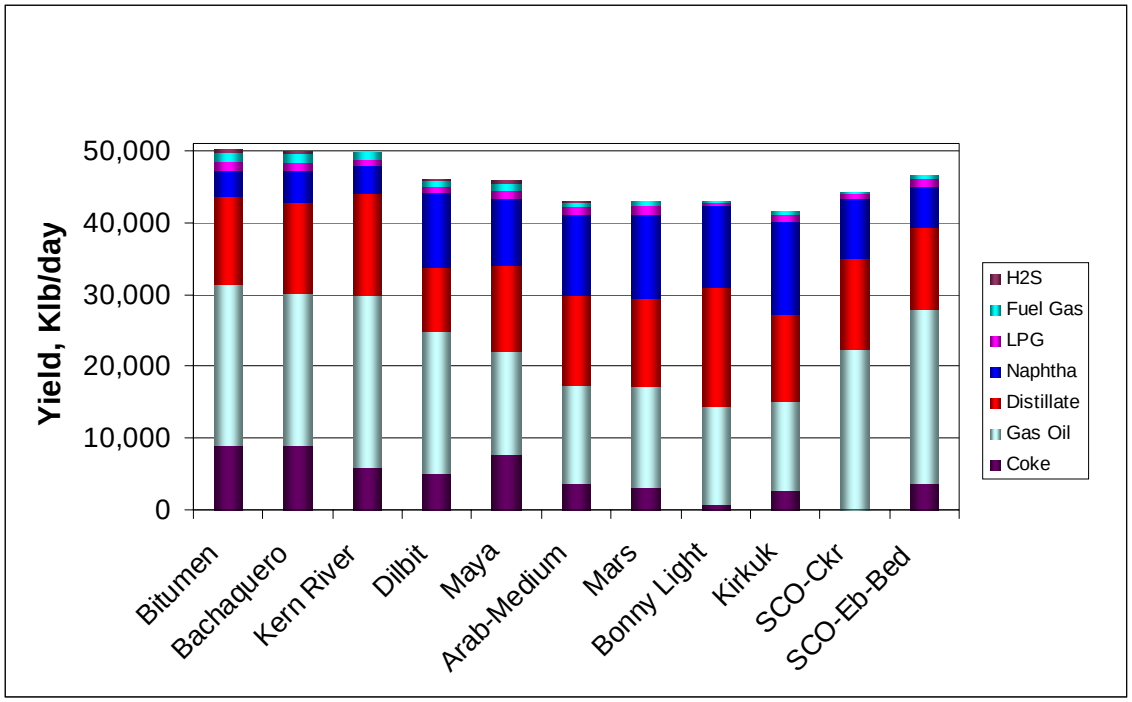
Figure 5-5.
Weight Yield from CDU-VDU-Coking Units



Yield from CDU-VDU-Coking-GOHT-FCC Units

Processing gas oils through the GOHT and FCC unit further reduces the gap in yield of distillate and lighter components between light and heavy crudes. For the results shown in Figure 5-6, fCC coke yields are excluded from the product slate.

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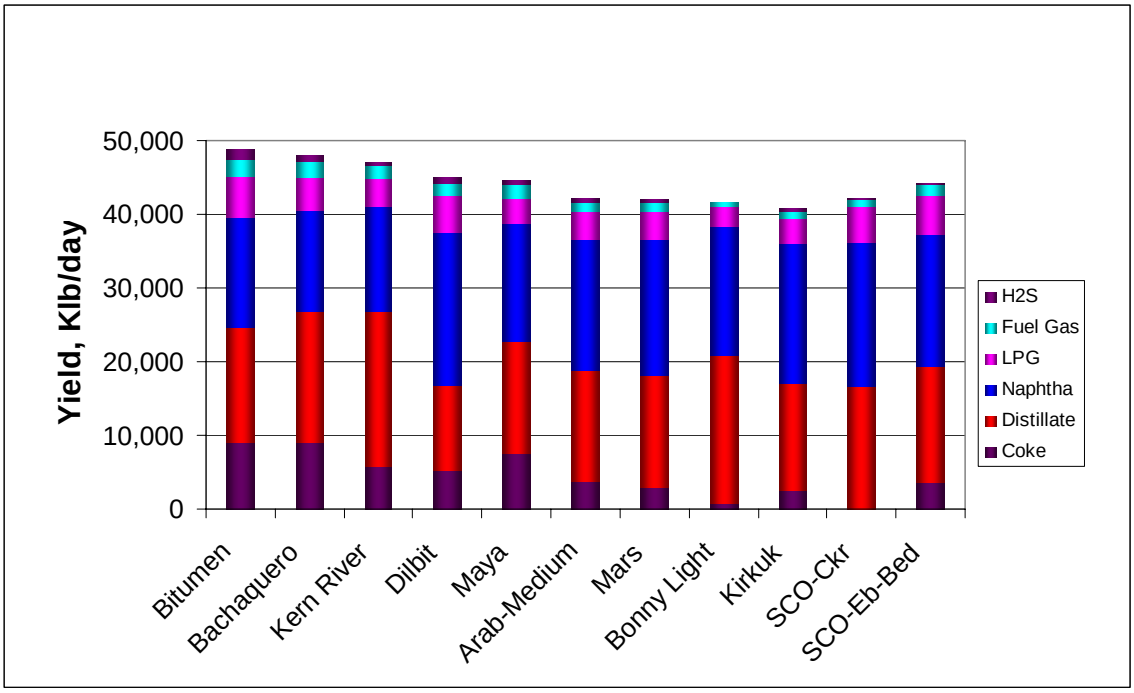
Figure 5-6.
Weight Yield from CDU-VDU-Coking-GOHT and FCC Units



Overall Yield

Subsequent processing steps upgrade the olefins, naphtha and distillate streams from the primary processing units into finished products, which are LPG, C4s, gasoline and diesel. Overall yield of products is shown in the following figure. Fuel gas and FCC coke are used internally as refinery fuel. Fuel gas consists primarily of C1s and C2s and a small amount of C3s and C4s not recovered in the gas plant. FCC coke is burned in the FCC regenerator and provides process heat to the unit. H_2S is converted to sulfur in the sulfur plant. The greater yield shown in Figure 5-7 vs. Figure 5-6 reflects the addition of i-C4 used to convert C3 and C4 olefins to gasoline in the sulfuric acid alkylation unit.

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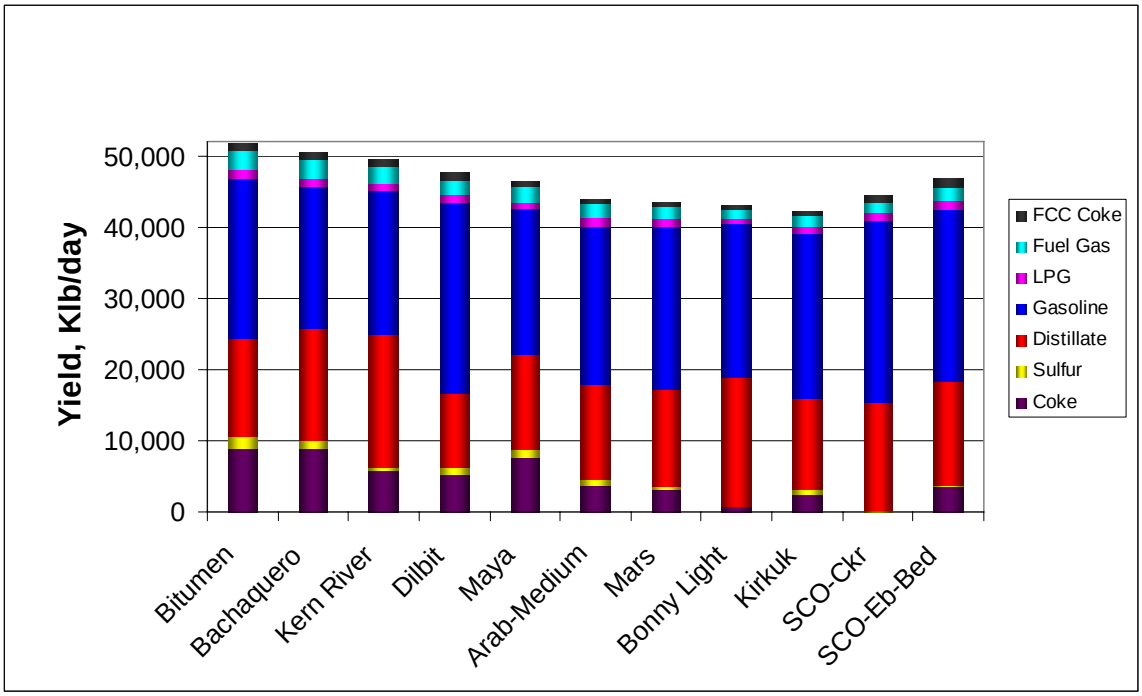
Figure 5-7.
Weight Yield of Products from Refining



To sort out yield of fuel products separately from overall yield, Figure 5-8 shows only the yield of LPG, gasoline and diesel. Yield is highest for lighter feeds and feeds that have little or no coke precursors, such as SCO from the coking and Eb-Bed-based upgraders.

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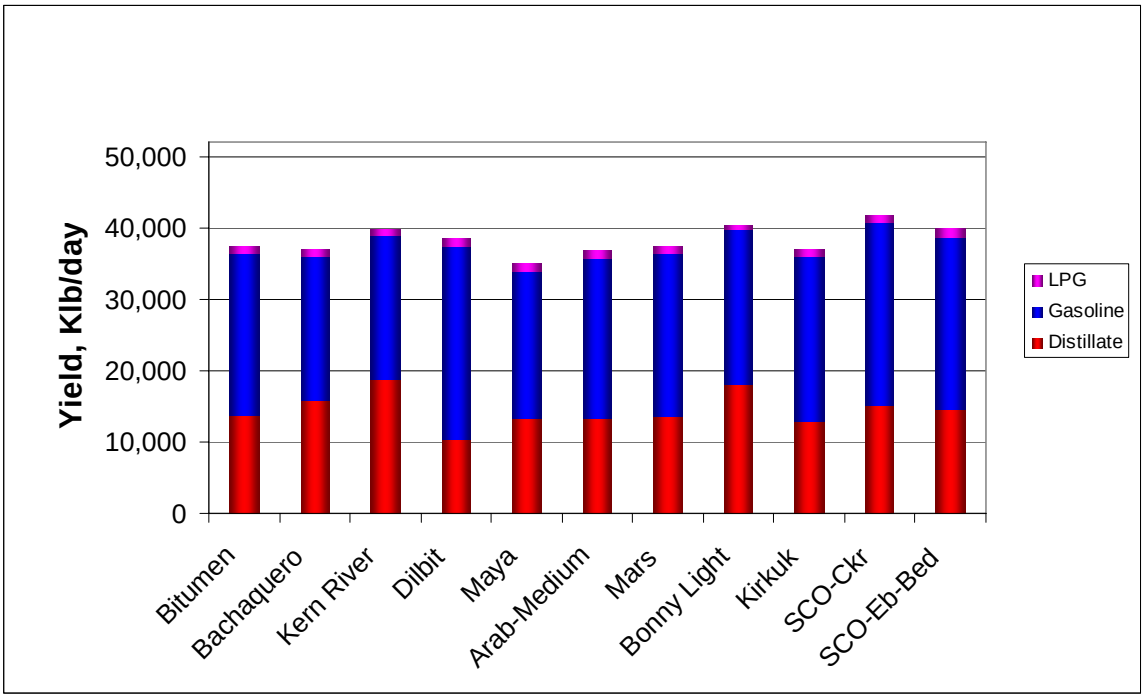
Figure 5-8.
Weight Yield of LPG, Gasoline and Diesel from Refining



The volume yield of major products, LPG, gasoline and diesel is shown in the following figure. Gasoline consists of two products: CBOB (Conventional Blendstock for Oxygenate Blending) and RBOB (Reformulated Blendstock for Oxygenate Blending). Diesel yield depends on crude properties and the extent of conversion. For a fixed feed rate of 140,000 BPD of crude, there is more gasoline produced from the Coking-based SCO than from Eb-Bed-based SCO because the former is virtually bottomless. Gasoline yield is much higher for the Dilbit case than the other cases as a result of converting diluent to gasoline.

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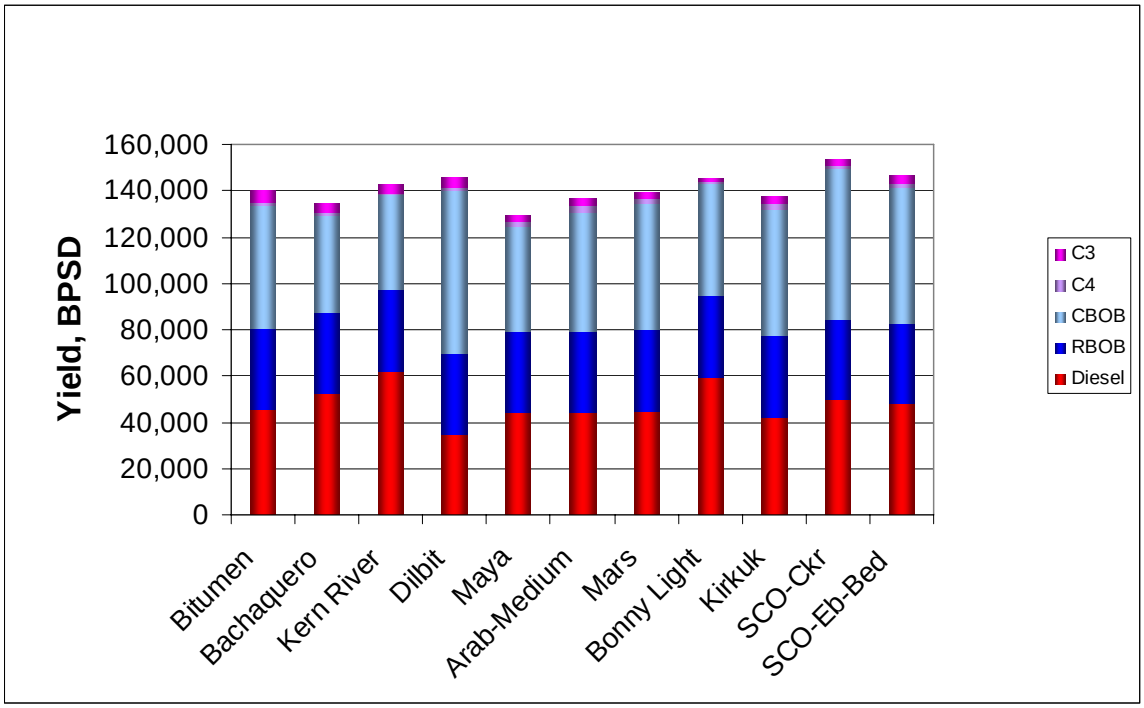
Figure 5-9.
Volume Yield of Products from Refining



The capacities of the major process units are shown in the following table. All rates are in BPSD of feed with the following exceptions. The alky unit capacity is based on alkylate product. Hydrogen capacity is based on MM SCFD of hydrogen. Sulfur plant capacity is based on MTD of sulfur. Capacity was allowed to flex to meet the processing objectives.

Product Yield

Yield of major products is shown in Table 5-4.

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Table 5-3.
Refinery Process Unit Capacity

Crude	Units	Bitumen	Bachaquero	Kern River	Dilbit	Maya	Arab-Medium	Mars	Kirkuk	Bonny Light	SCO-Ckr	SCO-Eb-Bed
Crude API		8.4	10.7	13.4	20.5	22.1	31.2	31.5	36.6	32.9	29.5	22.1
Processing Capacity												
Crude Unit	BPSD	196,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Vacuum Unit	BPSD	118,009	113,119	107,555	86,341	83,109	66,916	67,064	54,714	48,531	65,107	84,948
Coking Unit	BPSD	73,316	71,916	58,620	41,831	53,369	35,701	35,193	22,717	13,733	3,289	21,123
Naphtha Hydrotreater	BPSD	22,774	25,470	25,552	47,189	43,724	50,907	52,048	57,073	51,318	38,477	28,511
Diesel Hydrotreater	BPSD	49,558	56,390	66,115	37,474	49,168	49,867	50,110	48,338	65,324	52,966	50,161
Gas Oil Hydrotreating Unit	BPSD	65,123	62,036	70,547	59,266	43,376	41,962	43,231	38,745	41,192	65,984	71,534
Naphtha Splitter	BPSD	23,409	26,195	26,302	48,218	44,716	52,069	53,256	58,333	52,501	39,343	29,192
Lt Naphtha Depentanizer	BPSD	6,672	7,466	7,496	13,742	12,744	14,840	15,178	16,625	14,963	11,213	8,320
Reformer	BPSD	16,737	18,729	18,806	34,476	31,972	37,229	38,078	41,708	37,538	28,130	20,872
Reformate Splitter	BPSD	14,985	16,766	16,846	30,810	28,642	33,353	34,116	37,365	33,616	25,203	18,691
Isom Unit	BPSD	7,949	8,894	8,934	16,356	15,237	17,687	18,091	19,815	17,909	13,365	9,914
FCC	BPSD	60,073	54,401	62,173	54,940	37,822	36,678	37,908	33,977	36,473	63,271	68,543
Alky	BPSD Alkylate	23,051	17,579	15,665	20,356	12,770	12,816	13,132	11,611	9,911	19,149	20,518
Sulfur Plant	MTD	704	408	170	480	434	349	270	266	27	78	56
H2 Plant (SMR)	MMSCFD	133	122	132	98	83	84	79	71	73	57	60

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Table 5-4.
Products from Refining

	Units	Bitumen	Bachaquero	Kern River	Dilbit	Maya	Arab-Medium	Mars	Kirkuk	Bonny Light	SCO-Ckr	SCO-Eb-Bed
Feed to Refinery												
Crude	BPSD	140,000	140,000	140,000	100,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
API		8.4	10.7	13.4	8.4	22.1	31.2	31.5	36.6	32.9	29.5	22.1
Sulfur	wt%	4.81	2.78	1.02	4.81	3.32	2.51	1.82	1.94	0.15	0.40	0.35
Diluent in Dilbit	BPSD	0	0	0	40,000	0	0	0	0	0	0	0
API					62.4							
i-C4 Purchase	BPSD	8,665	6,275	5,282	7,285	4,225	3,731	2,773	2,865	2,462	5,647	6,323
Products												
C3	BPSD	5,204	4,541	3,988	4,122	3,618	3,638	2,924	2,918	2,033	3,037	3,839
C4	BPSD	1,039	1,221	747	1,401	1,649	2,846	2,709	2,510	1,211	1,851	1,874
CBOB	BPSD	53,183	40,746	40,263	70,688	43,965	51,108	52,892	54,184	46,162	63,159	57,356
RBOB	BPSD	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Diesel	BPSD	45,715	52,478	62,116	34,554	44,034	44,147	44,812	42,468	59,527	49,824	47,795
Coke	Klb/day	8,998	8,983	5,884	5,112	7,696	3,761	3,022	2,597	802	33	3,635
Sulfur	Klb/day	1,552	898	374	1,058	958	770	594	587	59	172	123

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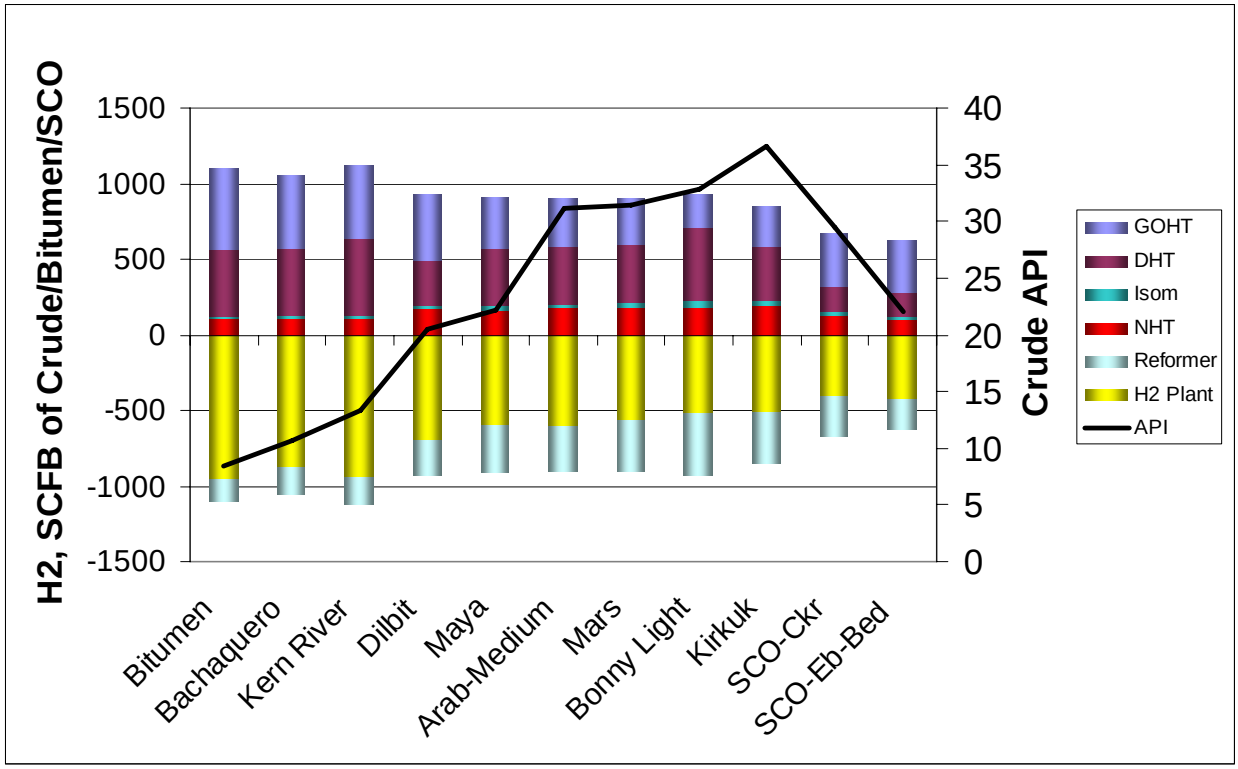
Hydrogen Addition

Hydrogen is used to reduce sulfur and nitrogen in gas oils, distillates and naphtha. It is used to facilitate conversion in the GOHT and cetane improvement in the DHT. Hydrogen is produced by the CCR unit and Hydrogen plant. Overall users and producers are shown in Figure 5-10; users are positive, producers are negative. Heavier crudes require more hydrogen addition. Feeds that have already been extensively hydrotreated (*e.g.,* SCO from the Eb-Bed upgrader) require less hydrogen than other more hydrogen-deficient feeds.

