Jacobs Consultancy

Stakeholder Input

Feedback from:

Jacob's Life Cycle Analysis Workshop March 13, 2009

Calgary, Alberta

#	Name Organization	**Verbatim Comments [***Via email – unless otherwise noted***]**
1	**Damien Hocking** **MEG Energy**	I just wanted to say well done for Friday's presentation. You can really see the difference with an engineering company that works in oil & gas and refining on a daily basis. There are quite a few happier people at MEG today.
2	**Ed Koshka** **Ivanhoe Energy Inc.**	Thank you for the information session last Friday with Jacobs. I found it very informative. As mentioned, we have completed our LCA with Len Flint and would like to have an opportunity to share those results with you. Len has some unique perspectives on the issues and could be of use in your work with Jacobs and TIAX.
3	**Derril J. Stephenson** **Vikor Energy Inc.**	Thank you for inviting me to the presentation on Friday. AERI are to be complimented on undertaking the study, the "dirty oil" stigma will be difficult to fight but having facts will help.
4	**Brent Stuart** **Suncor Energy**	[*Verbal*]: Great show! This is the message that we have been trying to convey for the past few years.
5	**Tom Corscadden** **MEG Energy**	[*Voice Mail*] Thanks! The workshop provided a very good perspective on the cogeneration issue.
6	**David Stachniak** **Laricina Energy**	Thanks for the invitation to the Life Cycle Assessment Comparison of North American and Imported Crudes session on March 13. The session provided great insight into the development of what I consider to be a key tool for establishing GHG emission policy Canada and the United States.

Key Notes, Comments, Questions, etc. - 13MAR09 AERI LCA Meeting

1. Surindar Singh, AERI - Meeting purpose is to present methodology & data, gather feedback before study is finalized. Intent is to keep study as transparent as possible with key stake holder input.

2. Dave Stachniak, Laricina Energy – Jacobs Consultancy is using different crudes vs. TIAX – was this purposeful? *Answer: No. Crudes used by Jacobs Consultancy were selected independently. AERI plans to rationalize two separate studies when they are complete.*

3. Catherine Laureshen, Total – Did we consider SCO as diluent? *Answer: No. Just Dil-Bit.*

4. Mike Layer, NRCAN – Did we consider diluent return to Alberta? *Answer: No. We have not considered this yet. Our intent was not completely address every possible option. We have tried to bracket options with dilbit and SCO to US case.*

5. Mike Layer, NRCAN – have we accounted for global trend in API dropping over time. *Answer: No this was not included in the scope of our study. We will comment in our report on this issue.*

6. Catherine Laureshan, Total – *Does model include thermal production? Answer: No these are handled separately outside of the model.*

7. Ed Koshka, Ivanhoe – Did we include nitrogen for Cantarel field – using 2 BCF per day, 1000 MW per day to run ASUs. *Answer: No. Will follow-up with Ed after meeting.*

8. Dave Stachniak, Laricina Energy – Did we include any Canadian light? *Answer: No we did not in this study.*

9. Ed Brost, Shell – Slide 24 – are water numbers produced? *Answer: Yes. We did not look at water injection. Lifting energy overwhelms energy*

10. Ed Koshka – Can we see input data to crude production model? *Answer: Yes*

11. Mike Layer, NRCAN – *better info on venting emissions will be available as we move into future*

12. Ted Little, NCUT - It appears that you use SAGD as the representative for in situ bitumen production. Did you look at GHG emissions from other in situ bitumen production (eg. THAI), or cogen plant. Answer: *No re. THAI and yes re. cogen.*

13. Chris Holly Alberta Energy, DOE – CA applying 15 g/MJ criteria. Does this mean some of crudes meet this? *Answer: Yes*.

14. Cameron Brown, Alberta Energy – does it seem inconsistent that CA is developing standards but CA TEOR oil has high emissions? *Answer: Yes*

15. Tom Corscadan, MEG – taking look at SORs CA vs. SAGD – 80% quality steam, put all wet steam down hole vs. 100% quality steam for SAGD. *Answer: Yes this was addressed in our calculations as a percentage.*

16. John Kenny, Alberta Environment - Are the intensity numbers normalized to reflect the varying products to make an apples to apples comparison? Or are we looking at different products? I don't think it is based on the forthcoming slides? *Answer: final LCA results are normalized to GHG emissions per GJ of gasoline.*

