Executive Summary

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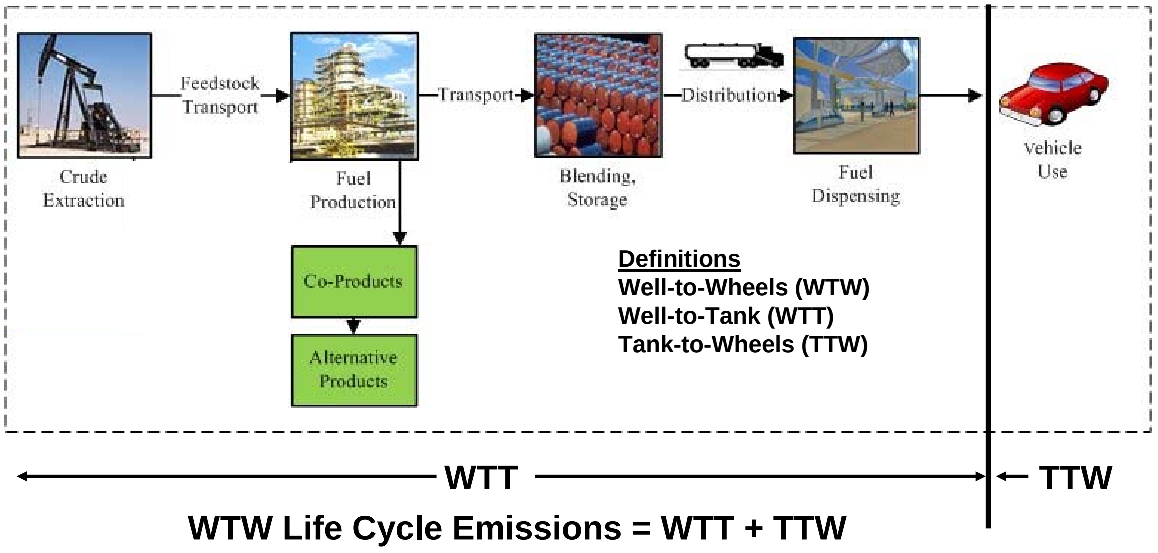
The State of California has introduced a Low Carbon Fuel Standard (LCFS) with the stated objective of reducing the carbon intensity of its transportation fuels by 10% by 2020. The introduction of a national LCFS in the United States may have implications regarding how the Canadian oil sector responds 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

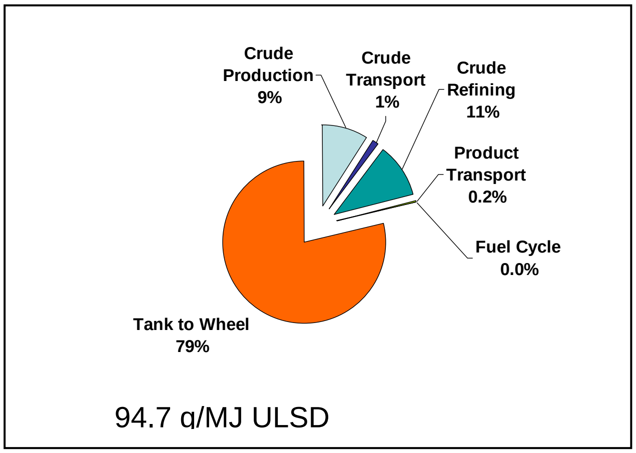
The starting point for determining the carbon intensity of a fuel is a well-to-wheels (WTW) life cycle assessment. This methodology evaluates the energy used and greenhouse gas (GHG) impact in each step from producing a crude oil or bitumen, converting it to transportation fuels, and consuming the fuel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

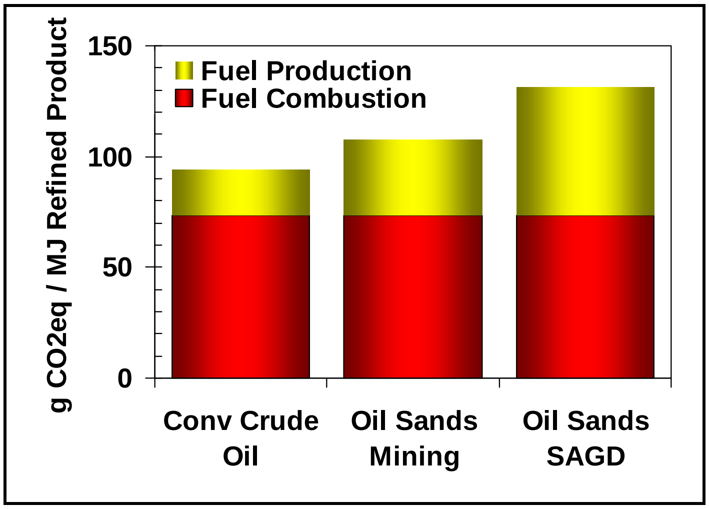
Figure E-2.
CARB Estimate of GHG Emissions from ULSD Production



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

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.