Figure 5-10.
Hydrogen Addition per Bbl of Crude, Bitumen, or SCO Processed



In addition, hydrogen usage correlates with processing intensity, which correlates with crude API, as shown in the following figure. Hydrogen addition does not correlate well with API for Eb-Bed-based SCO because this SCO has been extensively hydroprocessed in the upgrader and also contains unconverted oil.

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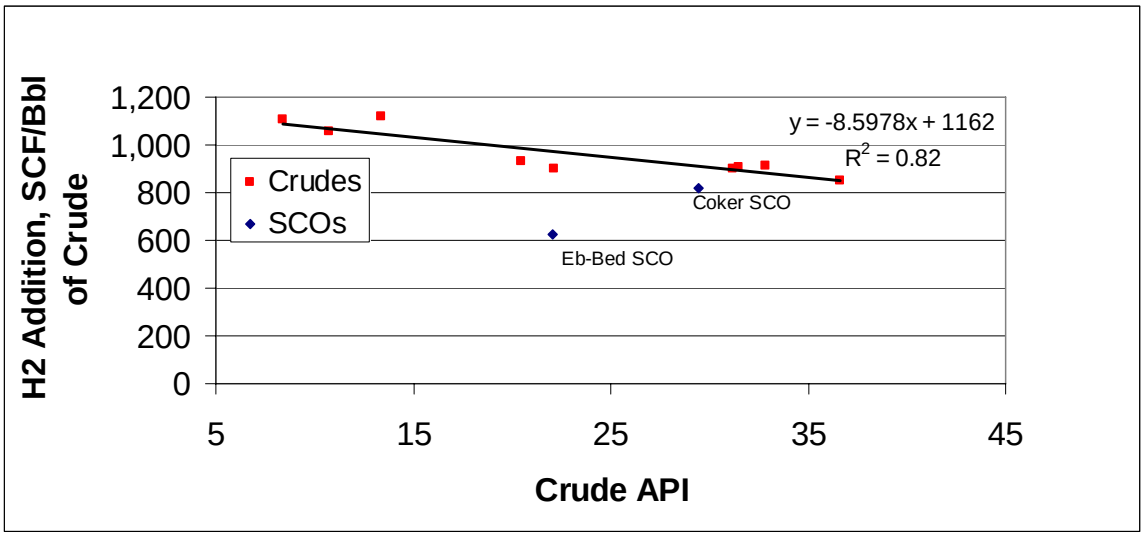
Figure 5-11.
Impact of API on Hydrogen Addition per Bbl of Crude, Bitumen or SCO Processed



Utility Consumption

GHG emissions correlate with energy use and energy use correlates with processing intensity. Utility models were used to estimate the utility consumption for each process unit and the auxiliary units such as the hydrogen plant, sulfur plant, cooling tower, process boilers, *etc*. that are shared between process units. An example of a utility estimate for converting 140,000 BPD of Arab-Medium crude to refined products is shown in Table 5-5. The following utilities are consumed:

- Electric Power—imported
- Natural Gas—imported
- Fuel Gas—generated in the refinery
- FCC Coke—generated in the refinery
- Steam—generated in the refinery
- Boiler Feed Water—generated in the refinery
- Condensate—generated in the refinery
- Cooling Water—generated in the refinery

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Table 5-5.
Utility Balance for Refining Arab-Medium Crude

Utility Summary								Fuel Consumed		
Process Unit	**Capacity**	**Units**	**Hydrogem** Klb/hr	**Electric Power KW**	**Steam** k#/hr	**Boiler** Feed Water k#/hr	**Cooling Water** GPM	**Refinery Fuel Gas** MMBTU/hr	**Natural Gas** MMBTU/h	**FCC Coke** MMBTU/h
Upgrader										
Crude Unit	140,000	BSD Chg.	0.0	-4,492	-37	0	-387	-204	0	0
Vacuum Unit	66,916	BSD Chg.	0.0	-1,060	-29	0	-3,943	-103	0	0
Coking Unit	35,701	BSD Chg.	0.0	-3,124	25	-77	-2,301	-195	0	0
Gas Oil Hydrotreating Unit	41,962	BPSD	-234.9	-12,152	20	-81	-108	-61	0	0
Other Process Units		BPSD	-213.3	-55,477	-492	-505	-43,048	-721	-24	-415
Sulfur Recovery										
Sulfur Plant	349	MT/d	0	-1,456	95	-97	0	0	0	0
Amine Regen	9	MM SCFD AG	0	-1,180	-98	0	-1,500	0	0	0
SW Stripper	654	MLB/h	0	-194	-61	0	-63	0	0	0
Utilities										
H2 Plant (SMR)	84	MMSCFD	448.2	-2,630	73	-174	-621	-443	-1,114	0
Dearators	1,574	Klb BFW	0	-1,480	-130	1574	0	0	0	0
Demin Plant	1,216	Klb/h	0	0	0	0	0	0	0	0
Cooling Towers	51,970	gpm	0	-1,299	0	0	51,970	0	0	0
Process Boilers	634	Klb/h	0	0	634	-641	0	-746	0	0
Direct + Indirect Utilities										
Total Direct			-448.2	-79,134	-578	-760	-51,350	-1,284	-24	-415
Total Indirect			448.2	-5,410	578	760	51,350	-1,189	-1,114	0
TOTALS			**0.0**	**-84,544**	**0**	**0**	**0**	**-2,473**	**-1,138**	**-415**

Net Fuel Gas deficit	-910	MM BTU/hr
Natural Gas Import	-2048	MM BTU/hr
Net Natural Gas Usage		
For H2 Plant	-1114	MM BTU/hr
For Miscellaneous	-24	MM BTU/hr
For Gas Turbine	0	MM BTU/hr
To Balance Fuel Gas needs	-910	MM BTU/hr

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Fuel gas is used for process heat to the refinery processing units and the hydrogen plant. Natural gas supplements fuel gas where needed and is used as process feed to the hydrogen plant. A small amount of natural gas is used for pilot lights in heaters and the flare; there are a few other small users of natural gas. FCC coke is burned to provide process heat for the FCC unit. These utilities consumed in each process unit are called *direct utilities*.

Indirect utilities are used in the utility plants—such as the cooling tower, boilers, water deaerator, and hydrogen plants—which generate utilities used by other plants and also consume utilities such as power, fuel gas, electricity, water, *etc*.

In life cycle analysis it is important that the energy used in making each product be properly distributed to that product for it to bear the appropriate GHG emissions burden. This means distributing direct utilities consumed in each process unit plus indirect utilities to the products. In addition, it is important to distribute any upstream energy or GHG burden brought in with the feeds to the refinery and utilities brought into the refinery, such as natural gas or power. Distributing feeds and utilities brought into the refinery to the products allows the upstream burden for producing these feeds and utilities to be added later. This is especially important because the upstream burden for crudes varies widely.

Distributing energy and upstream burden is done using the lower heating value (LHV) of the products. Heating value is calculated using an API method more fully described in Appendix B.

In this analysis, utility burden is assigned to streams that become products and not to streams that are used as internal fuels (fuel gas and FCC coke) or to H_2S. Thus, all C2- material is excluded from carrying any utility burden. However, C3s and C4s that end up in products—including C3s and C4s that go to the alky unit—will carry utility burden; C3 and C4 olefins that end up in fuel gas carry no burden.

Distribution of Utilities and Feed Content to Products

An example showing the distribution of feed, crude, electric power and hydrogen to the products from the CDU, VDU, Coker, and GOHT is shown in Table 5-6. This table also shows how crude and hydrogen are distributed into the products. The methodology for distributing other feeds (*e.g.,* isobutane or diluent from dilbit) into products is the same.

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Table 5-6.
Distribution of Feed, Hydrogen, Power to Products for CDU, VDU, Coker and GOHT – Arab Medium Crude

CDU

		IN						OUT									CHECK		
	Units	Crude			Mixed Feed	Add for Processing	For Distribution	C4- FG	C4- Alky	C4-LPG	LSR	HSR	Kero	SRDiesel	AR		In	Out	Error
RateW	Klb/day	42,640			42,640		42,640	55	111	589	2,003	7,441	3,518	5,949	22,974		42,640	42,640	0.0%
LHV	BTU/lb	17,916						20,607	19,658	19,678	18,210	18,585	18,431	18,146	17,122				0.0%
Net Heating Value	MMBTU/day	763,926			763,926		763,926	636	2,188	11,589	36,479	138,280	64,841	107,954	393,370		763,926	755,336	-1.1%
Crude Disposition to Products	wt%	100.0%			100.0%		100.0%	0.0%	0.3%	1.5%	4.8%	18.3%	8.6%	14.3%	52.1%		100.0%	100.0%	0.0%
Hydrogen	Klb/day	0.0			0.0		0.0	0	0	0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0%
Power	KW				0	-4,492	-4,492	0	-13	-69	-217	-823	-386	-642	-2,341		-4,492	-4,492	0.0%
Steam	Klb/hr				0	-37	-37	0	0	-1	-2	-7	-3	-5	-19		-37	-37	0.0%
BFW	k#/hr				0	0	0	0	0	0	0	0	0	0	0		0	0	0.0%
Cool Water	GPM				0	-387	-387	0	-1	-6	-19	-71	-33	-55	-202		-387	-387	0.0%
Fuel Gas Consumed	MMBTU/hr				0	-204	-204	0	-1	-3	-10	-37	-18	-29	-106		-204	-204	0.0%
FCC Coke	MM BTU/h				0	0	0	0	0	0	0	0	0	0	0		0	0	0.0%

VDU

	Units	AR			Mixed Feed	Add for Processing	For Distribution	C4- FG	C4- Alky	C4-LPG	LVGO2	HVGO2	VR				In	Out	Error
RateW	Klb/day	22,974			22,974		22,974	0	0	0	4,443	5,994	12,537				22,974	22,974	0.0%
LHV	BTU/lb	17,122						0	0	0	17,807	17,511	16,652						0.0%
Net Heating Value	MMBTU/day	393,370			393,370		393,370	0	0	0	79,113	104,971	208,775				393,370	392,858	-0.1%
Crude Disposition to Products	wt%	52.1%			52.1%		52.1%	0.0%	0.0%	0.0%	10.5%	13.9%	27.7%				52.1%	52.1%	0.0%
Hydrogen	Klb/day	0			0.0		0.0	0	0	0	0.0	0.0	0.0				0.0	0.0	0.0%
Power	KW	-2,341			-2,341	-1,060	-3,401	0	0	0	-685	-909	-1,807				-3,401	-3,401	0.0%
Steam	Klb/hr	-19			-19	-29	-49	0	0	0	-10	-13	-26				-49	-49	0.0%
BFW	k#/hr	0			0	0	0	0	0	0	0	0	0				0	0	0.0%
Cool Water	GPM	-202			-202	-3,943	-4,144	0	0	0	-835	-1,107	-2,202				-4,144	-4,144	0.0%
Fuel Gas Consumed	MMBTU/hr	-106			-106	-103	-210	0	0	0	-42	-56	-111				-210	-210	0.0%
FCC Coke	MM BTU/h	0			0	0	0	0	0	0	0	0	0				0	0	0.0%

Delayed Coker

	Units	VR	FCC Slurry Oil		Mixed Feed	Add for Processing	For Distribution	C4- FG	C4- Alky	C4-LPG	CokerLN	CokerHN	LCGO	HCGO	Coke	NH3	In	Out	Error
RateW	Klb/day	12,537	464		13,001		13,001	804	355	92	510	1,296	2,878	3,282	3,761	23	13,001	12,979	-0.2%
LHV	BTU/lb	16,652	17,081				0	21,236	19,683	19,800	18,511	18,472	17,937	16,000	10,491	7,155			0.0%
Net Heating Value	MMBTU/day	208,775	7,931		216,706		216,706	13,958	6,993	1,826	9,437	23,936	51,630	52,511	39,458	0	216,706	199,750	-7.8%
Crude Disposition to Products	wt%	27.7%	1.2%		28.9%		28.9%	0.0%	1.1%	0.3%	1.5%	3.7%	8.0%	8.2%	6.1%	0.0%	28.9%	28.9%	0.0%
Hydrogen	Klb/day	0.0	-8.4		-8.4		-8.4	0	0	0	-0.4	-1.1	-2.3	-2.4	-1.8	0.0	-8.4	-8.4	0.0%
Power	KW	-1,807	-703		-2,511	-3,124	-5,634	0	-212	-55	-286	-726	-1,566	-1,592	-1,197	0	-5,634	-5,634	0.0%
Steam	Klb/hr	-26	0		-26	25	0	0	0	0	0	0	0	0	0	0	0	0	0.0%
BFW	k#/hr	0	-14		-14	-77	-91	0	-3	-1	-5	-12	-25	-26	-19	0	-91	-91	0.0%
Cool Water	GPM	-2,202	-381		-2,584	-2,301	-4,885	0	-184	-48	-248	-629	-1,357	-1,381	-1,037	0	-4,885	-4,885	0.0%
Fuel Gas Consumed	MMBTU/hr	-111	-14		-126	-195	-321	0	-12	-3	-16	-41	-89	-91	-68	0	-321	-321	0.0%
FCC Coke	MM BTU/h	0	-17		-17	0	-17	0	-1	0	-1	-2	-5	-5	-4	0	-17	-17	0.0%

GOHT

	Units	LVGO2	HVGO2	HCGO	Mixed Feed	Add for Processing	For Distribution	C4- FG	C4- Alky	C4-LPG	Nap-GOHT	Dsl-GOHT	GO-GOHT	NH3c			In	Out	Error
RateW	Klb/day	4,443	5,994	3,282	13,719		13,719	555	46	129	480	1,575	11,173	8			13,954	13,966	0.1%
LHV	BTU/lb	17,807	17,511	16,000				24,442	19,666	19,841	18,599	18,379	18,065	7,155					0.0%
Net Heating Value	MMBTU/day	79,113	104,971	52,511	236,595		236,595	5,349	902	2,567	8,931	28,956	201,837	0			236,595	248,542	5.0%
Crude Disposition to Products	wt%	10.5%	13.9%	8.2%	32.6%		32.6%	0.0%	0.1%	0.3%	1.2%	3.9%	27.0%	0.0%			32.6%	32.6%	0.0%
Hydrogen	Klb/day	0.0	0.0	-2.4	-2.4	-234.9	-237.3	0	-1	-3	-8.7	-28.3	-196.9	0.0			-237.3	-237.3	0.0%
Power	KW	-685	-909	-1,592	-3,186	-12,152	-15,338	0	-57	-162	-563	-1,826	-12,729	0			-15,338	-15,338	0.0%
Steam	Klb/hr	-10	-13	0	-23	20	-3	0	0	0	0	0	-3	0			-3	-3	0.0%
BFW	k#/hr	0	0	-26	-26	-81	-107	0	0	-1	-4	-13	-89	0			-107	-107	0.0%
Cool Water	GPM	-835	-1,107	-1,381	-3,323	-108	-3,431	0	-13	-36	-126	-408	-2,847	0			-3,431	-3,431	0.0%
Fuel Gas Consumed	MMBTU/hr	-42	-56	-91	-189	-61	-250	0	-1	-3	-9	-30	-207	0			-250	-250	0.0%
FCC Coke	MM BTU/h	0	0	-5	-5	0	-5	0	0	0	0	-1	-4	0			-5	-5	0.0%

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Starting with the crude unit, the utilities needed to fractionate the crude are distributed onto the products by prorating based on net heating value of the products, which is determined from the weight of each product and its LHV.

- Disposition of C4- to fuel gas, alkylation and LPG shown in Table 5-6 is a simplification. In the refinery model used in this analysis, the components that are tracked are C2-, propane, propylene, n-butane, i-butane, i-butene, and n-butene.
- Products from the crude unit are sent on to the next processing unit. In this example, atmospheric resid and its utility burden go to the VDU. The utility burden brought in with the feed and the utilities needed to operate the VDU are distributed to the products using net heating value of the products to prorate the utilities.
- Next, the VR from the VDU is sent to the delayed coker. Here it is joined with the FCC slurry oil that is recycled from the FCC unit to the coker because one of the refining objectives in this study is to not make fuel oil. The sum of utilities brought in with the VR and the FCC slurry oil plus the utilities used in the coker are distributed to the coking unit products, again using net heating value to prorate the utilities.
- Feeds to the GOHT consist of LVGO and HVGO from the VDU and HCGO from the coker. Hydrogen used in the GOHT is distributed to the products in the same manner as the other utilities.
- Table 5-7 shows the yield of products, C3 LPG, C4, CBOB, RBOB, diesel, Coke and sulfur from refining 140,000 BPD of Arab-Medium. Table 5-7 also shows the distribution of crude, iC4 used in alkylation, and H_2 to each product, as well as the distribution of direct utilities consumed in the process units to the refinery products. These utilities include boiler feed water, cooling water, steam, natural gas, FCC coke, *etc*. A comparison of the results in Table 5-7 with the direct utilities in Table 5-5 shows good agreement in distributing direct utilities to the products.
- Comparison of the results in Table 5-7 with those in Table 5-5 shows that the indirect utilities associated with the utility plants still need to be distributed. In addition, the utilities are expressed in terms of how they are used in the refinery, steam in klb/hr, cooling water in gpm, and not in primary energy units, such as MMBtu/hr of natural gas or fuel gas and kW of electric power.
- Translation of steam, cooling water, boiler feed water etc into primary units of energy uses the methodology in Figure 5-12

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Table 5-7.
Distribution of Direct Utilities to Products – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
RateV	BPSD	3,487	2,759	51,697	35,000	44,149	0	0	
RateW	Klb/day	619.6	561.8	13,292.6	9,120.9	13,358.0	3,761.1	770.5	41,485
API		146.66	111.81	61.37	58.80	32.28	-131.50	-131.50	
Corrected NHV	BTU/lb	19,917	19,594	18,590	18,599	18,298	16,000	3,983	
Net Heating Value Associated with Stream (Eng Units)	MMBTU/day	12,341	11,008	247,109	169,641	244,423	60,177	3,069	
Diluent Disposition to Products	wt%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Crude Disposition to Products	wt%	1.63%	1.46%	34.06%	23.20%	33.52%	6.13%	0.00%	100%
Purchased Isobutane	wt%	0.00%	0.00%	43.71%	56.29%	0.00%	0.00%	0.00%	100%
Hydrogen	Klb/day	-7.5	-3.5	-93.5	-57.3	-294.2	-1.8	0.0	-457.8
Total Utilities Before Adding Indirect Utilities									
Power	KW	-819	-670	-29,902	-21,517	-21,508	-1,873	-2,866	-79,155
Steam	Klb/hr	-11	-7	-202	-164	-126	-5	-65	-580
Fuel Gas	MM BTU/hr	-16	-13	-537	-399	-250	-69	0	-1,285
Natural Gas as Fuel	MM BTU/hr	0	0	-8	-6	-8	-2	0	-25
Natural Gas Used as Process Feed to H2 Plant	MM BTU/hr	0	0	0	0	0	0	0	0
FCC Coke	MM BTU/h	-11	-5	-198	-140	-57	-4	0	-415
Cooling Water	GPM	-1,827	-962	-20,204	-18,574	-6,871	-1,355	-1,579	-51,372
BFW	Klb/hr	-10	-6	-324	-230	-74	-19	-97	-760

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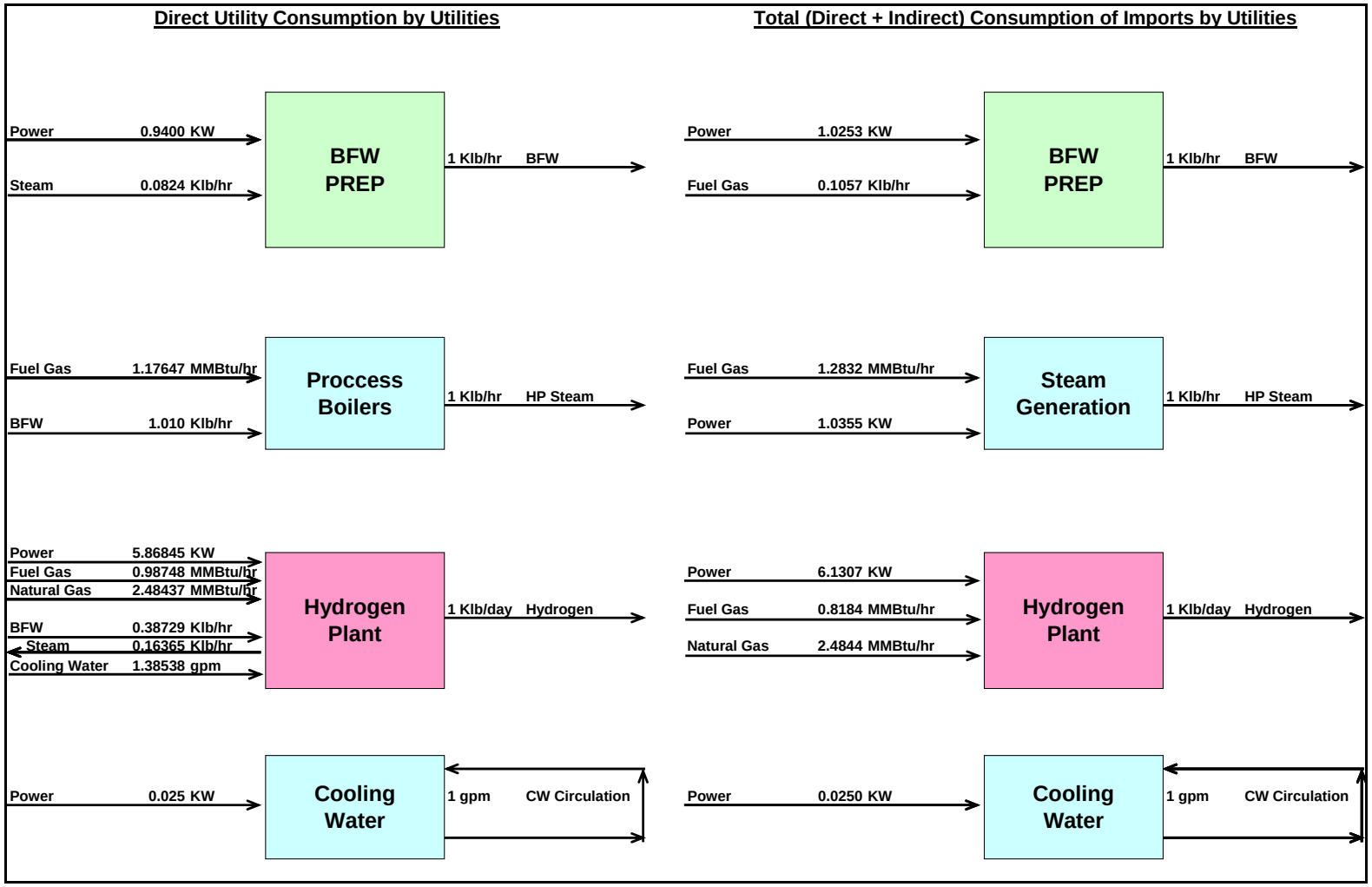
Figure 5-12.
Translation of Utilities to Primary Energy



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- The utility plants on the left side of the figure show the energy needed to produce one unit of utility. For example, the deaerator (BFW), which produces boiler feed water, uses 0.94 kW of electricity and 0.0824 klb/hr of steam to generate 1 klb/hr of boiler feed water. These numbers can be calculated from the rates and the values shown in Table 5-5. Thus, the deaerator uses 1484 kW of electricity to produce 1578 klb/hr of boiler feed water, which translates to 0.94 kW/(klb/hr).