17. Nester, Nexen – Co-products – for example did we model coke burning in cement kilns, etc. *Answer: Yes.*

18. Tom Corscadan – Assuming coke goes into market, how do you burden someone like OPTI burning? *Answer: Use actual emissions for particular fuel source. So there is more burden than a gas fired facility. Will review this further as finalize study.*

19. Nester, Nexen – Since there are different types of crudes accounting for different qualities of crude? *Answer: Yes*

20. John Kurtz – Does model accurately and fully represent upgrading? *Answer: Yes from many jobs.*

21. Lester Wyborny II, Engineering Specialist US EPA - Currently, natural gas is used for upgrading the bitumen. However, looking towards the future as additional bitumen is being developed, perhaps other energy sources for bitumen upgrading will be used. Because Canadian natural gas supplies seem to be decreasing, perhaps two different sensitivities should be done for the energy input. One would be to shift to using bitumen for upgrading energy. The second, in a carbon controlled world, would be to use energy from nuclear power plants. I suggest assessing the bitumen upgrading process using these two other energy inputs. *Answer: this is not currently in study scope of this work - will consider this as we finalize study. Jacobs has also done another study on this which will be made public.*

22. Nester – What is GJ unit reference on our charts? *Answer: GJ of RBOB*

23. Lester Wyborny II, Engineering Specialist US EPA - It seems that addressing the flaring of natural gas produced at oil fields could be the low hanging fruit for reducing GHG emissions in a carbon controlled world. I suggest that you present your results assuming that the flaring is no longer occurring, either the flared gas is reinjected into the oil field, or it is captured and used. *Answer: noted and agree*

24. Tom Corscadan – Slide 33 – what SORs assumed. *Answer: SAGD = 3, CA = 5*

25. Catherine Laureshan – transportation – what is location? *Answer: assumed PADII type refineries for bitumen based streams.*

26. Chris Holly – Proposed LCFS 96 g/GJ – is our y-axis consistent with this functional unit of measuremen? *Answer: Yes*

27. Tiffany Groode, CERA - What would be the conversion you would use for slide 33 to go from gCO2/GJ or gasoline to gCO2/bbl of crude? What is the assumption of how many gallons of gasoline is produced from a barrel of crude? *Answer: varies by crude type and product mix specifically.*

28. Nester Zerpa, Nexen – why is dil-bit so low? *Answer: diluent is going into refinery and being converted and blended into gasoline pool.* Ed Koshka follow-up comment – these bars are mis-leading.

29. John Cortis? CARB – California LCFS is based on basket of crudes vs individual not just CA TEOR. *Answer: We agree.*

30. Ed Brost, Shell – Calif incremental natural gas is LNG. Is this considered? *Answer: not part of our study. Will consider as we conclude study.*

31. Song P. Sit, EnCana Corporation

    a. Please check unit of flare gas because Bonny Light's flared gas exceeds produced gas

    b. Several SAGD projects have SOR less than 3

    c. What is the source of GHG intensity of mined bitumen (Slide 25)? We are asking for the origin of the data

    d. CA TEOR average SOR is actually 5.05 (Slide 25).

    e. (Slide 27) It seems that the Dilbit has too much naphtha at 40% than AB actual blend of 30%.

    f. William, please explain how you handle refinery coke? Do you allocate the difference between coke and coal to gasoline? or just the coke burning emissions to gasoline?

    g. Slide 30 – does SCO-Ckr emission includes emission of upgrading

32. Lester Wyborny, US EPA - Have you assessed why your lifecycle emissions analysis shows lower life-cycle impacts by bitumen compared to previous studies? This would be a valuable exercise for sorting out whether the previous studies did a viable analysis, and their results are driven by differing but reasonable assumptions, or if their analyses were flawed or biased in some way.

33. Ted Little, NCUT - Considering the attached gas (Statistics Canada 2008), illustrating decreasing NG production. There should be some qualification or weighting factor that addresses using this high quality clean fuel in transportation fuel production,

especially if bitumens and heavy oils are able to use gasified asphaltenes as an energy source to offset the use of highly valued NG from outside sources. This would be particularly important if the lighter crudes must rely on the highly valued NG resource for hydrogenation and other refinery processes. In other words, the use of produced asphaltenes out of the total yield to generate hydrogen and other power must be considered in a positive way in your model (in my opinion).