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.

Crudes and Bitumens in Study

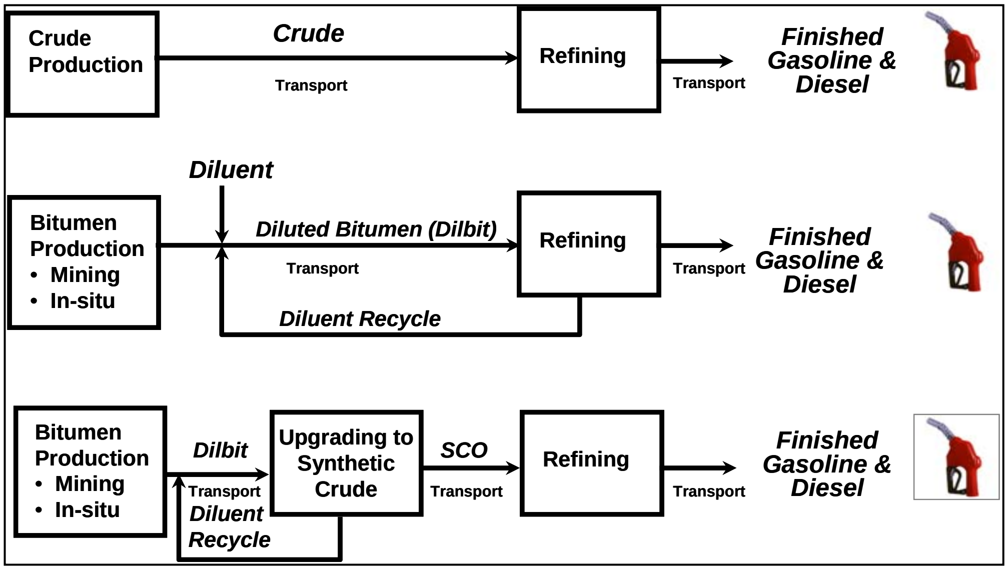
The following crudes and oil sands bitumens were examined:

- 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:

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.

- 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.

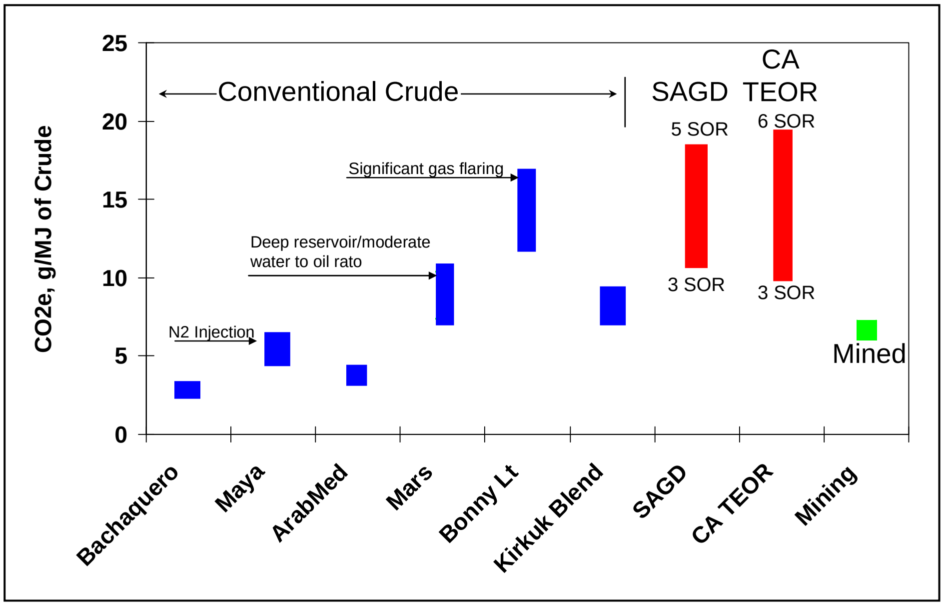
A comparison of reservoir and production characteristics for crudes in this Study is shown in Table E-1.