- Likewise, the hydrogen plant uses power, fuel gas, natural gas, boiler feed water, and cooling water to generate hydrogen. However, this plant also generates steam.

- Translating these utilities into primary units of natural gas, fuel gas and electric power requires recognizing that the utility plants are interdependent. Thus, the deaerator (BFW) uses steam produced in the process boilers to generate boiler feed water. But the process boiler uses boiler feed water from the deaerator. The BFW on the right side of Figure 5-12 shows power used directly plus the power to make the steam used in deaeration, which includes the component for making boiler feed water. In a similar manner, the fuel gas shown on the right side of Figure 5-12 for the BFW is higher than the fuel gas on the left side of Figure 5-12 because it includes the fuel gas used in the process boilers to make steam.

- The distribution of hydrogen, cooling water, boiler feed water and steam to the products is shown in Table 5-8. These utilities require electric power, fuel gas and natural gas to generate them. Translation of the hydrogen, steam, boiler feed water, and cooling water assigned to the products to fundamental units of energy using the factors in Figure 5-12 results in the breakdown shown in Table 5-8, where the energy to generate boiler feed water is shown as electric power and fuel gas.

- The final step is to combine the total direct plus indirect utilities that are expressed in fundamental energy units. In Table 5-9, the first rows show the direct utilities, electric power, fuel gas, and natural gas consumed directly in processing. The indirect utilities that were translated to fundamental energy units are shown next. Before summing up direct and indirect utilities, it is necessary to account for the fuel gas imbalance. In the refinery modeling, it is assumed that fuel gas supplies heat to the process units, including the hydrogen plant. It is only at the end that it is determined if there is enough fuel gas. When the fuel gas production is not sufficient to supply the heat required, natural gas is imported. The net import of natural gas is shown in Tables 5-5 (Net Fuel Gas deficit) and 5-9 (Natural Gas Added to Balance Fuel Gas). To keep the energy balanced and to facilitate emissions calculation, the supplemental natural gas is subtracted from

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the fuel gas and added to natural gas. The results of this accounting are shown in Table 5-9, which also shows the final distribution of energy to the products in fundamental units of energy, kW of electricity and MMBtu/hr of fuel gas and natural gas.

- Table 5-10 shows the energy used to produce each product in GJ/hr for electricity, fuel gas and natural gas. Table 5-10 also shows the energy content of the feeds (crude, diluent, iC4 for alkylation) in the products. This will be used later to add the upstream GHG burden from the feeds to the products.

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Table 5-8.
Translation of Utilities Produced in Utility Plants to Fundamental Energy Units – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
Hydrogen	Klb/day	-7.3	-3.4	-98.4	-43.0	-294.3	-1.8	0.0	-448.1
Total Indirect Utilities from Utility Plants									
Steam	Klb/hr	-11	-7	-217	-147	-126	-5	-65	-578
Cooling Water	GPM	-1,864	-991	-22,575	-16,127	-6,872	-1,356	-1,579	-51,363
BFW	Klb/hr	-10	-7	-322	-231	-74	-19	-97	-760
Conversion of Indirect Utility Units to Fundamental Energy Units									
Cooling Water -- Power	KW	-47	-25	-564	-403	-172	-34	-39	-1,284
Steam Generation -- Power	KW	-12	-7	-224	-153	-130	-5	-67	-599
BFW Prep -- Power	KW	-11	-7	-330	-237	-76	-20	-99	-779
H2 Plant -- Power	KW	-45	-21	-603	-263	-1,804	-11	0	-2,748
Steam Generation -- Fuel Gas	MMBtu/hr	-15	-9	-278	-189	-162	-7	-83	-742
BFW Prep -- Fuel Gas	MMBtu/hr	-1	-1	-34	-24	-8	-2	-10	-80
H2 Plant -- Fuel Gas	MMBtu/hr	-6	-3	-81	-35	-241	-1	0	-367
H2 Plant -- Natural Gas	MMBtu/hr	-18	-9	-245	-107	-731	-4	0	-1,114
Indirect Consumption of Primary Utilities									
Power	KW	-114	-60	-1,722	-1,056	-2,182	-70	-205	-5,410
Fuel Gas	MMBtu/hr	-22	-12	-393	-249	-410	-10	-93	-1,189
Natural Gas as H2 Plant Feed	MMBtu/hr	-18	-9	-245	-107	-731	-4	0	-1,114

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Table 5-9.
Combining Direct and Indirect Utilities—Results Reported in Fundamental Energy Units – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
Total Direct Utilities									
Power	KW	-899	-705	-29,695	-21,582	-21,510	-1,873	-2,865	-79,130
Steam	Klb/hr	-11	-7	-217	-147	-126	-5	-65	-578
Fuel Gas	MM BTU/hr	-18	-14	-528	-406	-250	-69	0	-1,285
Natural Gas as Fuel	MM BTU/hr	0	0	-8	-6	-8	-2	0	-24
FCC Coke	MM BTU/h	-11	-6	-208	-130	-57	-4	0	-415
Cooling Water	GPM	-1,864	-991	-22,575	-16,127	-6,872	-1,356	-1,579	-51,363
BFW	Klb/hr	-10	-7	-322	-231	-74	-19	-97	-760
Total Indirect Utilities									
Power	KW	-114	-60	-1,722	-1,056	-2,182	-70	-205	-5,410
Fuel Gas	MMBtu/hr	-22	-12	-393	-249	-410	-10	-93	-1,189
Natural Gas as H2 Plant Feed	MMBtu/hr	-18	-9	-245	-107	-731	-4	0	-1,114
									0.00%
Total Fuel Gas Consumed	MMBtu/hr	-40	-26	-921	-655	-660	-79	-93	-2,474
Natural Gas Added to Balance Fuel Gas	MM BTU/hr	-15	-10	-339	-241	-243	-29	-34	-910
Credit for Fuel Gas for Natural Gas Needed to Balance Fuel Gas	MM BTU/hr	15	10	339	241	243	29	34	910
Total Primary Utility Consumption (Direct + Indirect)									
Total Power	KW	-1,013	-764	-31,419	-22,639	-23,694	-1,944	-3,071	-84,544
Total Refinery Fuel Gas Consumed	MM BTU/hr	-25	-16	-582	-414	-417	-50	-59	-1,563
Direct Fuel Gas to Products	MM BTU/hr	-18	-14	-528	-406	-250	-69	0	-1,285
Indirect Fuel Gas	MM BTU/hr	-22	-12	-393	-249	-410	-10	-93	-1,189
Credit for Natural Gas Addded to Balance Fuel Gas Heat	MM BTU/hr	15	10	339	241	243	29	34	910
Total Natural Gas Consumed	MM BTU/hr	-33	-18	-591	-353	-982	-36	-34	-2,048
As Neat Fuel	MM BTU/hr	0	0	-8	-6	-8	-2	0	-24
Process Feed to H2 Plant	MM BTU/hr	-18	-9	-245	-107	-731	-4	0	-1,114
Imported to Supplement Fuel Gas	MM BTU/hr	-15	-10	-339	-241	-243	-29	-34	-910
FCC Coke	MM BTU/h	-11	-6	-208	-130	-57	-4	0	-415

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Table 5-10.
Direct and Indirect Utilities Reported in GJ/hr – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
Total Primary Utility Consumption (Direct + Indirect) - GJ/hr Basis									
Total Power - GJ/hr	GJ/hr	-4	-3	-113	-82	-85	-7	-11	-304
Total Refinery Fuel Gas - GJ/hr	GJ/hr	-27	-17	-614	-437	-440	-53	-62	-1,649
Direct Fuel Gas to Products	GJ/hr	-19	-14	-557	-428	-264	-73	0	-1,355
Indirect Fuel Gas	GJ/hr	-23	-13	-414	-262	-433	-11	-98	-1,254
Credit for Natural Gas Addded to Balance Fuel Gas Heat	GJ/hr	15	10	357	254	256	31	36	960
Total Natural Gas - GJ/hr	GJ/hr	-35	-19	-624	-373	-1,036	-38	-36	-2,161
As Neat Fuel - GJ/hr	GJ/hr	0	0	-8	-6	-8	-2	0	-26
Process Feed to H2 Plant - GJ/hr	GJ/hr	-19	-9	-258	-113	-771	-5	0	-1,175
Imported to Supplement Fuel Gas - GJ/hr	GJ/hr	-15	-10	-357	-254	-256	-31	-36	-960
Natural Gas to Cogen - GJ/hr	GJ/hr	0	0	0	0	0	0	0	0
FCC Coke - GJ/hr	GJ/hr	-11	-6	-220	-137	-60	-4	0	-438
Distribution of Feeds to Products on a GJ/hr Basis									
Diluent - Net Heating Value in Products	GJ/hr	0	0	0	0	0	0	0	0
Crude - Net Heating Value in Products	GJ/hr	571	508	11,290	7,896	11,257	2,058	0	33,581
Isobutane - Net heating Value in Products	GJ/hr	0	0	370	266	0	0	0	636

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From Energy to GHG Emissions

The next step is to convert energy used in producing each product shown in Table 5-10 to GHG emissions using the emission factors from GREET (Table 5-11). These emission factors allow the calculation of emissions of VOC, CO, NOx, PM10, PM2.5, SOx, CH_4: combustion, N_2O, and CO_2 for each energy type used in different energy consuming processes.

Table 5-11.
Emission Factors from GREET

Emissions	Natural Gas	Natural Gas as H2 Plant Feed	NG to Cogen	Fuel Gas	FCC Coke	Power
	g/MMBtu	g/MMBtu	g/MMBtu	g/MMBtu	g/MMBtu	g/MMBtu
VOC	7.2	0.3	7.2	7.2	7.2	26.5
CO	24.1	1.0	24.1	24.1	24.1	70.2
NOx	79.4	0.0	79.4	79.4	79.4	331.0
PM10	4.0	0.0	4.0	4.0	4.0	478.6
PM2.5	3.7	0.0	3.7	3.7	3.7	124.7
SOx	11.8	0.0	11.8	11.8	11.8	784.0
CH_4: combustion	176.4	2.7	176.4	176.4	176.4	387.3
N_2O	1.2	0.0	1.2	1.2	1.2	3.5
CO_2	64,539	58,179	64,539.0	60,000	102,120	320,082

For this analysis we are only interested in the gases that contribute to global warming: N_2O, CH_4, and CO_2. Results for these emissions for each product are shown in Table 5-12. Consolidating the emissions of N_2O, CH_4 and CO_2 on the basis of global warming potential can be done using the Global Warming Potential (GWP) factors from IPCC shown in Table 5-13, which reports that N_2O has a GWP 298 times CO_2 and CH_4 has a GWP 25 times that of CO_2.

Results for Global warming potential reported on a CO_2 equivalent basis—here called GHG emissions—are shown in Table 5-14. Results are reported as kg of GHG emissions per barrel of crude processed. Table 5-14 shows (as MJ/bbl of crude processed) the energy needed to produce each product, as well as the contribution of each product to overall GHG emissions and energy used. Note that the emissions shown in this table do not include the upstream emission burden brought in with the crude, the iC4 for alkylation, the diluent for dilbit, or the electric power and natural gas used in processing. These will be added later.

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Table 5-12.
GHG Emissions for Each Product from Refining – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur
Emissions from Power								
CH4: combustion	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.03
N2O	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2	Kg/GJ	1.95	1.67	3.20	3.29	2.41	0.80	24.86
Emissions from Fuel Gas								
CH4: combustion	Kg/GJ	0.01	0.01	0.01	0.01	0.01	0.00	0.08
N2O	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2	Kg/GJ	2.67	1.96	3.26	3.30	2.33	1.14	26.22
Emissions from Combustion of Natural Gas								
CH4: combustion	Kg/GJ	0.00	0.00	0.01	0.01	0.00	0.00	0.05
N2O	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2	Kg/GJ	1.72	1.28	2.09	2.12	1.51	0.76	16.46
Emissions from Natural Gas Used as Process Feed to H2 Plant								
CH4: combustion	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N2O	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2	Kg/GJ	1.86	0.99	1.33	0.83	3.96	0.10	0.00
Emissions from FCC Coke Used as FCC unit Process Heat								
CH4: combustion	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N2O	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2	Kg/GJ	1.92	1.14	1.98	1.76	0.55	0.14	0.00
Total Emissions - Based on "Inside the Box" Analysis								
CH4: combustion - Total	Kg/GJ	0.02	0.01	0.02	0.02	0.02	0.01	0.15
N2O -Total	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 -Total	Kg/GJ	10.13	7.05	11.85	11.29	10.75	2.94	67.55
Total Emissions - Based on Averaging Overall Emissions								
CH4: combustion Average	Kg/GJ	0.02	0.02	0.02	0.02	0.02	0.02	0.02
N2O Average	Kg/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 Average	Kg/GJ	10.77	10.77	10.77	10.77	10.77	10.77	10.77

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Table 5-13.
New IPCC Global Warming Potential (100-Year Time Horizon)

	GREET
Carbon dioxide (CO2)	1
Methane (CH_4)*	25
Nitrous oxide (N_2O)	298

*The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Another way to look at GHG emissions and energy use is on an intrinsic basis. Table 5-15 shows GHG emissions in g of GHG per MJ of product produced and energy in terms of MJ of energy per MJ of product produced. Looking at the information in this manner enables a comparison of processing intensity to make each product. As can be seen from an examination of this table, some products like coke require much less energy to produce and result in much lower GHG emissions per unit of product produced than other products like C3 LPG, gasoline or diesel.

- Coke: 3.1 g of GHG per MJ of coke produced
- LPG: 10.2 g of GHG per MJ of C3 produced
- CBOB: 12.5 g of GHG per MJ of CBOB gasoline produced
- RBOB: 11.9 g of GHG per MJ of RBOB gasoline produced
- ULSD: 11.2 g of GHG per MJ of ULSD produced

The average GHG intensity is 11.2 g GHG/MJ of products. Clearly, using the average GHG/MJ of product would unduly penalize coke and reward the other products. Note that the GHG intensity for sulfur looks high because its LHV is low. The contribution of sulfur to overall GHG emissions from refining is small.

The contributions to overall energy use and to GHG emissions from power, refinery fuel gas, natural gas and FCC coke is shown for refining Arab-Medium crude in Figure 5-13. The assumption that electric power is produced from coal-fired power plants results in a much greater impact on total GHG emissions than on total energy use.

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Table 5-14.
Consolidated GHG Emissions and Energy to Refine Arab-Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
Total GHG Emissions	kg GHG/bbl of crude	1.03	0.63	22.92	15.35	20.55	1.41	1.66	63.55
GHG Emissions from Power	kg GHG/bbl of crude	0.20	0.15	6.08	4.38	4.58	0.38	0.59	16.36
GHG Emissions from Fuel Gas	kg GHG/bbl of crude	0.28	0.18	6.46	4.59	4.63	0.56	0.65	17.36
GHG Emissions from Combustion of Natural Gas	kg GHG/bbl of crude	0.18	0.12	4.12	2.93	2.98	0.37	0.41	11.10
GHG Emissions from Natural Gas Used as Process Feed to H2 Plant	kg GHG/bbl of crude	0.18	0.08	2.44	1.07	7.30	0.04	0.00	11.12
GHG Emissions from FCC Coke Used as FCC unit Process Heat	kg GHG/bbl of crude	0.19	0.10	3.81	2.38	1.05	0.07	0.00	7.61
Total Energy	MJ/Bbl of Crude	-13.11	-7.76	-269.22	-176.15	-278.06	-17.34	-18.78	-780.43
Power	MJ/Bbl of Crude	-0.63	-0.47	-19.39	-13.97	-14.62	-1.20	-1.90	-52.18
Fuel Gas	MJ/Bbl of Crude	-4.56	-2.95	-105.25	-74.83	-75.45	-9.05	-10.66	-282.77
Combustion of Natural Gas	MJ/Bbl of Crude	-2.73	-1.79	-62.71	-44.57	-45.37	-5.63	-6.22	-169.02
Natural Gas Used as Process Feed to H2 Plant	MJ/Bbl of Crude	-3.27	-1.54	-44.23	-19.31	-132.24	-0.80	0.00	-201.39
FCC Coke Used as FCC unit Process Heat	MJ/Bbl of Crude	-1.92	-1.01	-37.64	-23.47	-10.37	-0.66	0.00	-75.08

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Table 5-15.
GHG and Energy Intensity to Produce Products from Refining Arab-Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
GHG Intensity	g GHG/MJ of Product	10.63	7.41	12.46	11.91	11.16	3.12	71.68	11.29
GHG from Power	g GHG/MJ of Product	2.02	1.73	3.31	3.40	2.49	0.83	25.70	2.91
GHG from Fuel Gas	g GHG/MJ of Product	2.89	2.12	3.51	3.56	2.51	1.23	28.30	3.08
GHG from Combustion of Natural Gas	g GHG/MJ of Product	1.85	1.37	2.24	2.27	1.62	0.82	17.68	1.97
GHG from Natural Gas as Process Feed to H2 Plant	g GHG/MJ of Product	1.86	0.99	1.33	0.83	3.96	0.10	0.00	1.98
GHG from Coke Used as FCC unit Process Heat	g GHG/MJ of Product	2.01	1.20	2.07	1.84	0.57	0.15	0.00	1.35
Energy Intensity	MJ/MJ of Product	-0.135	-0.091	-0.146	-0.137	-0.151	-0.038	-0.812	-0.139
Power	MJ/MJ of Product	-0.006	-0.006	-0.011	-0.011	-0.008	-0.003	-0.082	-0.009
Fuel Gas	MJ/MJ of Product	-0.047	-0.035	-0.057	-0.058	-0.041	-0.020	-0.461	-0.050
Combustion of Natural Gas	MJ/MJ of Product	-0.028	-0.021	-0.034	-0.035	-0.025	-0.012	-0.269	-0.030
Natural Gas Used as Process Feed to H2 Plant	MJ/MJ of Product	-0.034	-0.018	-0.024	-0.015	-0.072	-0.002	0.000	-0.036
FCC Coke Used as FCC unit Process Heat	MJ/MJ of Product	-0.020	-0.012	-0.020	-0.018	-0.006	-0.001	0.000	-0.013