34. Unknown name – What do we assume for grid power? *Answer – varies by region. Nat gas cogeneration power.*

35. Gerald Bruce, MEG Energy - System boundary observation (slide 46) - Conventional crude to gasoline?What about all transportation fuels?. Including diesel? Suggest there is a max gasoline and max diesel scenario. *Answer: Yes we are looking at emissions across all products including diesel.*

36. Chris Holly, AE DOE – Slide 51 is confusing and might be misunderstood.

37. Keesom – life cycle emissions should be gCO2e per MJ vs. GJ

38. Unknown name – What flaring combustion efficiency did we use? *Answer: 99%*

39. Chris Holly – slide 81 - be careful about reporting SORs from pilot projects, Nexen comment: 8 SOR is from pilot project – actual commercial target is 3.3 SOR. Cameron Todd, Connacher comment: not many SAGD being designed for more than 3-4 SOR due to economics (2.5-3 for Connacher). Distinguish between CSS and SAGD – makes big differnec. EnCana comment: Using 3 SOR may be too conservative, they are running 2.3. *Answer: We agree with comments and will review this issue and add more fidelity and clarity.*

40. Song Sit, EnCana - Looking ahead to Slide 84, it shows mining emission of about 7 kg per GJ (bitumen?). What is the assumption of overburden to ore strip ratio? What is the diesel consumption per tonne of ore? Haul distance of ore to crusher? Haul distance of overburden to overburden dumps? Pumping distance of tailings to tailing pond? What is the slurry temperature and bitumen extraction temperature? What is the naphtha loss per barrel of bitumen and what is the fugitive from the naphtha in the tailings pond? What is the fugitive from the mine face? *Answer:*

41. Ted Little, NCUT, and Cameron Todd, Connacher – should get credit from cogen power export to grid to back out coal based power generation. *Answer: we agree this is a very interesting policy issue, but we have not taken cogen credit in the preliminary LCA results bars we presented today. This is an important policy discussion.*

42. Chris Holly, AE DOE – Comment: CARB was given information on Alberta grid and cogeneration. Every commercial SAGD project has cogen associated with it. See Athabasca Resources Committee document on web.

43. Lester Wyborny, US EPA - The credit that you may be able to claim for cogen should be against the marginal electricity produced, which is probably natural gas not coal. *Answer: Agree*

44. John Cortis, CARB – does use of natural gas in SAGD result in other emissions where higher carbon fuels are burned due to lack of gas availability. *Answer: the scope of our study has not addressed this.*

45. Christa Seaman, Canadian Natural Resources – comment: should include impact of co-gen in our results to be sure we are doing a scientific study vs. policy study. Don't call it a credit – say actual emissions including cogeneration. *Answer: will consider this further – and we will use different nomenclature.*

46. Bill Greenizan, Ontario Ministry of Energy & Infrastructure - One comment on slide 81 re: the Cogen credit.

    a. I would point out that the Alberta Grid is not island – for example Alberta exports electricity in off-peak hours to B.C (a hydro based). The Cogen from oilsands is the last generator to turn off (it is commonly referred to as "must run Cogen"). In other words, at night coal generation would be backed off to minimum generation levels before the oilsands cogens.

    b. The Alberta Grid credit calculation would have to account for imports/exports.

    c. It gets complicated in a hurry.

47. Ted Little, NCUT – I am writing to just have my earlier verbal comment recorded for Jacob's benefit. No need to reiterate to group. In regards to cogen, don't only consider the electric grid contribution, but also the faction of the barrel that is used in hydrogen production via gasification of asphaltenes. In other words, no co-gen is bbl + NG use in upgraders and refiners; cogen is bbl – SG used from the bbl it was produced from… this may translate into a GHG reduction of BBL+ vs BBL- from a GHG production ration purpose. Just a thought.

48. Unknown – A lot of heavy crude blended into WCS. Comments? *Answer: Our study scope does not include addressing every crude. We do not plan to include WCS in this study.*

49. Lester Wyborny, US EPA - What fraction of the SAGD bitumen is being produced/upgraded using cogeneration?

50. Randy Armstrong, Shell Oil - Shouldn't we adjust California TEOR for co-generation in the same way we do SAGD?

51. Ted Little, NCUT - For the record (no need to present to group):

a. If you are considering in-box produced fuels as non-contributors in a refinery (as per your , you should do the same for cogen with respect to both electrical generation, hydrogen produced and steam produced (for both heat used in SAGD and hydrogen production)

b. Just a comment for your consideration… treat refineries and cogen upgraders (e.g., Nexen, Long Lake) in similar ways with respect to the "in the box" sources and power supplies.