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.

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.

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

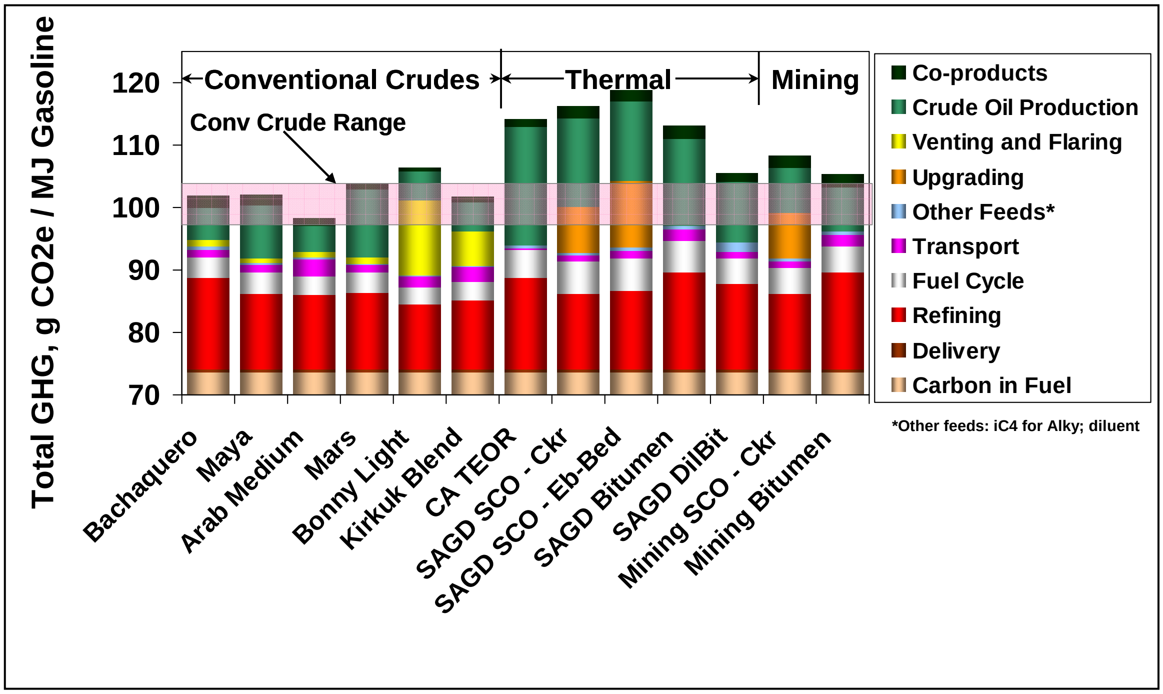
Our calculation of emissions from transportation of crudes, bitumen, and SCO to the upgrader and refinery as well as distribution of products from the refinery uses factors from the GREET model. Transport distances reflect the location of the oil reservoir considered in this Study. Fuel cycle emissions 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).

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.

- 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.