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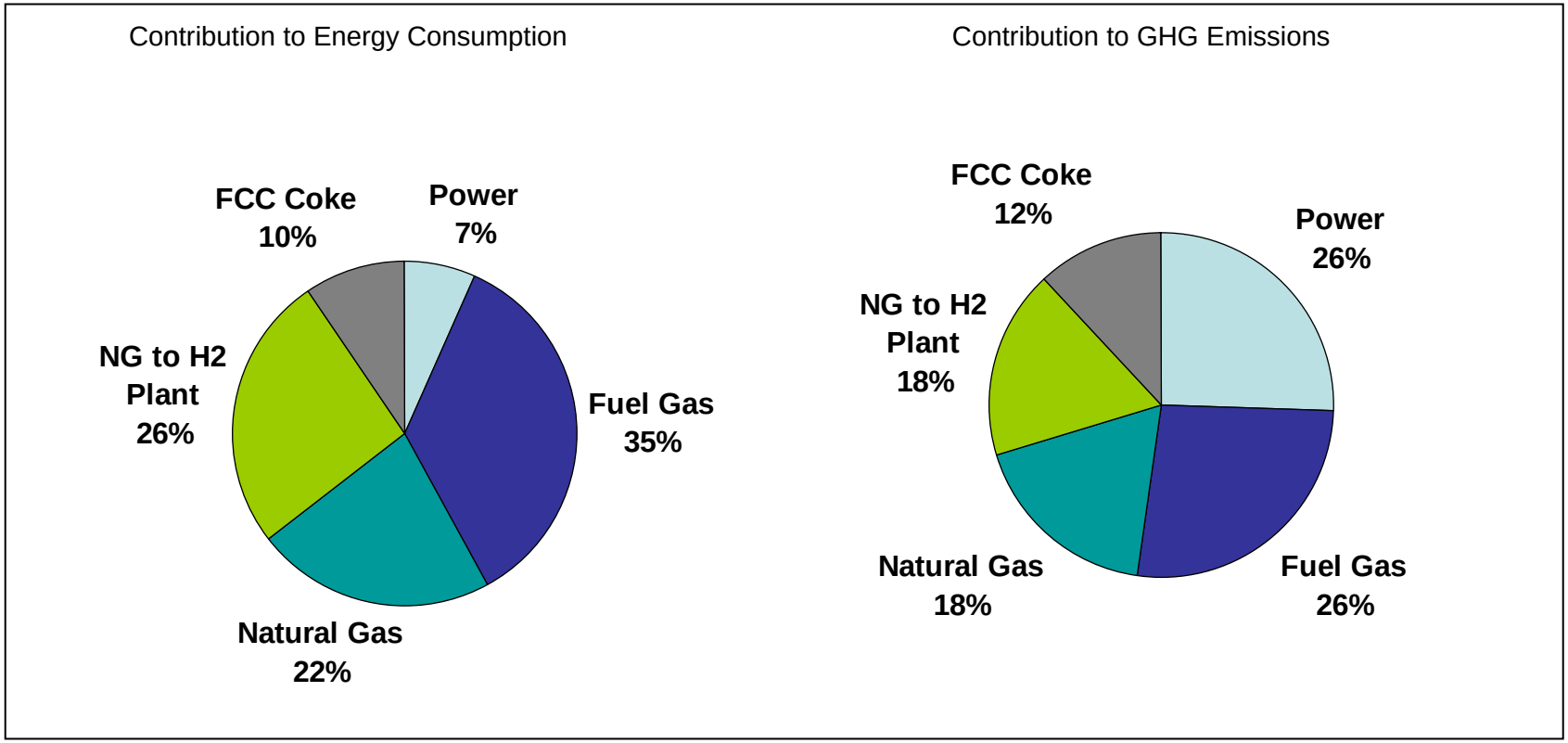
Figure 5-13.
Contributors to Energy Consumption and GHG Emissions from Refining Arab-Medium Crude Oil



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Dealing with Coproducts from Refining

The major products in this analysis are the two grades of gasoline, CBOB and RBOB and diesel. The other products—C3 LPG, C4s, coke and sulfur—are coproducts and are produced as a result of producing the major products. One question in life cycle analysis is what to do with the GHG emissions from producing these coproducts and what to with the emissions from using these coproducts. The decision was made for this analysis to distribute the GHG emissions from producing and using the coproducts to the major products, gasoline and diesel. This was done by prorating the emissions on the basis of major product net heating value. The first step is to distribute the GHG emissions from producing coke, sulfur, C3 and C4. It is also necessary to distribute the energy, power, natural gas and fuel gas because later the upstream burden for producing this power and for producing natural gas will also be added. It is also necessary to keep track of how much of each coproduct is distributed to the major product in case there is a need to add downstream GHG emissions (*e.g.,* the emission impact from combustion of coke, LPG or C4s relative to the fuels that they replace).

Table 5-16 shows the results from consolidating the emissions and energy from the coproducts to the major products. Also shown in Table 5-16 is the consolidation of energy and feeds from the coproducts to the major products. Results are reported on the basis of total emissions, total feed and total energy to process 140,000 BPD of crude.

Table 5-17 reports the same results, but on the basis of energy or GHG emissions per MJ of product; results in Table 5-17 are therefore independent of the quantity of feed processed.

Comparison of GHG Emissions for Refining Different Crudes, SCOs, and Bitumen

The same methodology described above is used in evaluating the energy used and GHG emissions from the other crudes, bitumens, and SCOs evaluated in this study.

Figure 5-14 compares the energy to refine each crude. Results are reported on an MJ of fuel per barrel of crude processed. Figure 5-15 compares the GHG emissions from refining the different crudes on a kg of GHG/bbl of crude basis and shows the major contributors to GHG emissions. Crude API is also shown in Figures 5-14 and 5-15. In general, heavier crudes (lower API) require more energy and result in greater GHG emissions than lighter crudes. Figure 5-16 shows GHG emissions distributed to the major products on a barrel of crude basis. Heavier crudes require more energy to refine and result in more GHG emissions.

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Table 5-16.
Consolidation of GHG Emissions, Energy, and Feeds from Coproducts to Major Products – Arab Medium Crude

	Units	C3	C4	CBOB	RBOB	Diesel	Coke	Sulfur	Total
Total Primary Utility Consumption (Direct + Indirect) - GJ/hr Basis									
Total Power - GJ/hr	GJ/hr	-3.6	-2.8	-113.1	-81.5	-85.3	-7.0	-11.1	-304.4
Total Refinery Fuel Gas - GJ/hr	GJ/hr	-26.6	-17.2	-614.0	-436.5	-440.1	-52.8	-62.2	-1,649.5
Direct Fuel Gas to Products	GJ/hr	-19.1	-14.5	-557.0	-428.3	-263.5	-72.7	0.0	-1,355.2
Indirect Fuel Gas	GJ/hr	-23.0	-12.8	-414.3	-262.3	-432.8	-10.9	-98.3	-1,254.4
Credit for Natural Gas Addded to Balance Fuel Gas Heat	GJ/hr	15.5	10.0	357.4	254.1	256.2	30.7	36.2	960.1
Total Natural Gas - GJ/hr	GJ/hr	-35.0	-19.4	-623.8	-372.6	-1,036.1	-37.5	-36.3	-2,160.7
As Neat Fuel - GJ/hr	GJ/hr	-0.4	-0.4	-8.4	-5.9	-8.5	-2.1	-0.1	-25.8
Process Feed to H2 Plant - GJ/hr	GJ/hr	-19.1	-9.0	-258.0	-112.6	-771.4	-4.7	0.0	-1,174.8
Imported to Supplement Fuel Gas - GJ/hr	GJ/hr	-15.5	-10.0	-357.4	-254.1	-256.2	-30.7	-36.2	-960.1
FCC Coke - GJ/hr	GJ/hr	-11.2	-5.9	-219.6	-136.9	-60.5	-3.8	0.0	-437.9
Distribution of Feeds to Products									
Crude - Net Heating Value in Products	GJ/hr	571.2	508.0	11,290.5	7,896.1	11,257.5	2,057.8	0.0	33,581.2
Hydrogen - Net Heating Value in Products	GJ/hr	-16.5	-7.7	-222.5	-97.1	-665.2	-4.0	0.0	-1,013.1
Isobutane - Net heating Value in Products	GJ/hr	0.0	0.0	369.8	266.2	0.0	0.0	0.0	636.0
Total GHG Emissions Before Adding Upstream Burden	MTD	144	89	3,208	2,149	2,877	198	232	8,897
GHG Emissions from Power	MTD	27	21	851	613	642	53	83	2,290
GHG Emissions from Fuel Gas	MTD	39	25	905	643	649	78	92	2,430
GHG Emissions from Combustion of Natural Gas	MTD	25	16	577	410	417	52	57	1,554
GHG Emissions from Natural Gas Used as Process Feed to H2 Plant	MTD	25	12	342	149	1,022	6	0	1,557
GHG Emissions from FCC Coke Used as FCC unit Process Heat	MTD	27	14	534	333	147	9	0	1,065
Total Primary Utility Consumption After Consolidation									
Total Power - after Consolidation	GJ/hr			-122	-88	-94			-304
Total Refinery Fuel Gas - after Consolidation	GJ/hr			-673	-478	-499			-1,649
Direct Fuel Gas to Products	GJ/hr			-596	-456	-303			-1,355
Indirect Fuel Gas	GJ/hr			-468	-300	-487			-1,254
Credit for Natural Gas Addded to Balance Fuel Gas Heat	GJ/hr			392	278	290			960
Total Natural Gas - after Consolidation	GJ/hr			-671	-406	-1,084			-2,161
As Neat Fuel - GJ/hr	GJ/hr			-10	-7	-10			-26
Process Feed to H2 Plant - GJ/hr	GJ/hr			-270	-121	-784			-1,175
Imported to Supplement Fuel Gas - GJ/hr	GJ/hr			-392	-278	-290			-960
FCC Coke - after Consolidation	GJ/hr			-227	-142	-68			-438
Distribution of Feeds to Products after Consolidation									
Diluent - Net Heating Value in Products	GJ/hr			0	0	0			
Crude - Net Heating Value in Products	GJ/hr			12,451	8,710	12,420			33,581
Hydrogen - Net Heating Value in Products	GJ/hr			-233	-104	-676			-1,013
Isobutane - Net heating Value in Products	GJ/hr			370	266	0			636
Total GHG emissions after Consolidation to Major Products	MTD			3,454	2,320	3,123			8,897
GHG from Power after Consolidation	MTD			919	661	710			2,290
GHG from Fuel Gas after Consolidation	MTD			991	704	735			2,430
GHG from Combustion of Natural Gas after Consolidation	MTD			632	449	473			1,554
GHG from Natural Gas as Process Feed to H2 Plant after Consolidation	MTD			358	161	1,038			1,557
GHG from Coke Used as FCC unit Process Heat after Consolidation	MTD			553	346	166			1,065

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Figure 5-17.
GHG Emissions, Energy and Feed Shares for Each Major Product – Arab Medium Crude

	Units	CBOB	RBOB	Diesel
Total Primary Utility Share				
Total Power Share - after Consolidation	MJ Energy/MJ of Product	-0.0114	-0.0117	-0.0088
Total Refinery Fuel Gas Share - after Consolidation	MJ Energy/MJ of Product	-0.0627	-0.0635	-0.0464
Direct Fuel Gas to Products	MJ Energy/MJ of Product	-0.0556	-0.0606	-0.0282
Indirect Fuel Gas	MJ Energy/MJ of Product	-0.0436	-0.0399	-0.0453
Credit for Natural Gas Addded to Balance Fuel Gas Heat	MJ Energy/MJ of Product	0.0365	0.0370	0.0270
Total Natural Gas Share - after Consolidation	MJ Energy/MJ of Product	-0.0626	-0.0540	-0.1009
As Neat Fuel - GJ/hr	MJ Energy/MJ of Product	-0.0009	-0.0009	-0.0009
Process Feed to H2 Plant - GJ/hr	MJ Energy/MJ of Product	-0.0252	-0.0161	-0.0729
Imported to Supplement Fuel Gas - GJ/hr	MJ Energy/MJ of Product	-0.0365	-0.0370	-0.0270
FCC Coke Share - after Consolidation	MJ Energy/MJ of Product	-0.0212	-0.0189	-0.0064
Diluent Share - Net Heating Value in Products	MJ Feed/MJ of Product	0.0000	0.0000	0.0000
Crude Share - Net Heating Value in Products	MJ Feed/MJ of Product	1.1609	1.1583	1.1560
Hydrogen Share - Net Heating Value in Products	MJ Feed/MJ of Product	-0.0217	-0.0139	-0.0629
Isobutane Share - Net heating Value in Products	MJ Feed/MJ of Product	0.0345	0.0354	0.0000
Total GHG Emissions after Consolidation to Major Products	g GHG/MJ of Product	13.4	12.9	12.1
GHG Share from Power after Consolidation	g GHG/MJ of Product	3.6	3.7	2.8
GHG Share from Fuel Gas after Consolidation	g GHG/MJ of Product	3.9	3.9	2.9
GHG Share from Combustion of Natural Gas after Consolidation	g GHG/MJ of Product	2.5	2.5	1.8
GHG Share from Natural Gas as Process Feed to H2 Plant after Consolidati	g GHG/MJ of Product	1.4	0.9	4.0
GHG Share from Coke Used as FCC unit Process Heat after Consolidation	g GHG/MJ of Product	2.1	1.9	0.6

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Figure 5-14.
Energy Used to Refine Crude, SCO, Bitumen, or Dilbit

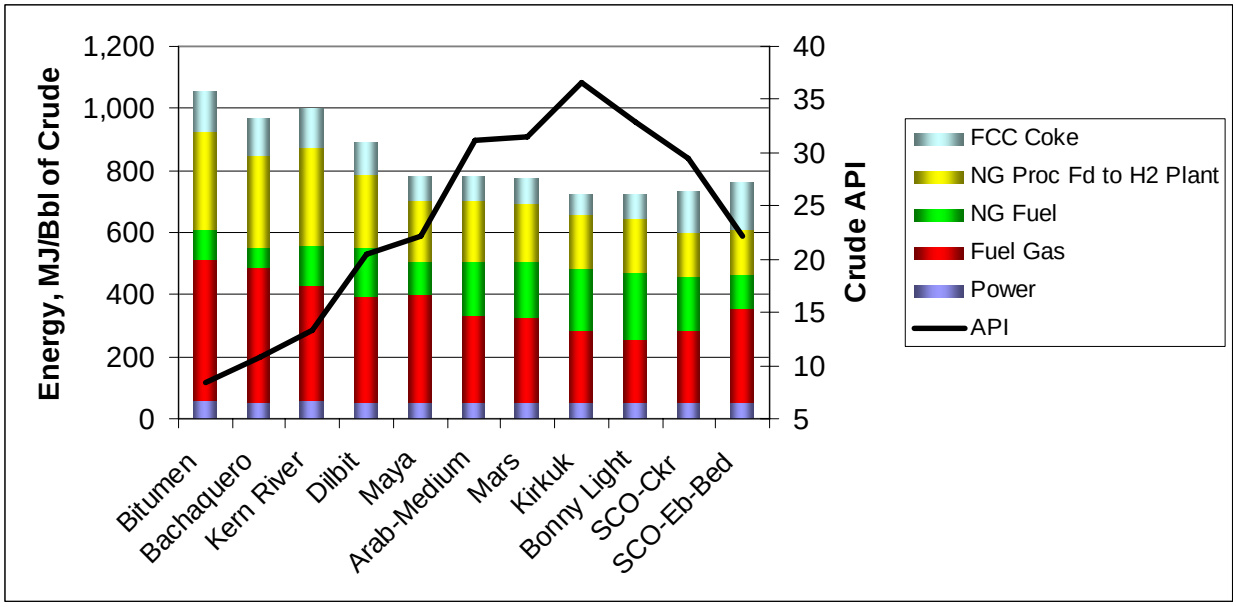

Figure 5-15.
GHG Emissions from Energy Sources Used to Refine Crude, SCO, Bitumen, or Dilbit

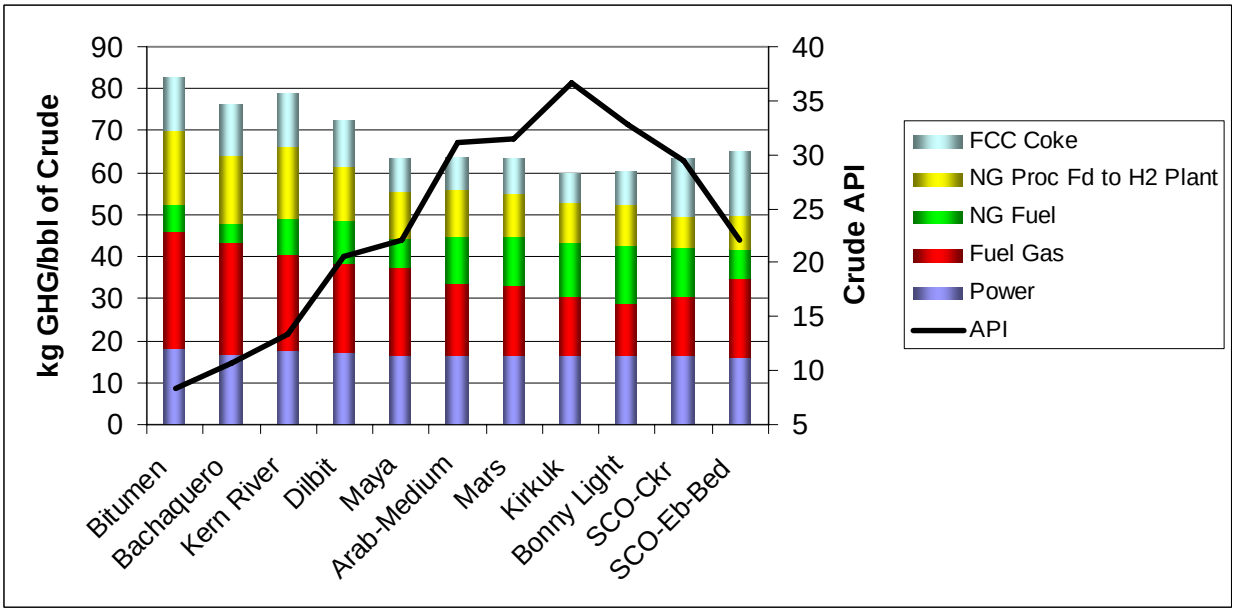

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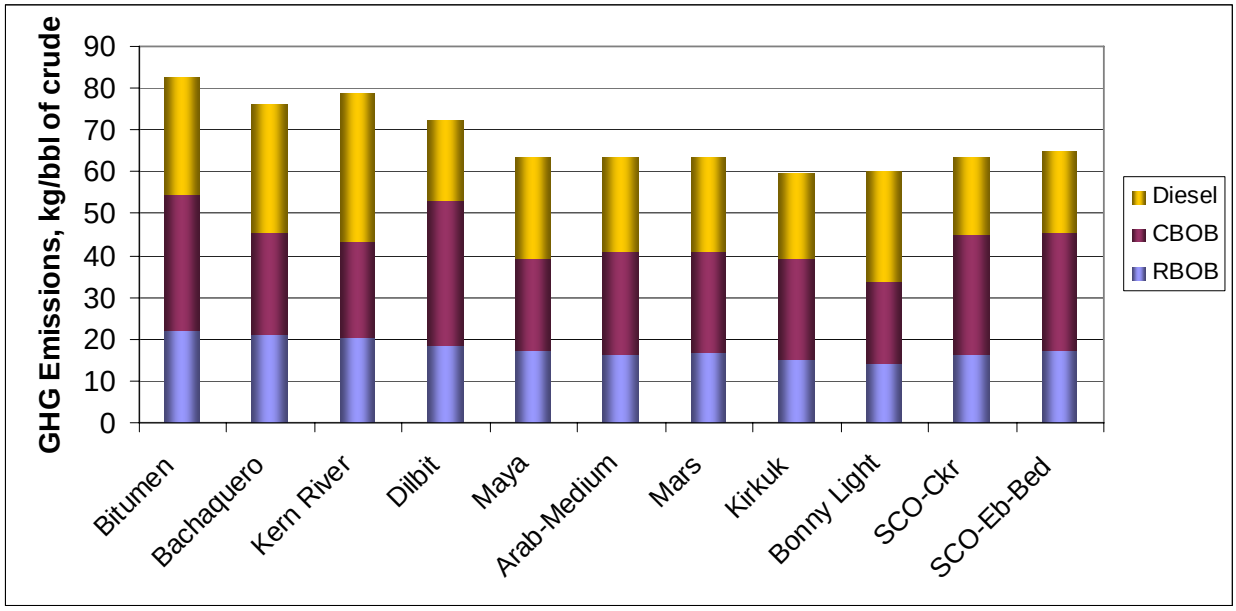
Figure 5-16.
Product GHG Emissions from Refining Crude, SCO, Bitumen or Dilbit



Validity of Crude Analysis Methodology

One of the questions raised earlier was whether it is valid to process each crude separately instead of as part of a mixture of crudes, which is more how refineries operate. In this analysis there were no constraints on processing capacity because the objective was to understand the impact of each crude on GHG emissions. Table 5-18 shows good agreement between processing the following seven conventional crudes together vs. summing the results of processing each separately.

- Bachaquero
- Kern River
- Maya
- Arab-Medium
- Mars
- Kirkuk
- Bonny Light

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Results in the column labeled “Results from a Mixture of 7 Crudes” are from processing a mix of 20,000 BPD each of the seven crudes. Results in the Column labeled “Blend Results from 7 Individual Crudes” are from a paper blend of the results from processing each crude separately. The difference is within a few percent on most results, shown in Table 5-18 and the difference in overall GHG emissions is less than 1%.