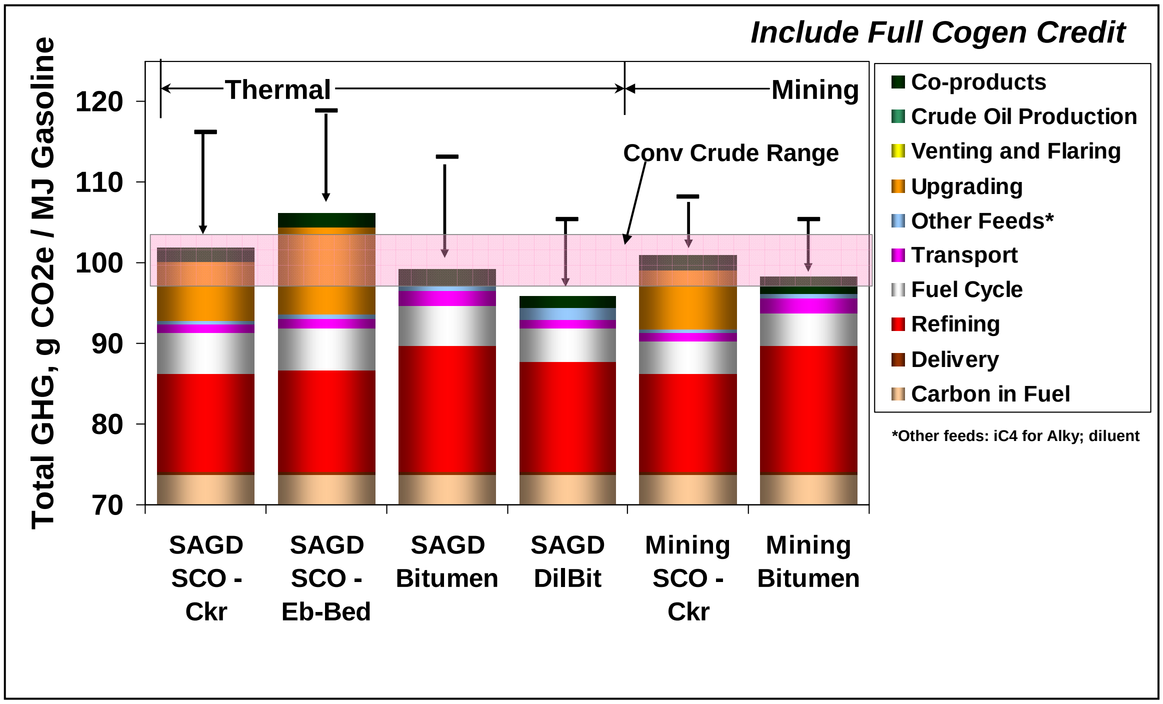
For illustrative purposes, the following basis was used for the preliminary analysis of cogeneration power export from Canadian bitumen production sites:

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

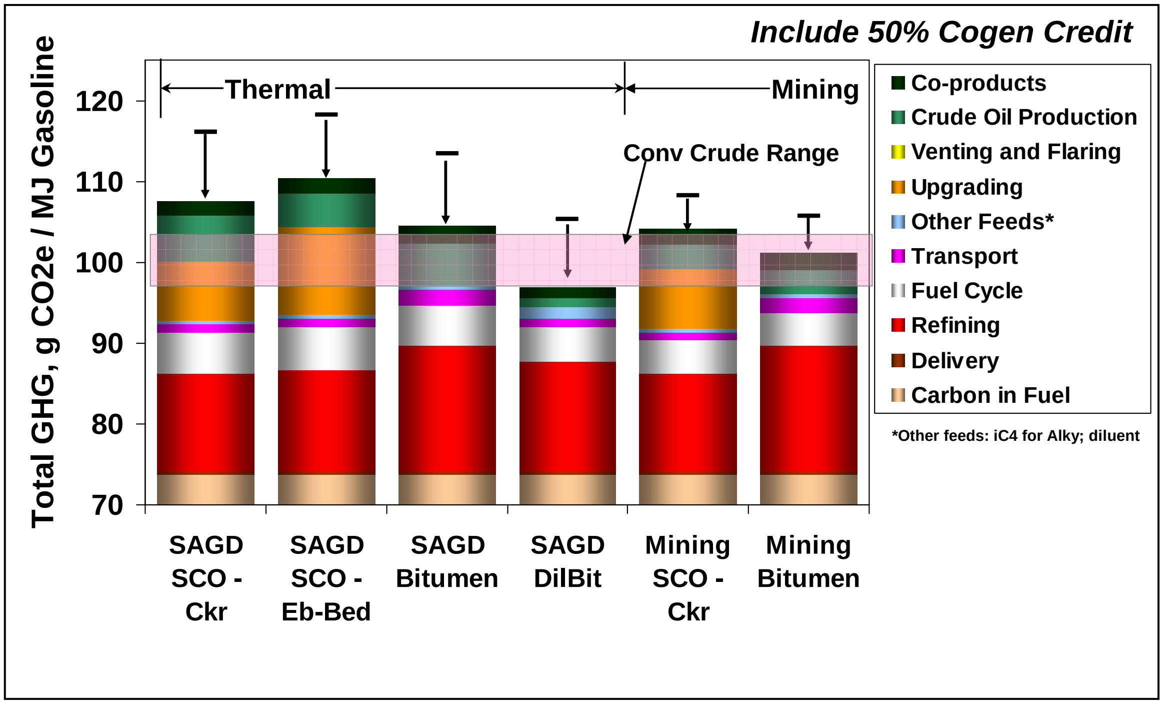


It should be noted that the above credit may not be fully achievable based on the actual amount of export power from specific production facilities, the actual Alberta grid mix (coal, gas, hydroelectric, other), the balance and source of grid base and peak power production, and the impact of the exported 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.

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.

- 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.

References

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