Table 5-18.
Processing a Mix of Crudes vs. Summing the Results from Processing Each Separately

Crude	Units	Results from a Mixture of 7 Crudes	Blend Results from 7 Individual Crudes	Error
Feeds to Refining				
Crude	BPSD	140,000	140,000	0.0%
API		24.9	24.3	-2.3%
Sulfur	wt%	1.95	1.94	-0.8%
i-C4 Purchase	BPSD	4,145	3,945	-4.8%
Products				
C3	BPSD	3,402	3,380	-0.7%
C4	BPSD	1,763	1,842	4.5%
CBOB	BPSD	48,981	47,046	-4.0%
RBOB	BPSD	35,000	35,000	0.0%
Diesel	BPSD	49,534	49,940	0.8%
Coke	Klb/day	4,394	4,678	6.5%
Sulfur	Klb/day	612	606	-1.0%
Process Unit Capacity				
Crude Unit	BPSD	140,000	140,000	0.0%
Vacuum Unit	BPSD	77,287	77,287	0.0%
Coking Unit	BPSD	39,785	41,607	4.6%
Naptha Hydrotreater	BPSD	43,445	43,727	0.7%
Diesel Hydrotreater	BPSD	54,648	55,044	0.7%
Gas Oil Hydrotreating Unit	BPSD	50,463	48,727	-3.4%
Naphtha Splitter	BPSD	44,472	44,767	0.7%
Reformer	BPSD	31,797	32,009	0.7%
Isom Unit	BPSD	15,106	15,224	0.8%
FCC	BPSD	44,328	42,776	-3.5%
Alky	BPSD Alkylate	13,878	13,355	-3.8%
Sulfur Plant	MTD	278	275	-1.0%
H2 Plant (SMR)	MMSCFD	93	92	-0.9%
Hydrogen Producers				
H2 Plant	MM SCFD	93	92	-0.9%
Reformer	MM SCFD	41	41	0.2%
Subtotal	MM SCFD	134	133	-0.6%
Hydrogen Consumers			0	
NHT	MM SCFD	23	23	1.1%
Isom	MM SCFD	3	4	21.2%
DHT	MM SCFD	58	59	0.8%
GOHT	MM SCFD	50	48	-4.2%
Subtotal	MM SCFD	134	133	-0.6%
Utility Requirements				
Electric Power Required	MW	86	85	-0.4%
Electric Power Generated in Plant	MW	0	0	
Natural Gas Total	MM BTU/hr	2,074	2,050	-1.2%
Natural Gas as Feed to the H2 Plant	MM BTU/hr	1,228	1,217	-0.9%
Total GHG Emissions	MTD	9,393	9,316	-0.8%

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Adding Upstream Burden

The results reported here do not include upstream GHG burden for producing crude, bitumen, SCO, diluent or iC4 used in alkylation. In addition, these results do not include the upstream burden for producing natural gas or electric power used in refining.

Table 5-19 shows the GHG emissions attributed to CBOB, RBOB, and diesel during refining, including the coproduct GHG emissions that were distributed to the major products using the methodology discussed above. Table 5-19 also shows the allocation of crude and diluent as well as the power and natural gas brought in for refining the crudes. Allocation of feeds and energy streams is necessary to account for upstream GHG burden for producing these streams in the overall WTW analysis. Distribution of feeds and energy streams to the major products is per the methodology discussed above. Note that the iC4 used in alkylation is allocated to CBOB and RBOB but is not shown in this table. It will be included in a subsequent section which completes the WTW analysis.

Next we will consider the transport of crude and distribution of fuel products. Finally, following this discussion, the GHG emissions from all the different sources in the life cycle assessment, including the upstream burden for streams and energy sources will be rolled up to complete the WTW analysis for each crude and bitumen.

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Table 5-19.
Distribution of GHG, Crude, Diluent, Power, Fuel Gas, and Natural Gas to CBOB, RBOB and Diesel

Crude	Units	Bitumen	Bachaquero	Kern River	Dilbit	Maya	Arab-Medium	Mars	Kirkuk	Bonny Light	SCO-Ckr	SCO-Eb-Bed
CBOB												
GHG Burden with Byproduct GHG Add Back	g/MJ	17.23	16.16	15.12	13.88	13.73	13.42	12.53	12.40	11.29	12.42	13.29
Crude Specific Energy with Byproduct Add Back	GJ/GJ	1.23	1.26	1.18	1.15	1.27	1.16	1.14	1.13	1.06	1.04	1.13
Diluent Specific Energy with Byproduct Add Back	GJ/GJ	0.00	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.10	0.10	0.08	0.07	0.08	0.06	0.06	0.05	0.04	0.05	0.06
Electricity Specific Energy with Byproduct Add Back	GJ/GJ	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.07	0.05	0.06	0.06	0.04	0.06	0.05	0.06	0.05	0.05	0.04
RBOB												
GHG Burden with Byproduct GHG Add Back	g/MJ	17.25	16.22	15.68	14.70	13.49	12.86	13.14	11.85	10.81	12.64	13.43
Crude Specific Energy with Byproduct Add Back	GJ/GJ	1.25	1.27	1.17	1.14	1.27	1.16	1.14	1.13	1.07	1.04	1.13
Diluent Specific Energy with Byproduct Add Back	GJ/GJ	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.09	0.10	0.08	0.07	0.08	0.06	0.06	0.05	0.04	0.05	0.07
Electricity Specific Energy with Byproduct Add Back	GJ/GJ	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.07	0.05	0.07	0.06	0.04	0.05	0.05	0.05	0.04	0.05	0.04
Diesel												
GHG Burden with Byproduct GHG Add Back	g/MJ	14.77	14.06	13.69	13.06	13.16	12.11	12.03	11.50	10.62	8.87	9.82
Crude Specific Energy with Byproduct Add Back	GJ/GJ	1.26	1.27	1.17	1.17	1.26	1.16	1.13	1.12	1.04	1.04	1.13
Diluent Specific Energy with Byproduct Add Back	GJ/GJ	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.08	0.08	0.06	0.05	0.06	0.05	0.04	0.04	0.03	0.03	0.04
Electricity Specific Energy with Byproduct Add Back	GJ/GJ	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas Specific Energy with Byproduct Add Back	GJ/GJ	0.10	0.09	0.09	0.10	0.09	0.10	0.10	0.10	0.09	0.06	0.05

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Section 6.

Transport and Delivery

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Feedstock and Fuel Transport

Crude Oil and Product Flows

The source of petroleum resources and disposition of products affects the energy inputs associated with transportation. Petroleum transport is a relatively small portion of the fuel cycle GHG emissions when compared to the total for average processes. However, transport distances and delivery modes vary considerably among the crude oil resources in this Study.

Petroleum products are produced in refineries around the world with significant imports of finished product to the US. Since most of the imported Canadian crude oil is processed in PADD 2 (Midwest - Petroleum Administration for Defense District), the Midwest refinery locations were used to calculate transport emissions. While the use or displacement of Canadian crude oils could results in a variety of crude oil and refined product movements the scenario for Midwest refining illustrates the effect of crude oil transport. Figure 6-1 shows the primary sources of imported crude oil to PADD 2 and the associated marine transport distances to the Gulf coast.

Transportation Modes

Crude oil and refined products are transported through a variety of delivery modes including pipelines, marine tankers, barges, and trucks. For the analysis there, the crude oil transport mode was assumed to be from oil field to marine terminal by pipeline with marine tanker transport to the Gulf coast and pipeline transport to Midwest refineries. In the case of Kern County crude oil, the transport distance was calculated for a California refinery.

Canadian oil sands petroleum is transported by pipeline as diluted bitumen to an upgrader (or potentially an oil refinery). Diluent that is transported to the upgrader is returned to the upgrading site with a return pipeline. Diluent that is transported to the refinery is converted to gasoline. However, there are plans in place to send diluent shipped to the refinery with bitumen back to the bitumen production site. Upgraded SCO is then transported to a Midwest refinery. Refined gasoline and diesel are transported primarily by pipeline to bulk distribution terminals and then delivered to fuel stations by truck.

The GHG emissions associated with crude oil delivery are calculated based on the corresponding transport distances and modes. The emissions are proportional to transport distance although this effect is somewhat mitigated by the effect of crude carrier capacity with the largest most efficient crude carriers hauling crude oil over the longest distances.

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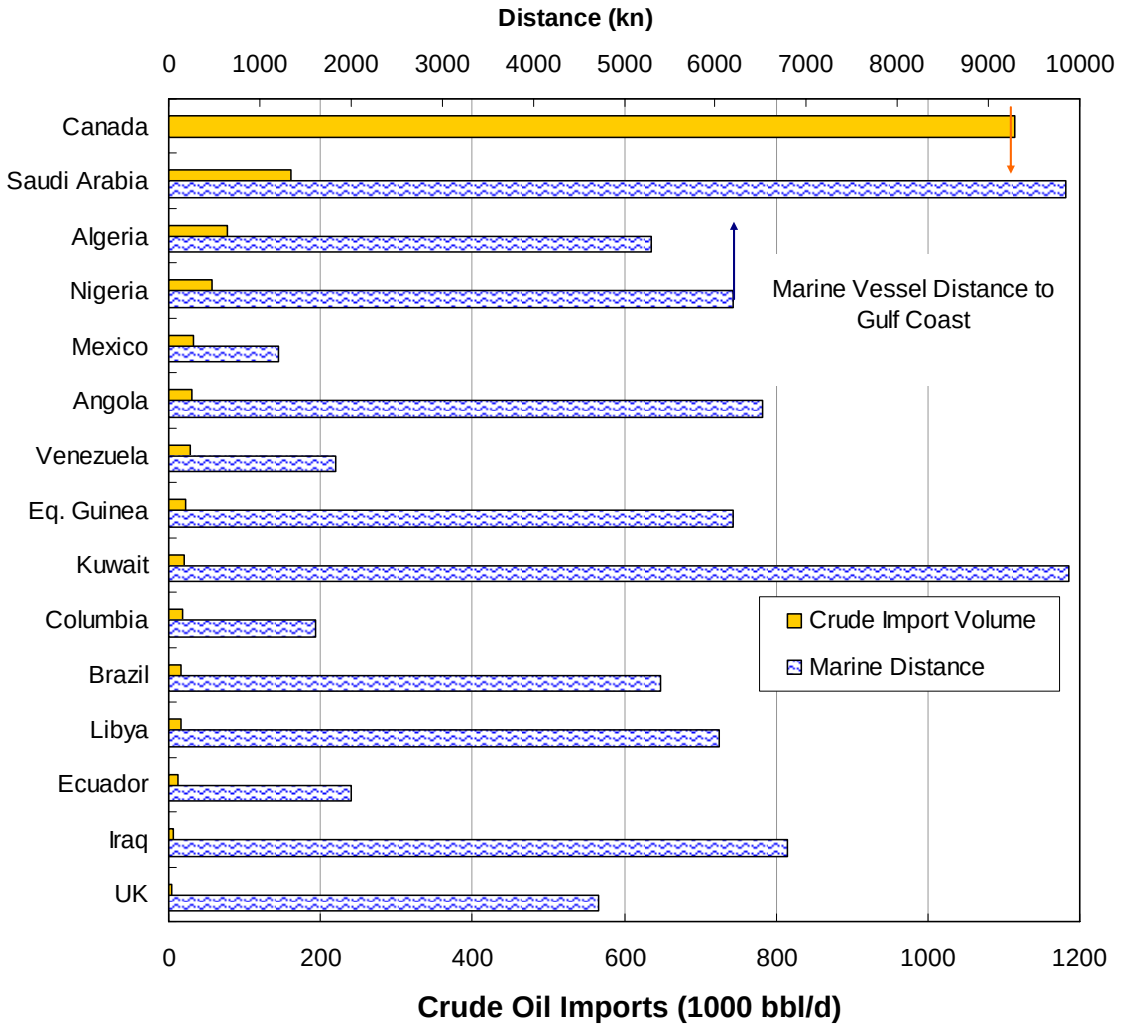
Figure 6-1.
Crude oil imports to PADD 2 and corresponding marine transport distances



An oil tanker is a ship used for the bulk transit of crude oil. Figure 6-2 shows the side view of an oil tanker and points out bridge, fuel tank, engine room, pump room, and double hull as well as oil tanks. Moreover, there are different sizes of tankers categorized by an average freight rate assessment system, called *AFRA scale*, and the flexible market scale. Both scales rate tankers on their deadweight tonnage (DWT). Table 6-1 and Table 6-2 illustrate tanker class and the associated size in DWT of both scales.

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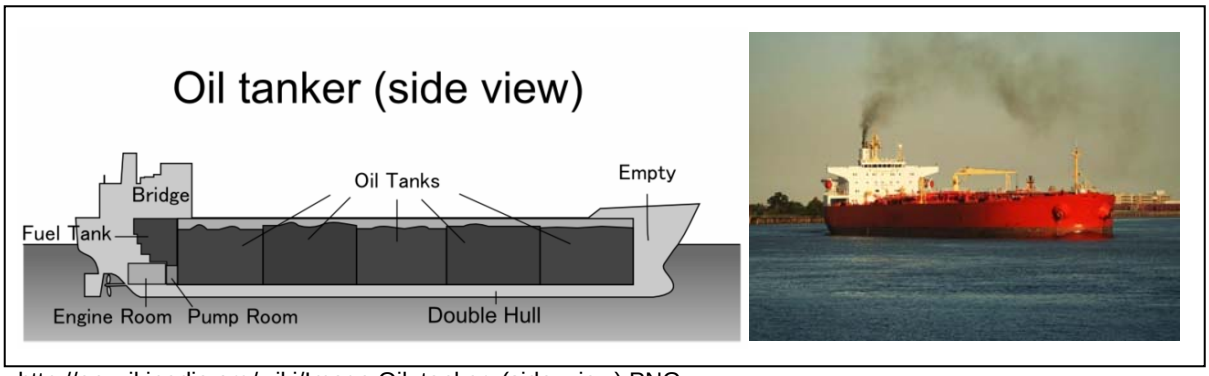
Figure 6-2.
Oil Tanker



http://en.wikipedia.org/wiki/Image:Oil_tanker_(side_view).PNG

Table 6-1.
Oil Tanker Size Categories (AFRA Scale)

Class	Size in DWT
General Purpose Tanker	10,000 – 24,999
Medium Range Tanker	25,000 - 44,999
LR1 (Large Range 1)	45,000 – 79,999
LR2 (Large Range 2)	80,000 – 159,999
VLCC (Very Large Crude Carrier)	160,000 – 319,999
ULCC (Ultra Large Crude Carrier)	320,000 – 549,999

Table 6-2.
Oil Tanker Size Categories (Flexible Market Scale)

Class	Size in DWT
Product Tanker	10,000 – 60,000
Panamax	60,000 – 80,000
Aframax	80,000 – 120,000
Suezmax	120,000 – 200,000
VLCC	200,000 – 320,000
ULCC	320,000 – 550,000

The energy requirements and emissions associated with crude oil transport vary with tanker capacity with the larges crude carries being most efficient. Significant quantities of oil and product are moved in smaller vessels. When the crude oil and product are transported in smaller equipment, the relative GHG emissions grow substantially.

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Transport Distances

The location of the oil field provides the basis for estimating pipeline and marine tanker vessel transport distances. The location of oil fields was determined from industry and economic maps from oil exporting countries, found on various websites. Pipeline distances from oil field to port were generated through Google's distance measurement tool. The ship distances from a foreign port to the Gulf coast are based on online distance, fuel and cost calculator for ship voyages (e-ship). Pipeline distances within the US have been identified by looking at the Crude Oil and Trunk Line System as show in Figure 6-3 below (Allegro Group 2001) and following distance calculations through Google's distance measurement tool. Ocean tanker distances are calculated based on the ship voyager online calculator for distance, fuel and cost for voyages (Figure 6-4, e-ship.net). Transport distances are summarized in Table 6-3.

Figure 6-3.
Selected Crude Oil Truck Line Systems (Allegro Energy Group 2001)

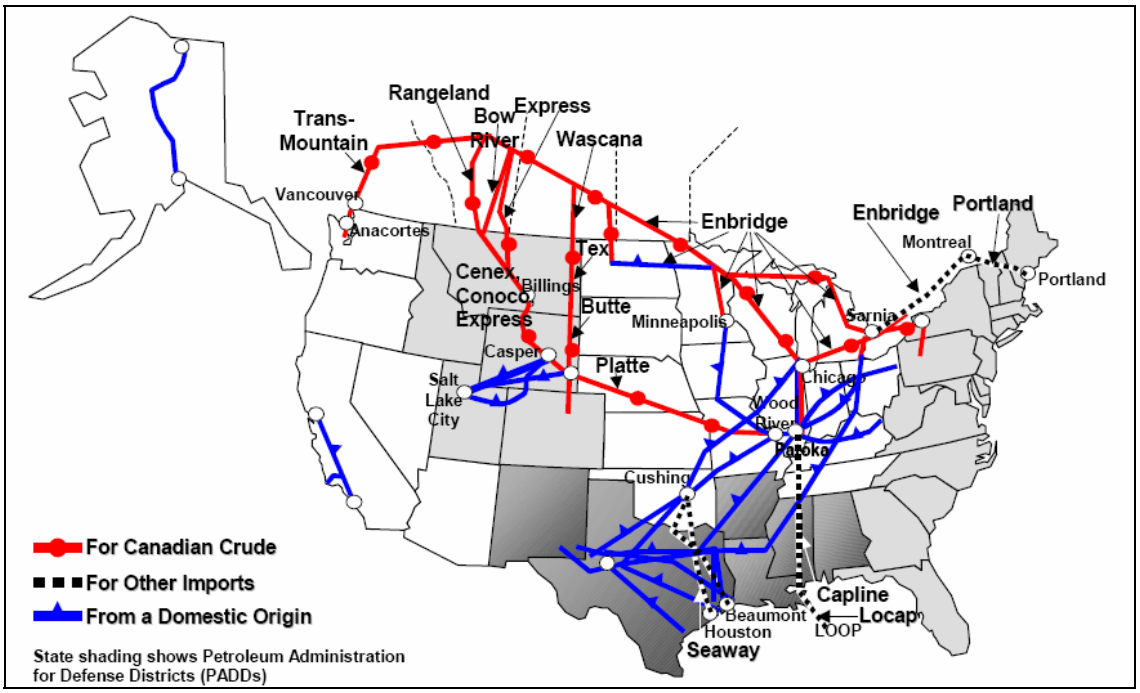

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Figure 6-4.
Screen Shot of Eship Online Calculator for Estimating Ocean Tanker Distances (Eship 2008).

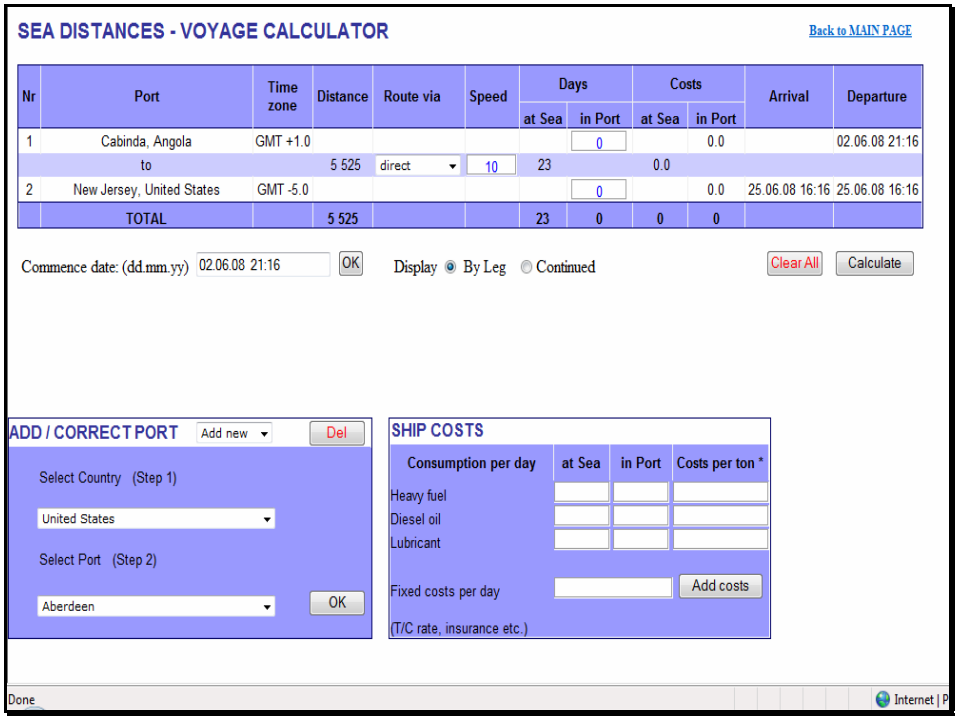

Table 6-3.
Transport Distances for Oil Feedstocks and Products

Feedstock Location	Refinery Location	Marine Transport	Pipeline Transport
<u>Bitumen Transport</u>			
Athabasca	Edmonton	0	91
Edmonton	Chicago	0	1432
Crude Oil Transport			
Venezuela	Chicago	1840	1058
Mars Platform	Chicago	0	448+1058
Saudi Arabia	Chicago	9843 Suez 12,434 Cape of Good Hope	766+1058
Kirkuk	Chicago	6790 Syria	600+1058
Nigeria	Chicago	6194	1058
Bakersfield	Los Angeles	0	102

Transit via Cape Horn allows use of ULCC tankers rather than Suezmax tankers.

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Local Delivery

Finished gasoline and diesel are transported from Midwest refineries largely by pipeline to bulk blending terminals. Finished gasoline and diesel are transported to local fueling stations in truck which generally have a load limit of 80,000 lb Gross Vehicle Weight with either a single or dual trailer configuration (Figure 6-5). This weight limit allows for a truck cargo capacity of 25 metric tons, or 9000 gallons of gasoline which is consistent with GREET calculations. Diesel has a higher volumetric density so only about 8000 gallons are transported in a load. Some fuel is also delivered directly to fuel stations by pipeline, but 100% truck delivery was assumed here.

Figure 6-5.
Gasoline delivery truck

Transport GHG Calculations

PADD 2 Specific Parameters for the Midwest

Oil sands processing includes mode shares and transport calculations for sands transport and bitumen transport in addition to natural gas and electricity distances. These distances are well known via electronic maps and measurement tools. Petroleum flows are more complicated, however, since crude is transported from several difference sources, refined with several other crudes, and then blended with petroleum fuels made in other refineries. Calculating the Midwestern transport shares for the marine and pipeline transport scenarios is straightforward.

Transportation GHG emissions depend on the transportation energy intensity for each mode, transport distance, and the type of fuel used for transportation equipment, which are GREET

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inputs. For each delivery mode, GREET calculates and energy intensity per ton-mile of fuel transport as indicated in Table 6-4. For marine tanker vessels a correlation based on vessel size calculates energy consumption. Loaded and unloaded energy consumption are calculated separately. The fuel for marine tankers is bunker fuel or residual oil with a fuel carbon and upstream GHG emissions based on the default GREET model.

GREET also calculates the energy intensity for pipelines and assumes a mix of pipeline fuels. The same energy intensity is assigned for all pipeline fuels, which will overstate the emissions slightly for electric pipeline transport. Since specific pipeline operations were not investigated in this Study, we the GREET defaults were used for calculating pipeline energy inputs and emissions.

Local fuel delivery is based on a diesel fueled truck. The GREET default for one way delivery distance is 30 miles, while a 50 mile distance is used as a basis for the LCFS. Since this Study focuses on refining products that are used primarily in the Midwest today, the GREET default distance is assumed. Energy intensity is calculated based on an average truck fuel economy of 5 miles per gallon although the outgoing and return energy intensity values are calculated separately in GREET.

Table 6-4.
Crude Oil and Product Transport Calculations

Delivery Mode	Crude Carrie	Pipeline	Delivery Truck
Capacity Africa/ Middle East	200,000 DWT	Pipeline	25 tonne
Fuel	Residual Oil	20% Diesel 50% Residual oil 24% Natural gas 6% Electricity	Diesel
Energy Intensity Outgoing (Btu/ton mi)	29	253	1,028
Energy Intensity Return (Btu/ton mi)	26	--	1,028

GHG emissions associated with crude oil and refined product transport are summarized in Table 6-5. The GHG emissions are based on the average GHG emission intensity values in the GREET model. These values actually change with different crude oil inputs and refinery efficiency assumption in the GREET model. However, since the transport fuel for any specific crude oil is not tied to the refinery configuration, and the GREET average values are used here. The upstream GHG intensity of the transport fuels is about 25% of the total emissions associated with fuel transport.

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Table 6-5.
Transport GHG Emissions per crude location to Midwestern PADD 2

Feedstock Location	GHG Emissions (g GHG/MJ product)
Crude Oil Transport	
Edmonton	0.94
Venezuela	0.96
Maya Platform	0.96
Mars Platform	0.98
Saudi Arabia	2.44
Kirkuk	2.09
Nigeria, Bonny	1.60
Bakersfield	0.07
Product Distribution	
Pipeline and Truck	0.42

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Section 7.

Vehicle Emissions

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The final stage of the fuel cycle considered in this study is the vehicle, which is the TTW stage of the process. Vehicle emissions include CO_2, CO, VOC, and CH_4, as well as N_2O combustion products. The carbon-containing constituents are derived from the fuel while N_2O is based on the thermal conversion of atmospheric nitrogen. In our LCA analysis, only the CO_2, CH_4 and N_2O emissions are considered in calculating GHG emissions.

The vehicle or TTW emissions are separately treated in the life cycle analysis of fuels. In the GREET model. these emissions can also be represented on a per unit of fuel basis as illustrated in Table 7-1. Here the emissions are divided by the vehicle fuel consumption and represented on a g/MJ basis.

Because criteria pollutants such as NO_x are regulated on a per mile basis, the per MJ representation may skew the scaling of the emission factor if vehicle technology changes significantly. However, the representation on a per MJ basis provides a convenient metric for counting all of the emissions in the fuel cycle. As shown in the table, the value for diesel trucks from ARB's EMFAC model are comparable to the passenger car values from GREET when compared on per MJ basis. Furthermore, the notion that N_2O emissions are strictly constants with vehicle mileage is not demonstrated by vehicle test data. The same metric is used by the CA LCFS. The emission factors shown here represent the current mix of gasoline passenger cars and heavy-duty diesel trucks (ARB). The IPCC designated global warming potential factors, shown in Table 2.2 of Section 2, are used to convert emissions of CH_4 and N_2O into a CO_2 equivalent, global warming potential basis.

Table 7-1.
TTW Calculations of CH_4 and N_2O Emissions

Fuel	Gasoline	Gasoline	Diesel	Diesel
Source	LCFS	GREET1.8c	LCFS	GREET1.8c
Vehicle	Vehicle Mix	Passenger Car		Passenger Car
Fuel Economy (mi/gal)	19.2	23.4	6.1	28.1
Fuel Economy (MJ/mi)	6.2	5.1	19.4	4.8
Exhaust Emissions (g/mi)				
CH_4	0.039	0.0146	0.035	0.026
N_2O	0.014	0.012	0.048	0.012
GWP Weighted (g/MJ)				
CH_4	0.16	0.071	0.045	0.014
N_2O	0.66	0.70	0.735	0.75
Total	0.82	0.77	0.78	0.76

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The values used in the LCFS differ from the GREET default values because the LCFS values represent a mix of vehicles. Also, the CH_4 and N_2O emissions are derived from different emission inventory models. The LCFS values were used in this study.

Table 7-2 shows the vehicle emissions for different vehicle/fuel technologies. The carbon content varies by the fuels. The fuel properties are from the GREET model used for the CA LCFS. The fuel density and carbon content values are adjusted slightly from the GREET defaults based on inputs from oil refiners (TIAX).

Vehicle CO_2 is represented as the fuels carbon content as CO_2 divided by the lower heating value of the fuel. Vehicle fuel carbon is primarily emitted as CO_2 with less than 1% converted to hydrocarbons, CO, CH_4, and particulate matter. The GHG accounting used here represents all of the hydrocarbon and CO emissions as CO_2 because these pollutants are converted to CO_2 in the atmosphere in a matter of days. Since a GWP is applied to CH_4 emissions, the carbon in the CH_4 is not counted twice and subtracted from the total CO_2 emissions (this effect is only 0.02 gCO_2/MJ).

Table 7-2.
Fuel Carbon Content and Vehicle Emissions

Fuel	Conventional Gasoline	RBOB/ CARBOB	ULSD
Carbon Content	86.3%	85.9%	86.5%
LHV (Btu/gal)	116,090	113,300	127,464
LHV (MJ/gal)	122.5	119.5	134.5
Density (g/gal)	2,819	2,767	3,142
Carbon Factor			
(g/mmBtu) as CO_2	76,839	76,921	78,179
(g/MJ) as CO_2 - CH_4	72.8	72.9	74.1
Vehicle CH_4 & N_2O (g/MJ)	0.8	0.8	0.8

Reference: (CA_GREET_1.8b April 2009)

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References

ARB (California Air Resources Board)

- *Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG)*, California Air Resources Board, Stationary Source Division Release Date: February 27, 2009, Version: 2.1.

- *Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California*, California Air Resources Board, Stationary Source Division Release Date: February 28, 2009, Version: 2.1.

TIAX, *Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts*, California Energy Commission Report CEC-600-2007-002-D, February 2007.

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Section 8.

Life Cycle Assessment

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The energy inputs, conversion yields, coproducts, and product losses are taken into account in calculating GHG emissions over the life cycle of petroleum, bitumen and heavy oil. This Study follows the framework of the GREET model but uses an external calculation that develops the full fuel cycle analysis of petroleum based on the steps in the fuel cycle. Emissions from each step in converting crude oil or bitumen to transportation fuels are summed taking into account conversion yields. The steps were shown in Figure 1-2 of Section 1 and are outlined below.

Table 8-1.
Steps in WTW Lifecycle Assessment for Converting Crude and Bitumen to Transport Fuels

Crude	Bitumen	
To Refining	**To Upgrading**	**To Refining**
Crude production	Bitumen Production	Bitumen Production
	Transport to Upgrader	
	Upgrade to SCO	
Crude transport to the refinery	SCO transport to the refinery	Bitumen transport to the refinery with diluent
Refining	Refining	Refining – diluent refined or returned to production site
Delivery of fuels to tank of vehicle	Delivery of fuels to tank of vehicle	Delivery of fuels to tank of vehicle
Combustion of fuel in vehicle	Combustion of fuel in vehicle	Combustion of fuel in vehicle

The conversion yield for each crude oil type affects the upstream processing steps. In this Study, the quantities of SCO produced from upgraders as well as the amount of product produced from refineries are used to determined the amount of total crude oil and bitumen feedstock as well as the oil transport energy required per MJ of gasoline or diesel product.

In addition to tracking GHG emissions from these steps, the feeds brought in and used at each point in the life cycle analysis were tracked to account for the GHG emissions for producing each feed. Thus, the amount of crude oil was tracked to the refinery products C3, C4, CBOB, RBOB, ULSD, coke and sulfur to make sure that each received its proper share of the energy needed and GHG emitted in producing and converting crude oil and bitumen to products. The amount of isobutane used in the refinery alkylation unit was also tracked to ensure that gasoline (but not diesel) received the proper distribution of energy and GHG used to for producing the isobutane. The amount of isobutane used in CBOB and RBOB production varies depending on

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their alkylate content. In the upgrader, the amounts of bitumen and diluent used were tracked to the products SCO, coke, and sulfur.

The natural gas, electricity, and other energy brought in to each step in the life cycle WTW were portioned to the products so that the GHG burden for producing this energy is properly attributed. The energy was tracked not only for producing the crude oil and bitumen and the energy to refine them, but also for transporting the crude oil and bitumen to the refinery and distributing the products from the refinery.

In this LCA study, the GHG burdens that were distributed to the coproducts are redistributed to the major products. Thus, the burden for producing refinery C3, C4, coke, and sulfur were distributed to CBOB, RBOB, and ULSD. The upgrader burden for producing sulfur and coke was distributed to SCO.

Another coproduct burden must also be included. Because many coproducts are used as substitutes for other products, the difference in life cycle emissions between making and using these coproducts vs. the products they replace must be accounted for. The difference is added back to the main products—either SCO from the upgrader or CBOB, RBOB, and ULSD from the refinery.

Coke is the first coproduct that must be considered. Coke from the upgrader is assumed to be stored and not used as a fuel. However, coke from the refinery is assumed to be used as a substitute for coal in electricity generation. Thus, the lifecycle difference between using coke instead of coal must be accounted for. A small difference in shipping coal vs. coke to the power plant was assumed. It is also necessary to account for the difference in burning coke instead of coal in a power plant. Factors from the EIA, shown in Table 8-2, were used to account for the differences in the heat content and GHG emissions between coal and coke.

Table 8-2.
Heating Value of Coal and Petroleum Coke

Coke Heating Value	GJ/Klb	15.88
Carbon Coefficient—Refinery Coke	g GHG/MJ	96.8
Carbon Coefficient—Coal	g GHG/MJ	88.6

EIA

The best way to show the roll-up of GHG emissions is with an example. Three will be used. The first shows production and refining of Arab Medium crude. The second shows bitumen production by SAGD, converting it to SCO in a coker-based upgrader, and then refining the SCO in a refinery The third example shows bitumen production via SAGD, shipping it with

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diluent to a refinery, refining the bitumen and sending the diluent back to the bitumen production site.

Life Cycle Assessment—Arab Medium Crude

WTW GHG emissions for producing CBOB, RBOB and ULSD from Arab Medium crude are shown in Table 8-3. The table can be broken down into two sections. Rates for crude and the products CBOB, RBOB, and ULSD are at the top of the left-hand side of the table. Below are the GHG emissions in Metric Tonnes per Day (MTD) for each processing step in the WTW.

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Table 8-3.
Life Cycle Assessment of WTW GHG Emissions for Arab-Medium Crude to Refined Products

		Rates				GHG Intensity			
		Crude	**CBOB**	**RBOB**	**ULSD**	**Crude**	**CBOB**	**RBOB**	**ULSD**
Rate	BPSD	140,000	51,108	35,000	44,147				
Heating Value	GJ/Bbl	5.76	5.04	5.16	5.84				
Emissions		GHG, MTD	GHG, MTD	GHG, MTD	GHG, MTD	g/MJ	g/MJ	g/MJ	g/MJ
Total WTTW Emissions							**98.8**	**98.3**	**98.2**
Vehicle CH4, N2O							**0.8**	**0.8**	**0.8**
Carbon in Fuel							**72.8**	**72.9**	**74.1**
Total GHG		**16,916**	**6,472**	**4,443**	**6,008**	**21.0**	**25.1**	**24.6**	**23.3**
Oil Production		**3,505**	**1,297**	**909**	**1,299**	**4.3**	**5.0**	**5.0**	**5.0**
Production GHG		2,918	1,080	757	1,081	3.6	4.2	4.2	4.2
Venting and Flaring GHG		587	217	152	218	0.7	0.8	0.8	0.8
Oil Transport		**1,963**	**726**	**509**	**727**	**2.4**	**2.8**	**2.8**	**2.8**
Refining - Major Products with Co-Products		**8,897**	**3,454**	**2,320**	**3,123**	**11.0**	**13.4**	**12.9**	**12.1**
GHG of Major Product		8,234	3,208	2,149	2,877	10.2	12.5	11.9	11.2
C3 - Refining GHG to Major Products		144	53	37	53	0.2	0.2	0.2	0.2
C4 - Refining GHG to Major Products		89	33	23	33	0.1	0.1	0.1	0.1
Coke - Refining GHG to Major Products		198	73	51	73	0.2	0.3	0.3	0.3
Sulfur - Refining GHG to Major Products		232	86	60	86	0.3	0.3	0.3	0.3
Delivery		**294**	**109**	**76**	**109**	**0.4**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**1,997**	**764**	**534**	**699**	**2.5**	**3.0**	**3.0**	**2.7**
Natural Gas - Upstream GHG to Major Products		417	130	78	209	0.5	0.5	0.4	0.8
Electricity - Upstream GHG to Major Products		1,579	634	456	490	2.0	2.5	2.5	1.9
Other Feeds		**123**	**71**	**57**	**0**	**0.2**	**0.3**	**0.3**	**0.0**
Isobutane for Alkylation - Upstream GHG to Major Products		123	71	57	0	0.2	0.3	0.3	0.0
Impact of Replacing Coal with Refinery Pet Coke		**139**	**51**	**36**	**51**	**0.2**	**0.2**	**0.2**	**0.2**

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The right-hand side of Table 8-3 shows the GHG intensity for each product reported as g GHG/MJ of fuel. Included in this section are the TTW emissions from the vehicle, which are N_2O, CH_4, and CO_2 from combusting carbon in the fuel. All are reported on a CO_2 equivalent (GHG) basis which accounts for their global warming potential.

The major categories of emissions correspond to the major steps in the life cycle analysis.

- Total GHG is the sum of the major emissions from crude oil production, oil transport, refining, delivery of refined products to the vehicle tank, and emissions from combustion of the fuel on the vehicle. There are several other categories also shown in Table 8-3—fuel cycle, other feeds, and the impact of replacing coal from coke—that will be discussed.
- In Table 8-3, the total GHG emissions for crude oil production are 3,505 MTD, which is broken down into 2,918 MTD for the actual production and 587 MTD for venting and flaring. These values are based on factors from the Crude Production section (Figure 3-8 of the Crude Production Section) that were calculated using the crude production model and input from Table 3-11. For the production of Arab-Medium there are 3.6 g GHG/MJ of crude from production and 0.7 g GHG/MJ from venting and flaring releases. These GHG emissions are distributed to RBOB, CBOB, and ULSD based on the content of crude in each product.
- The 1963 MTD of GHG emissions for oil transport shown in Table 8-3 are based on factors from GREET modified by the distance for transporting Arab-Medium crude to the refinery discussed in section titled Transport and Delivery (Section 6). Distribution of the transport GHG emissions to CBOB, RBOB and ULSD is based on the content of crude in each product.
- GHG emissions from the refining of 140 KBPD of Arab-Medium are 8,897 MTD. These emissions are also shown in Table 5-16 of the Crude Refining section in the row marked "Total GHG Emissions before Adding Upstream Burden." The breakdown of refining burden to RBOB, CBOB, and ULSD in Table 8-3 shows the total to each product, including the distribution from production of the coproducts, C3, C4, sulfur, and coke.
- Delivery of refined products to the tank of the vehicle is 294 MTD and is based on factors described earlier from GREET.
- Fuel cycle emissions represent the GHG emissions to produce the natural gas and electricity used in producing the oil, shipping it, refining it, and distributing the products. Natural gas is used in oil production to supplement the associated gas used in power generation. Natural gas is used in refining to supplement the fuel gas and to supply feed to the hydrogen plant. In this analysis, electricity is imported for refining but generated

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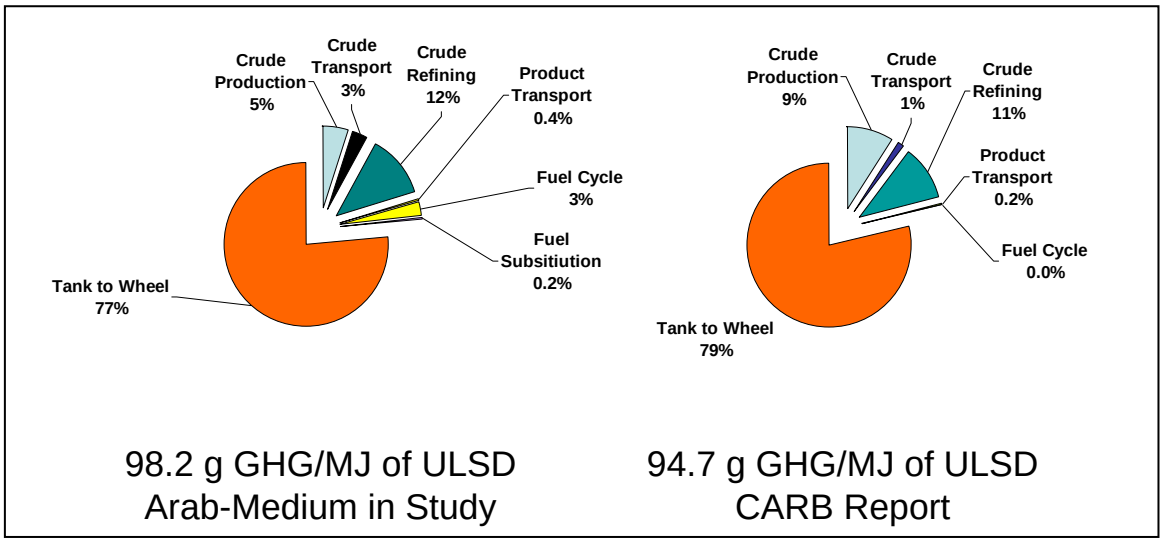
from associated gas and natural gas in oil production. The upgraders also generate electricity from natural gas and do not import electric power from the grid. This means that electric power used in the upgraders has a natural gas GHG burden associated with it, not the Alberta grid electricity mix. Note that in this analysis, the fuel cycle emissions from producing the energy used in transport of crude to the refinery and delivery of products to the vehicle tank have been ignored. This assumption means that the WTW GHG emissions for Arab-Medium are 0.5-1% low. For crudes with less travel, the impact of ignoring transport and delivery fuel cycle emissions will be smaller.

- Other feeds include the energy to produce isobutane for alkylation, which is assumed to be the same as for producing natural gas because much of the isobutane used in refining comes from natural gas production.

The right-hand side of Table 8-3 shows the GHG intensity for each step as g GHG/MJ of fuel. The TTW portion attributable to fuel use in the vehicle included here is from GREET. The vehicle contributions are different for gasoline and diesel.

The WTW analysis shows 98.8 g GHG/MJ of CBOB, 98.3 g GHG/MJ for RBOB, and 98.2 g GHG/MJ for producing ULSD. Figure 8-1 compares GHG emissions for producing ULSD from Arab-Medium in this study vs. the GHG emissions reported to make ULSD in a recent CARB report *(Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California*, CARB, February 28, 2009).

Figure 8-1.
WTW GHG Emissions for Producing ULSD



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Note that the results in the CARB report show lower emissions and do not include the fuel cycle effect or the effect of substituting refinery coke for coal in electric power production. Adding the fuel cycle emissions to the CARB results brings the emissions for the two studies closer together in terms of total GHG emissions.

It is important to again note that while the TTW emissions are assumed to be independent of crude, the WTT emissions very much depend on how the crude was produced, shipped and refined. Results in Table 8-4 show the variation in WTW emissions for several conventional crudes. This table also shows the differences in contribution to overall GHG emissions from the steps in the WTTW process.

Table 8-4.
WTW GHG Emissions for ULSD from Conventional Crudes

		Bachaquero	Maya	Arab Medium	Mars	Bonny Light	Kirkuk
Total WTTW Emissions	g GHG/MJ	100.2	102.5	98.2	103.5	106.9	102.1
Vehicle CH4, N2O	% of Total	0.8	0.8	0.8	0.8	0.7	0.8
Carbon in Fuel	% of Total	73.9	72.3	75.5	71.6	69.3	72.6
Oil Production	% of Total	6.0	8.8	5.1	11.4	15.7	9.9
Oil Transport	% of Total	1.2	1.2	2.9	1.1	1.6	2.3
Refining - Upstream GHG to Major Product	% of Total	14.0	12.8	12.3	11.6	9.9	11.3
Delivery	% of Total	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Cycle	% of Total	3.1	3.3	2.8	3.0	2.3	2.6
Impact of Replacing Coal with Refinery Pet Coke	% of Total	0.5	0.4	0.2	0.2	0.0	0.1

Life Cycle Assessment—SCO from Bitumen

Table 8-5 shows emissions from producing bitumen by SAGD, converting the bitumen to SCO in a coker-based upgrader, and refining the resulting SCO. This example includes the emissions from transporting bitumen to the upgrader and from producing SCO. The SCO emissions include the distribution of emissions for removing diluent from the bitumen, from producing the coproducts coke and sulfur, and for producing SCO. The emissions from producing SCO are distributed to CBOB, RBOB, and ULSD depending on the amount of SCO used to make each product. Natural gas-fired cogen supplies some of the steam and all of the power to the upgrader.

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Life Cycle Assessment—Bitumen

Table 8-6 shows emissions from producing bitumen by SAGD, transporting dilbit to the refinery, separating diluent from bitumen, returning the diluent to the production site, and refining bitumen to CBOB, RBOB, and ULSD. This example includes the energy to ship diluent back to the production site.

Life Cycle Assessment—All Study Crudes and Bitumen

The WTW GHG emissions for all the crudes and bitumen processed in this Study are shown in Tables 8-7 through 8-9 for RBOB, CBOB and ULSD, respectively. A graphical example of the results is shown in Figure 8-2 for RBOB, which is a low vapor pressure gasoline blend ready for addition of up to 10 vol-% ethanol.

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Table 8-5.
Life Cycle Assessment of WTW GHG Emissions for SAGD Produced Bitumen via Coking-Based Upgrader to Refined Products

		Rates				GHG Intensity			
		Crude	**CBOB**	**RBOB**	**ULSD**	**Crude**	**CBOB**	**RBOB**	**ULSD**
Rate	BPSD	161,442	63,159	35,000	49,824				
Heating Value	GJ/Bbl	6.30	5.10	5.19	5.88				
Emissions		GHG, MTD	GHG, MTD	GHG, MTD	GHG, MTD	g/MJ	g/MJ	g/MJ	g/MJ
Total WTTW Emissions							**115.7**	**116.1**	**112.7**
Vehicle CH4, N2O							**0.8**	**0.8**	**0.8**
Carbon in Fuel							**72.8**	**72.9**	**74.1**
Total GHG		**32,307**	**13,547**	**7,705**	**11,064**	**31.7**	**42.1**	**42.5**	**37.8**
Oil Production		**11,313**	**4,573**	**2,579**	**4,161**	**11.1**	**14.2**	**14.2**	**14.2**
Production GHG		11,313	4,573	2,579	4,161	11.1	14.2	14.2	14.2
Venting and Flaring GHG		0	0	0	0	0.0	0.0	0.0	0.0
Oil Transport		**68**	**27**	**15**	**25**	**0.1**	**0.1**	**0.1**	**0.1**
Upgrading		**6,884**	**2,783**	**1,569**	**2,532**	6.8	8.6	8.6	8.6
SCO		5,810	2,348	1,324	2,137	5.7	7.3	7.3	7.3
Coke - Upgrading GHG to Major Products		440	178	100	162	0.4	0.6	0.6	0.6
Sulfur - Upgrading GHG to Major Products		292	118	67	108	0.3	0.4	0.4	0.4
Diluent Return - Upgrading GHG to Major Products		342	138	78	126	0.3	0.4	0.4	0.4
SCO Transport		**774**	**313**	**177**	**285**	0.8	1.0	1.0	1.0
Refining - Major Products with Co-Products		**8,890**	**3,998**	**2,294**	**2,598**	**8.7**	**12.4**	**12.6**	**8.9**
GHG of Major Product		8,525	3,851	2,211	2,464	8.4	12.0	12.2	8.4
C3 - Refining GHG to Major Products		146	59	33	54	0.1	0.2	0.2	0.2
C4 - Refining GHG to Major Products		59	24	13	22	0.1	0.1	0.1	0.1
Coke - Refining GHG to Major Products		5	2	1	2	0.0	0.0	0.0	0.0
Sulfur - Refining GHG to Major Products		155	63	35	57	0.2	0.2	0.2	0.2
Delivery		**336**	**136**	**77**	**124**	**0.3**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**3,855**	**1,605**	**912**	**1,339**	**3.8**	**5.0**	**5.0**	**4.6**
Natural Gas - Upstream GHG to Major Products		2,290	923	519	849	2.3	2.9	2.9	2.9
Electricity - Upstream GHG to Major Products		1,565	681	393	491	1.5	2.1	2.2	1.7
Other Feeds		**186**	**113**	**82**	**0**	**0.2**	**0.3**	**0.5**	**0.0**
Isobutane for Alkylation - Upstream GHG to Major Products		186	113	82	0	0.2	0.3	0.5	0.0
Impact of Replacing Coal with Refinery Pet Coke		**1**	**0**	**0**	**0**	**0.0**	**0.0**	**0.0**	**0.0**

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Table 8-6.
Life Cycle Assessment of WTW GHG Emissions for Bitumen via Dilbit to Refined Products—with Diluent Return

		Rates				GHG Intensity			
		Crude	**CBOB**	**RBOB**	**ULSD**	**Crude**	**CBOB**	**RBOB**	**ULSD**
Rate	BPSD	140,000	53,183	35,000	45,715				
Heating Value	GJ/Bbl	6.30	5.01	5.08	5.79				
Emissions		GHG, MTD	GHG, MTD	GHG, MTD	GHG, MTD	g/MJ	g/MJ	g/MJ	g/MJ
Total WTTW Emissions							**113.3**	**113.1**	**111.2**
Vehicle CH4, N2O							**0.8**	**0.8**	**0.8**
Carbon in Fuel							**72.8**	**72.9**	**74.1**
Total GHG		**27,139**	**10,562**	**7,009**	**9,602**	**30.7**	**39.7**	**39.4**	**36.3**
Oil Production		**9,810**	**3,686**	**2,461**	**3,663**	**11.1**	**13.8**	**13.8**	**13.8**
Production GHG		9,810	3,686	2,461	3,663	11.1	13.8	13.8	13.8
Venting and Flaring GHG		0	0	0	0	0.0	0.0	0.0	0.0
Oil Transport		**825**	**310**	**207**	**308**	**0.9**	**1.2**	**1.2**	**1.2**
Diluent Recycle		**524**	**197**	**131**	**196**	0.6	0.7	0.7	0.7
Refining - Major Products with Co-Products		**11,571**	**4,589**	**3,067**	**3,915**	**13.1**	**17.2**	**17.2**	**14.8**
GHG of Major Product		10,395	4,147	2,772	3,476	11.8	15.6	15.6	13.1
C3 - Refining GHG to Major Products		262	98	66	98	0.3	0.4	0.4	0.4
C4 - Refining GHG to Major Products		62	23	16	23	0.1	0.1	0.1	0.1
Coke - Refining GHG to Major Products		490	184	123	183	0.6	0.7	0.7	0.7
Sulfur - Refining GHG to Major Products		362	136	91	135	0.4	0.5	0.5	0.5
Delivery		**299**	**112**	**75**	**112**	**0.3**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**3,493**	**1,319**	**889**	**1,285**	**4.0**	**5.0**	**5.0**	**4.9**
Natural Gas - Upstream GHG to Major Products		1,733	624	419	691	2.0	2.3	2.4	2.6
Electricity - Upstream GHG to Major Products		1,759	695	470	594	2.0	2.6	2.6	2.2
Other Feeds		**285**	**224**	**95**	**0**	**0.3**	**0.8**	**0.5**	**0.0**
Isobutane for Alkylation - Upstream GHG to Major Products		285	224	95	0	0.3	0.8	0.5	0.0
Impact of Replacing Coal with Refinery Pet Coke		**332**	**125**	**83**	**124**	**0.4**	**0.5**	**0.5**	**0.5**

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Table 8-7.
Life Cycle Assessment of GHG Emissions for Crude and Bitumen to RBOB

Lifecycle Assesment of GHG Emissions		Bachaquero	Maya	Arab Medium	Mars	Bonny Light	Kirkuk Blend	CA TEOR	SAGD SCO - Ckr	SAGD SCO - Eb-Bed	SAGD Bitumen	Dilbit	Mining SCO - Ckr	Mining Bitumen
		RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB	RBOB
Rate	BPSD	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Heating Value	GJ/Bbl	5.23	5.16	5.16	5.15	5.34	5.18	5.22	5.19	5.19	5.08	5.02	5.19	5.08
Emissions		g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ
Total WTW Emissions		**101.9**	**102.1**	**98.3**	**103.9**	**106.4**	**101.7**	**114.2**	**116.1**	**118.9**	**113.1**	**105.4**	**108.2**	**105.4**
Vehicle CH4, N2O		**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Carbon in Fuel		**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**	**72.9**
Total WTT GHG Emissions		**28.2**	**28.4**	**24.6**	**30.2**	**32.7**	**28.0**	**40.5**	**42.5**	**45.2**	**39.4**	**31.7**	**34.5**	**31.7**
Oil Production		**6.1**	**9.0**	**5.0**	**11.8**	**16.8**	**10.1**	**18.9**	**14.2**	**12.6**	**13.8**	**9.6**	**7.3**	**7.1**
Production GHG		5.0	8.4	4.2	10.8	4.8	4.6	18.9	14.2	12.6	13.8	9.6	7.3	7.1
Venting and Flaring GHG		1.0	0.6	0.8	1.0	12.0	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Transport		**1.2**	**1.2**	**2.8**	**1.1**	**1.7**	**2.3**	**0.1**	**0.1**	**0.1**	**1.2**	**1.1**	**0.1**	**1.2**
Diluent Recycle		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**0.0**	**0.0**	**0.7**
Upgrading		0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.6	11.6	0.0	0.0	8.6	0.0
SCO		0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	10.8	0.0	0.0	7.3	0.0
Coke - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.6	0.0
Sulfur - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
Diluent Return - Upgrading GHG to Major Product		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
SCO Transport		0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.1	0.0	0.0	1.0	0.0
Refining - Upstream GHG to Major Product		**16.2**	**13.5**	**12.9**	**13.1**	**10.8**	**11.8**	**15.7**	**12.6**	**13.4**	**17.2**	**14.7**	**12.6**	**17.2**
GHG of Major Product		14.8	12.1	11.9	12.3	10.4	11.1	14.6	12.2	12.6	15.6	13.6	12.2	15.6
C3 - Upstream GHG to Major Product		0.3	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.4	0.3	0.2	0.4
C4 - Upstream GHG to Major Product		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coke - Upstream GHG to Major Product		0.7	0.6	0.3	0.2	0.1	0.2	0.5	0.0	0.4	0.7	0.4	0.0	0.7
Sulfur - Upstream GHG to Major Product		0.4	0.4	0.3	0.3	0.2	0.3	0.3	0.2	0.2	0.5	0.4	0.2	0.5
Delivery		**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**3.2**	**3.4**	**3.0**	**3.3**	**2.7**	**2.9**	**4.5**	**5.0**	**5.3**	**5.0**	**4.2**	**4.0**	**4.0**
Natural Gas - Upstream GHG to Major Product		0.7	0.9	0.4	0.8	0.3	0.4	3.1	2.9	3.1	2.4	1.8	1.9	1.4
Electricity - Upstream GHG to Major Product		2.5	2.6	2.5	2.4	2.4	2.5	1.4	2.2	2.2	2.6	2.4	2.2	2.6
Other Feeds		**0.6**	**0.4**	**0.3**	**0.3**	**0.2**	**0.2**	**0.5**	**0.5**	**0.5**	**0.5**	**1.5**	**0.5**	**0.5**
Diluent in Dilbit		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0
Isobutane for Alkylation - Upstream GHG to Major Product		0.6	0.4	0.3	0.3	0.2	0.2	0.5	0.5	0.5	0.5	0.6	0.5	0.5
Impact of Replacing Coal with Refinery Pet Coke		**0.5**	**0.4**	**0.2**	**0.2**	**0.0**	**0.1**	**0.3**	**0.0**	**0.2**	**0.5**	**0.3**	**0.0**	**0.5**

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Table 8-8.
Life Cycle Assessment of WTW GHG Emissions for Crude and Bitumen to CBOB

Lifecycle Assesment of GHG Emissions		Bachaquero	Maya	Arab Medium	Mars	Bonny Light	Kirkuk Blend	CA TEOR	SAGD SCO - Ckr	SAGD SCO - Eb-Bed	SAGD Bitumen	Dilbit	Mining SCO - Ckr	Mining Bitumen
		CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB	CBOB
Rate	BPSD	40,746	43,965	51,108	52,892	46,162	54,184	40,263	63,159	57,356	53,183	70,688	63,159	53,183
Heating Value	GJ/Bbl	5.18	5.08	5.04	5.09	5.18	5.03	5.30	5.10	5.11	5.01	4.98	5.10	5.01
Emissions		g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ
Total WTW Emissions		**101.7**	**102.2**	**98.8**	**103.1**	**106.8**	**102.2**	**113.5**	**115.7**	**118.5**	**113.3**	**108.1**	**107.8**	**105.5**
Vehicle CH4, N2O		**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Carbon in Fuel		**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**	**72.8**
Total WTT GHG Emissions		**28.1**	**28.6**	**25.1**	**29.4**	**33.1**	**28.5**	**39.9**	**42.1**	**44.9**	**39.7**	**34.5**	**34.2**	**31.9**
Oil Production		**6.1**	**9.0**	**5.0**	**11.8**	**16.8**	**10.1**	**18.9**	**14.2**	**12.6**	**13.8**	**9.6**	**7.3**	**7.1**
Production GHG		5.0	8.4	4.2	10.8	4.8	4.6	18.9	14.2	12.6	13.8	9.6	7.3	7.1
Venting and Flaring GHG		1.0	0.6	0.8	1.0	12.0	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Transport		**1.2**	**1.2**	**2.8**	**1.1**	**1.7**	**2.3**	**0.1**	**0.1**	**0.1**	**1.2**	**1.1**	**0.1**	**1.2**
Diluent Recycle		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**0.0**	**0.0**	**0.7**
Upgrading		0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.6	11.6	0.0	0.0	8.6	0.0
SCO		0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	10.8	0.0	0.0	7.3	0.0
Coke - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.6	0.0
Sulfur - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
Diluent Return - Upgrading GHG to Major Product		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
SCO Transport		0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.1	0.0	0.0	1.0	0.0
Refining - Upstream GHG to Major Product		**16.2**	**13.7**	**13.4**	**12.5**	**11.3**	**12.4**	**15.1**	**12.4**	**13.3**	**17.2**	**13.9**	**12.4**	**17.2**
GHG of Major Product		14.7	12.4	12.5	11.7	10.9	11.6	14.1	12.0	12.4	15.6	12.8	12.0	15.6
C3 - Upstream GHG to Major Product		0.3	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.4	0.3	0.2	0.4
C4 - Upstream GHG to Major Product		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coke - Upstream GHG to Major Product		0.7	0.6	0.3	0.2	0.1	0.2	0.5	0.0	0.4	0.7	0.4	0.0	0.7
Sulfur - Upstream GHG to Major Product		0.4	0.4	0.3	0.3	0.2	0.3	0.3	0.2	0.2	0.5	0.4	0.2	0.5
Delivery		**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**3.2**	**3.4**	**3.0**	**3.3**	**2.7**	**2.9**	**4.6**	**5.0**	**5.2**	**5.0**	**4.1**	**4.0**	**4.0**
Natural Gas - Upstream GHG to Major Product		0.7	0.9	0.5	0.8	0.4	0.5	3.1	2.9	3.1	2.3	1.7	1.9	1.4
Electricity - Upstream GHG to Major Product		2.5	2.5	2.5	2.4	2.3	2.4	1.5	2.1	2.1	2.6	2.4	2.1	2.6
Other Feeds		**0.6**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.4**	**0.3**	**0.4**	**0.8**	**5.1**	**0.3**	**0.8**
Diluent in Dilbit		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0	0.0
Isobutane for Alkylation - Upstream GHG to Major Product		0.6	0.3	0.3	0.2	0.2	0.2	0.4	0.3	0.4	0.8	0.4	0.3	0.8
Impact of Replacing Coal with Refinery Pet Coke		**0.5**	**0.4**	**0.2**	**0.2**	**0.0**	**0.1**	**0.3**	**0.0**	**0.2**	**0.5**	**0.3**	**0.0**	**0.5**

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Table 8-9.
Life Cycle Assessment of WTW GHG Emissions for Crude and Bitumen to ULSD

Lifecycle Assesment of GHG Emissions		Bachaquero	Maya	Arab Medium	Mars	Bonny Light	Kirkuk Blend	CA TEOR	SAGD SCO - Ckr	SAGD SCO - Eb-Bed	SAGD Bitumen	Dilbit	Mining SCO - Ckr	Mining Bitumen
		ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
Rate	BPSD	52,478	44,034	44,147	44,812	59,527	42,468	62,116	49,824	47,795	45,715	34,554	49,824	45,715
Heating Value	GJ/Bbl	5.84	5.84	5.84	5.84	5.84	5.84	5.84	5.88	5.88	5.79	5.84	5.88	5.79
Emissions		g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ	g/MJ
Total WTW Emissions		**100.2**	**102.5**	**98.2**	**103.5**	**106.9**	**102.1**	**112.9**	**112.7**	**115.6**	**111.2**	**103.4**	**104.7**	**102.7**
Vehicle CH4, N2O		**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Carbon in Fuel		**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**	**74.1**
Total WTT GHG Emissions		**25.3**	**27.6**	**23.3**	**28.6**	**32.0**	**27.2**	**38.0**	**37.8**	**40.7**	**36.3**	**28.5**	**29.8**	**27.8**
Oil Production		**6.1**	**9.0**	**5.0**	**11.8**	**16.8**	**10.1**	**18.9**	**14.2**	**12.6**	**13.8**	**9.6**	**7.3**	**7.1**
Production GHG		5.0	8.4	4.2	10.8	4.8	4.6	18.9	14.2	12.6	13.8	9.6	7.3	7.1
Venting and Flaring GHG		1.0	0.6	0.8	1.0	12.0	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Transport		**1.2**	**1.2**	**2.8**	**1.1**	**1.7**	**2.3**	**0.1**	**0.1**	**0.1**	**1.2**	**1.1**	**0.1**	**1.2**
Diluent Recycle		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**0.0**	**0.0**	**0.7**
Upgrading		0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.6	11.6	0.0	0.0	8.6	0.0
SCO		0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	10.8	0.0	0.0	7.3	0.0
Coke - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.6	0.0
Sulfur - Upgrading GHG to Major Products		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
Diluent Return - Upgrading GHG to Major Product		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.0
SCO Transport		0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.1	0.0	0.0	1.0	0.0
Refining - Upstream GHG to Major Product		**14.1**	**13.2**	**12.1**	**12.0**	**10.6**	**11.5**	**13.7**	**8.9**	**9.8**	**14.8**	**13.1**	**8.9**	**14.8**
GHG of Major Product		12.6	11.8	11.2	11.2	10.2	10.7	12.6	8.4	8.9	13.1	12.0	8.4	13.1
C3 - Upstream GHG to Major Product		0.3	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.4	0.3	0.2	0.4
C4 - Upstream GHG to Major Product		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coke - Upstream GHG to Major Product		0.7	0.6	0.3	0.2	0.1	0.2	0.5	0.0	0.4	0.7	0.4	0.0	0.7
Sulfur - Upstream GHG to Major Product		0.4	0.4	0.3	0.3	0.2	0.3	0.3	0.2	0.2	0.5	0.4	0.2	0.5
Delivery		**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Fuel Cycle		**3.1**	**3.3**	**2.7**	**3.1**	**2.4**	**2.6**	**4.6**	**4.6**	**5.0**	**4.9**	**4.1**	**3.6**	**3.9**
Natural Gas - Upstream GHG to Major Product		1.0	1.3	0.8	1.2	0.8	0.8	3.4	2.9	3.2	2.6	2.1	1.9	1.6
Electricity - Upstream GHG to Major Product		2.1	2.0	1.9	1.9	1.7	1.8	1.2	1.7	1.8	2.2	2.0	1.7	2.2
Other Feeds		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Diluent in Dilbit		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Isobutane for Alkylation - Upstream GHG to Major Product		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Impact of Replacing Coal with Refinery Pet Coke		**0.5**	**0.4**	**0.2**	**0.2**	**0.0**	**0.1**	**0.3**	**0.0**	**0.2**	**0.5**	**0.3**	**0.0**	**0.5**

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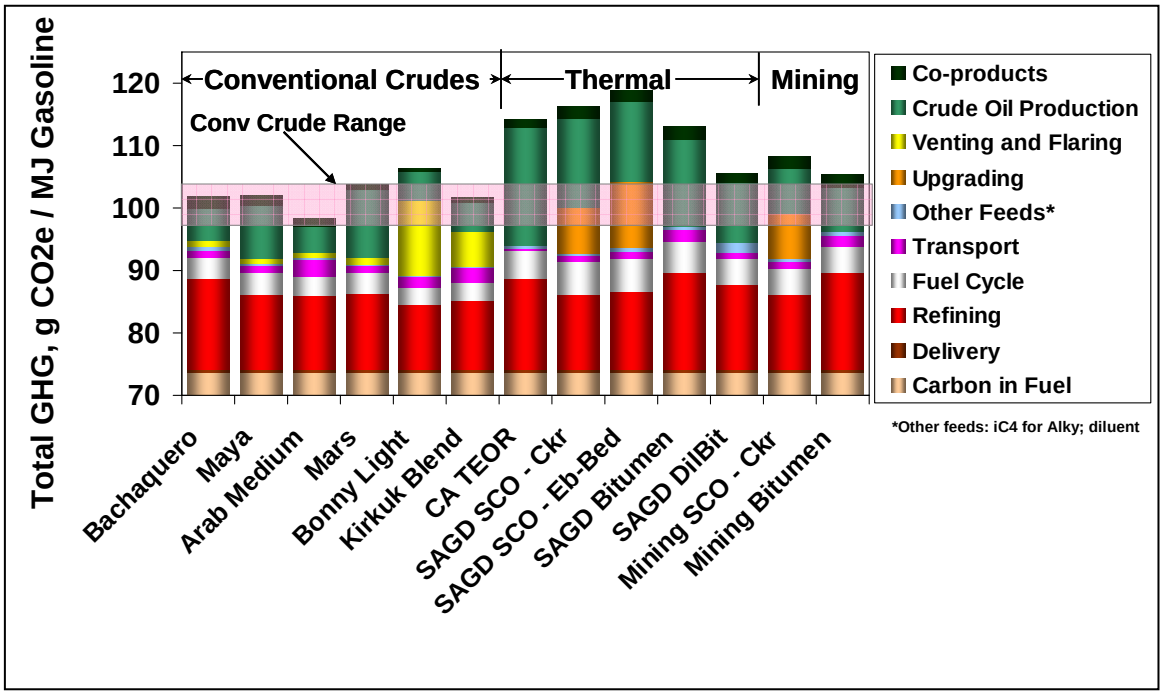
Figure 8-2.
Life Cycle Assessment of WTW GHG Emissions for Crude and Bitumen to RBOB



Note: Life cycle emissions, represented herein as WTW, include WTT emissions plus fuel carbon as CO_2, plus vehicle methane and N_2O. For identical vehicles, the gCO_2e/MJ representation above is the same as a traditional WTW representation in $gCO_2e/mile$.

Legend:

- Conventional crudes—Bachaquero; Maya; Arab Medium; Mars; Bonny Light; Kirkuk crude oils produced and transported to a high conversion refinery in PADD2 of the US where the crude is converted to mainly gasoline and diesel fuel used in PADD2.
- CA TEOR—California thermal enhanced oil recovery using cyclic steam injection in the central valley of California (Kern River).This heavy oil is refined in a high conversion refinery in California. Diesel and gasoline are used in California.
- SAGD SCO—Ckr – Bitumen produced in Alberta with a 3 SOR, upgraded in delayed coking based upgrader to produce bottomless SCO that is sent to a high conversion refinery in PADD 2 to produce primarily gasoline and diesel fuel.
- SAGD SCO—Eb-Bed – Similar to the prior case except that the SCO is produced in an upgrader based on an Ebulating Bed resid hydrocracking unit. The SCO contains unconverted oil.
- SAGD Bitumen—Bitumen produced in Alberta using a 3 SOR is transported to a US PADD 2 refinery as dilbit (naphtha diluent and bitumen); naphtha diluent is returned to Alberta.
- SAGD—Dilbit – Similar to the previous case except that the diluent is not returned to Alberta and is instead converted to gasoline.

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- Mining SCO—Ckr – Bitumen produced by surface mining is upgraded to SCO in a delayed coking based upgrader, shipped to a PADD2 refinery and converted to primarily gasoline and diesel fuel.
- Mining Bitumen—Bitumen produced in Alberta by surface mining. The bitumen is shipped to a PADD 2 refinery as Dilbit. The diluent is returned. This example is not extensively practiced because of the high sediment, chloride and water content of mined bitumen. However, with technology improvement, this practice may become more prevalent in the future.

Life cycle well-to-wheels results from the Study, summarized in Figure 8-2, show that the GHG emissions from producing transportation fuels from oil sands bitumen are smaller than suggested by previous studies. Results for RBOB are similar to those for CBOB (conventional blendstock for gasoline blending), a higher vapor pressure blend than RBOB, and ULSD (ultra-low sulfur diesel).

The band in Figure 8-2 represents the 6% GHG emissions gap between two conventional crudes, Arab-Medium and Mars. The GHG gap between Mars and Bonny Light is around 8%.

In this study, the GHG emissions from producing gasoline and ULSD from the same crude are similar. Heavier crudes require more processing in the refinery and result in greater GHG emissions from the refinery than when processing lighter crudes. Emissions from the vehicles contribute around 74 g GHG/MJ of gasoline and 75 g GHG/MJ of ULSD in a WTW assessment.

However, GHG emissions from crude production and refining vary widely, which has a big impact on overall emissions. The major factors affecting GHG emissions from oil production are the amount of flaring and venting, reservoir depth, and the water-to-oil ratio. In the case of thermally produced oils and bitumen, the steam-to-oil ratio has a significant impact on energy and GHG emissions. Crude API is well correlated with the energy required to refine it. The distance that the oil has to travel to the refinery has a minor impact on GHG emissions.

Our results show that the WTW GHG difference between Arab-Medium and bitumen is less than 18% for bitumen from SAGD and approximately 10% for bitumen from mining. Both of these bitumen cases assume that the bitumen is first upgraded to SCO in a delayed coking-based upgrader before refining the SCO in a PADD2 refinery. If instead diluted bitumen is shipped to the PADD2 refinery, the difference between Arab-Medium and bitumen drops to 15% for bitumen produced by SAGD. If the diluent is then converted to gasoline in the refinery, total WTW GHG emissions are comparable to the conventional crudes. The gap between Bonny-Light and diluted bitumen sent to a PADD2 refinery is only 6% (assuming diluent return to Alberta).

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A major observation from this analysis is that GHG emissions from converting crude and bitumen to transportation fuels are highly dependent on how these crudes and bitumens are produced. Further, the difference in WTW GHG emissions for producing transportation fuels from conventional crudes and bitumen is much smaller than shown in earlier studies. In some cases there is very little difference between the GHG emission results from conventional crude and bitumen-derived transportation fuels.

Impact of Cogeneration

Cogeneration is a significant source of steam and electric power for thermal oil production. Fired steam generators and cogeneration turbines represent most of the GHG emissions for thermal oil options including SAGD, surface mined, and California thermal enhanced oil recovery. The use of cogeneration to produce both power and steam is more efficient than producing each utility separately. The base WTW results presented above in Figure 8-2 for thermally produced California crude and Canadian bitumen reflect the efficiency and direct utility emissions from oil production based on a level of steam and power cogeneration to the extent that the production facility power needs are fully met but without any net export of power.

However, many of the production sites in both Canada and California generate a larger amount of steam and power using onsite natural gas cogeneration and export excess electric power to the local grid as a co-product. Thus, from a life cycle perspective, co-product emissions credits may apply if displacing power generated using higher carbon content fuel, such as coal-fired power. The energy inputs and treatment of co-produced electric power have a significant impact on the life cycle GHG emissions associated with California heavy crude and Canadian oil sands production.

While the scope of this Study did not include a comprehensive evaluation of site-specific cogeneration opportunities and impacts, a preliminary analysis was carried out for Canadian bitumen to illustrate the potential for such co-product emission credits from export of cogenerated power. This preliminary analysis assumes substitution of the natural gas-fired cogenerated export power replacing local grid electricity. This substitution method is consistent with the GREET model's treatment of import and export power and associated indirect emissions. For example, in determining the co-product emissions impact of cogenerated power associated with cellulosic ethanol production in the US, the average US grid mix is assumed to be offset.

For illustrative purposes, the following basis was used for the preliminary analysis of cogeneration power export from Canadian bitumen production sites:

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Cases	Natural Gas Fired Cogen Power Export, kwh/bbl	Local Grid Power Displaced
(A) SAGD Bitumen—no cogen	0	na
(B) SAGD Bitumen—full cogen	99 *	Natural gas fired cogen
(C) SAGD Bitumen—full cogen	99 *	80% coal fired
(D) SAGD Bitumen—partial cogen	40	80% coal fired
(E) Mined Bitumen—no cogen	0	na
(F) Mined Bitumen—full cogen	48 *	80% coal fired

The export power shown above for cases with asterisks (*) are based on generating 100% of the steam required for bitumen production via cogeneration. While not all bitumen production sites currently in operation export this much power, most new facilities are being designed this way. It should also be noted that a rigorous evaluation of the local power grid was not carried out to determine the actual mix that would be displaced by cogenerated export or the impact on grid efficiency. Thus the above cases bracket a high and low range.

Figure 8-3 shows the impact of generating and exporting differing amounts of electricity in bitumen production consistent with the cases above. The left most bar in Figure 8-3 shows the GHG emissions from producing bitumen at a 3 SOR with no cogeneration (Case A). In this example, electricity produced on site from natural gas is sufficient to run SAGD production. The next two bars in Figure 8-3 shows the impact of cogeneration and exporting 99 kwh/bbl of bitumen (Cases B & C). GHG emissions above the x axis are for SAGD including cogeneration. GHG emissions below the line are the credit for displacing grid based electricity as a result of exporting power. The net GHG emissions are shown by the line on Figure 8-3. Note that the direct emissions GHG footprint for cogeneration and export of surplus power is larger than simply generating enough electric power and steam for bitumen and heavy oil production with no export of surplus power.

In the first example that exports 99 kwh/bbl of power (Case B), the credit is taken against grid power based on natural gas. The second example takes credit against the Alberta grid based on 80% coal fired power (Case C). In the case where cogenerated electricity displaces natural gas based grid power, the credit is not sufficient to offset the additional GHG from cogeneration. For the 80% coal fired grid case, the credit from cogeneration is significant and essentially offsets the GHG emissions from SAGD including the additional emissions from cogeneration.

The next example shows the impact of cogeneration with export of only 40 kwh/bbl of bitumen produced (Case D), which may be more typical of older facilities that export power. The rightmost examples on Figure 8-3 show the impact of cogeneration in bitumen mining (Cases E & F).

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Figure 8-3.
Impact of Cogeneration on GHG Emissions from Bitumen Production

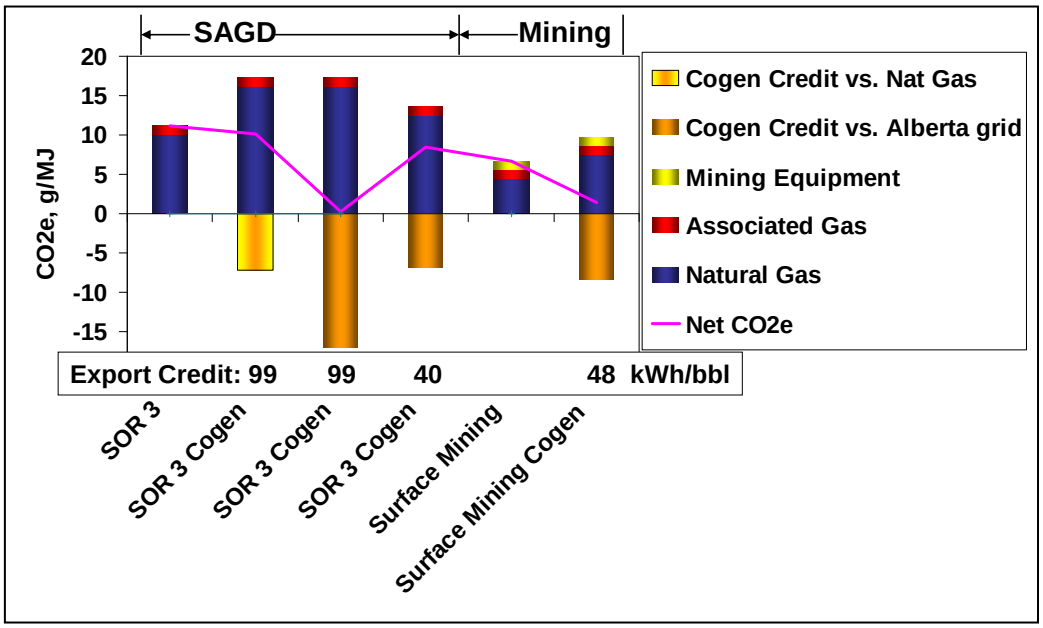

Figure 8-4 shows the potential impact on WTW life cycle GHG emissions from Canadian oil sands for Cases C (SAGD) and F (Mining). The arrows on the diagram show the change in GHG emissions from applying this full cogen credit. For the set of assumptions used in this preliminary analysis, the export provides enough co-product emissions credit to essentially offset the GHG emissions from bitumen production. When these credits are applied, the result is that the life cycle GHG emissions for bitumen-based fuels are well within the range of fuels from conventional crudes

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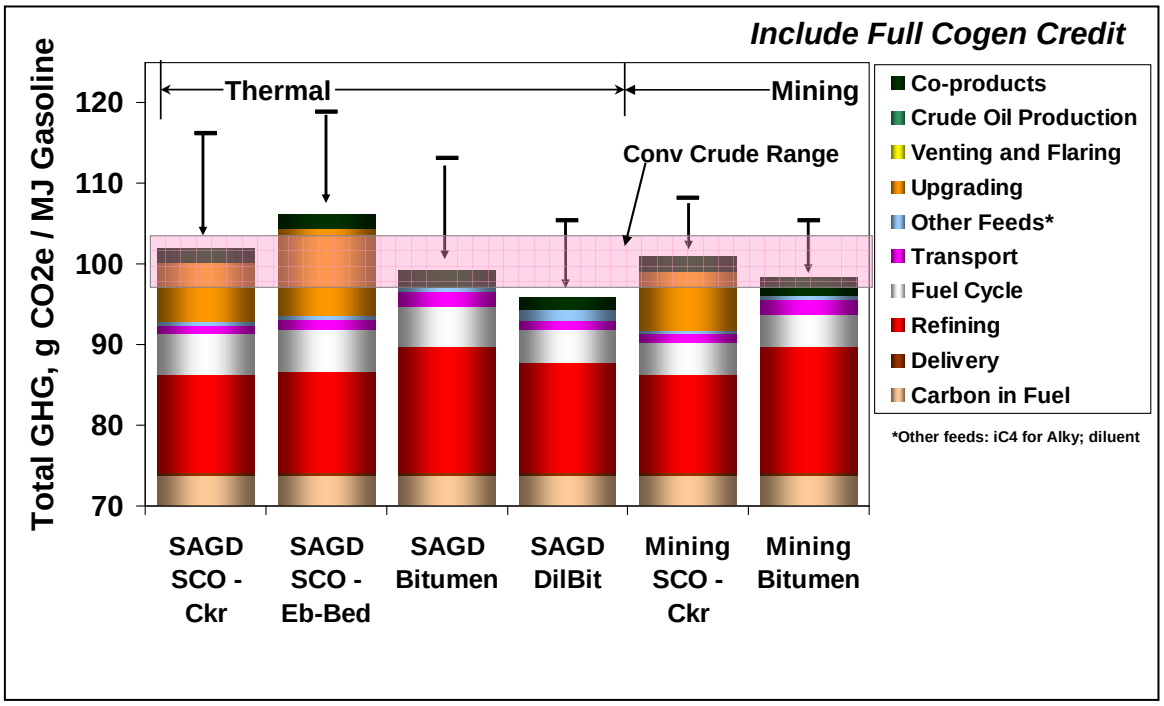
Figure 8-4.
Life Cycle Assessment of WTW GHG Emissions for Bitumen to RBOB—Full Credit for Cogen



It should be noted that the above credit may not be fully achievable based on the actual amount of export power from specific production facilities, the actual Alberta grid mix (coal, gas, hydroelectric, other), the balance and source of grid base and peak power production, and the impact of the exported power on the existing power generation facilities supplying the grid. It should also be noted that the analysis of cogeneration and power export is relatively complex. For example, while the availability of this electricity supply may avoid the need to construct some type of new power plant or the need to procure the same amount of electricity from some other source, it may also cause excess capacity on the grid and inefficient operation of other electricity generation resources.

Therefore, a further more detailed evaluation is required to more accurately understand the potential credit for cogeneration and power. Regardless, the impact of cogeneration is significant, and even if only one half of the above credit indicated in Figure 8-4 is achievable, the life cycle WTW GHG emissions for fuels from bitumen produced by mining and SAGD are still within the range of many of the conventional crudes examined in this Study, as shown in Figure 8-5.

Lastly, it should be noted that the above analysis was not carried out for California thermally produced crudes as part of the Study. Potential for export power co-product emissions credits

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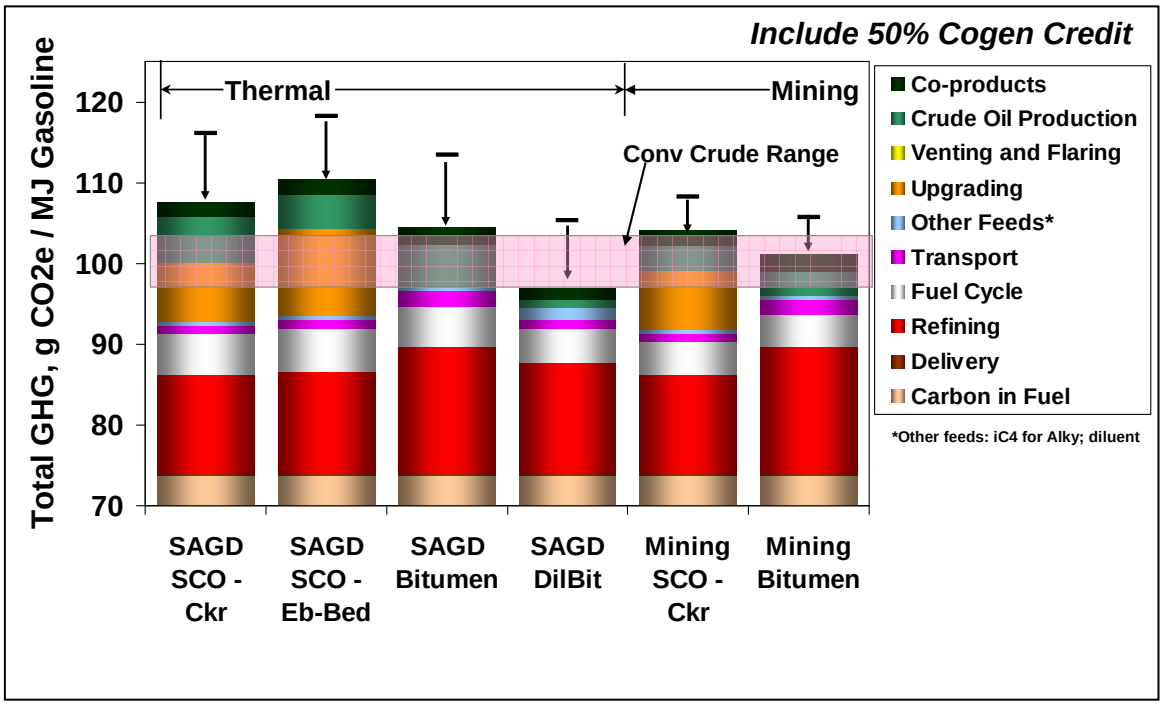
also exists for these California crudes. It is recommended that this potential be considered as part of a future more comprehensive evaluation regarding the impact of cogenerated power export.

Figure 8-5.
Life Cycle Assessment of WTW GHG Emissions for Bitumen to RBOB—50%Credit for Cogeneration



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References

EIA, *Documentation for Emissions of Greenhouse Gases in the United States 2006*, EIA, October 2008

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Section 9.

Conclusions and Recommendations

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Conclusions

Jacobs Consultancy concludes the following:

- Accurate ranking of specific crudes and bitumens requires an in-depth Life Cycle Analysis that takes into account the actual differences in energy and GHG impact from their production, upgrading and refining to products.
- Crude production modeling provides transparent and consistent handling of crudes and fills gaps in inaccurate or incomplete public data. Much of the information that is publicly available about crude production is either too aggregated or missing important pieces of information, thereby making WTW analysis of crudes and bitumens unreliable. Use of a fundamental crude production model supplemented with actual data provides a better understanding of the major factors affecting GHG emissions from crude production.
- Rigorous upgrading and refining models define emissions for specific crudes and allow differentiation of GHG burden between products. Heavier crudes require more energy to refine and therefore have greater GHG impact. Products that require significant refining tend to have greater GHG impact than products with less refining. Accounting for the impact of crude and processing will result in better understanding of WTW GHG impact for different fuels produced from different crudes and bitumens.
- GHG emission gaps between bitumen and conventional crudes are smaller than reported in some prior studies. The wide range of GHG impact from conventional crudes as a result of energy intensive production methods is one of the significant outcomes of this study and will enable more informed discussion of LCFS policy.
- Unique opportunities exist to improve the GHG footprint for Canadian oil sands relative to other crudes. These include cogeneration as well as large scale efficiency improvement and carbon capture and storage opportunities.
- New facilities built in Canada for bitumen production, upgrading, and refining can more easily and cost effectively manage GHG emissions than older facilities in the US or offshore oil production sites with less rigorous environmental standards. In addition, many new facilities in Canada are near sites that can be used for CO_2 sequestration.

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Recommendations

Recommendations for areas of further work identified as part of this Study include:

- Widen the scope of crudes analyzed to include crudes such as Alaskan North Slope, which is refined in California, additional US domestic crudes, and Canadian crudes
- Evaluate other bitumen upgrading technologies and configurations, including those that directly utilize coke or a portion of the bitumen for upgrading energy supply.
- Identify and determine the magnitude of potential energy and efficiency improvements in the full WTW lifecycle of producing, upgrading, and refining bitumen.
- Develop a more thorough analysis of cogeneration credit opportunities for thermally produced heavy crude and bitumen in California and Canada.
- Evaluate the impact of large scale carbon capture and sequestration on bitumen production, upgrading and refining in Canada
- Determine the lifecycle impact of using alternative fuels in bitumen production, upgrading and refining
- Consider how the potential mitigation opportunities might also apply to other crudes.

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