52. Nester Zerpa, Nexen – Consider treatment of burning asphaltenes the same way we are treating coke and displacement of coal. *Answer:* discuss offline.

53. Ted Little, NCUT - Did you consider "Transportation" GHG contributions surrounding the transportation of coke to appropriate stockpiles? Would this be worth considering?

54. Unknown – if we are accounting for fuel to run mining operation, then we should count for fuel used to run helicopters to offshore rigs. *Answer:*

Submitted Questions from Interim Review

Tom Corscadden MEG Energy 3/16/09 email
New generation upgraders will be required to utilize the coke – it is an energy source and Alberta Energy will apply pressure to ensure that it is not wasted. Alberta Environment, on the other hand will require emissions mitigation for criteria pollutants as well as for carbon. This will likely mean some form of gasification and carbon capture and storage. This is likely to be the leading edge for CCS. IF we allocate these emissions to the transportation fuel products and do not apply the emissions from coke to the refiners transportation fuel products, we are being inconsistent and sending the wrong message (and we know what has been done with this kind of message in the past). My thinking is that we need to apply the coke emissions to the products in any case – this will lead to better information regarding the carbon footprint of the entire barrel.

Tom Corscadden MEG Energy 3/16/09 email
The Diesel cycle is a more efficient cycle and vehicles will travel more km for every GJ of diesel consumed. If “we” are serious about reducing the impact of transportation fuels, this is where we should spend some significant focus as it represents 80+% of the total footprint. A shift to diesel should reduce the transportation footprint – I believe, but I would like to test that hypothesis. It would be interesting to know what fuel product mixes are possible from a refinery geared up to produce diesel. I think that it would be pretty clear that the heavier feedstocks will produce a larger volume of these products. It would be interesting to then test the carbon footprint per km driven with this mix against the normal gasoline mix.

David Stachniak, Laricina Energy:
Advise what the SOR you used for the California TEOR emissions calculation and on what steam quality basis?

David Stachniak, Laricina Energy
Crude Slate
I noticed that the crude slate is different between the Jacobs study and TIAX study. Assuming that the commissioning of the same study to two companies was intended to provide some form of quality control, I would suggest that the crude slates be the same and not be left up to the two contractors to decide. In doing so, I recommend retaining the SAGD dilbit pathway that the Jacobs study is evaluating. I believe that this pathway should be included as it represents the most promising pathway for reducing the GHG footprint of oil sands production through the use of solvent aided processes, which reduce steam injection requirements. Modeling this pathway should lay the foundation for future evaluations. My comments also reflect my concern that SAGD is being pushed through SCO for some deemed equivalence even though the TJ McCann analysis would suggest that refining based upgrading has fewer emissions.

In addition, the “fair comparison of crudes that are imported into the United States” outcome that AERI anticipates may not be delivered with the crude slate under consideration. First, there is an inconsistency in the treatment of crude oil from Canada compared to other crudes. Canadian crude exports are being disaggregated into dilbit and SCO streams while other crude blends are not. For a fair treatment of crude oils, the analysis needs to be based on either the import blend at the US border or all streams need to be disaggregated and analyzed at the field level. The current analysis on an import blend basis would require a WCS pathway be incorporated into the model. Second, comparable heavy crudes are not part of the crude oil slate. Canada’s oil sands and Venezuela’s Orinoco belt have the world’s largest known heavy oil reserves and a direct comparison would be better than a comparison to Venezuelan Bachaquero.

One notable omission from the crude slate is Canadian light oil. While I don’t necessarily support the comparison of oil sands production to light oil, it has become a benchmark for comparison and its omission will draw criticism of the study.

Crude characterization

My greatest concern is that the characterization of all crudes is not as rigorous as for Canadian oil sands production. While TIAX dismissed this concern, it is also expressed by Cambridge Energy Research Associates in their upcoming report entitled “Growth in the Canadian Oil Sands? Finding the New Balance”, where they write “…international data must be accurate and verifiable. Without such a guarantee, Canadian oil sands could be unduly penalized for being more transparent.” I reiterate my recommendation that experts for each country or crude oil be engaged to help characterize each crude oil.

Transparency and Credibility

In both the TIAX and Jacobs presentations the issue of transparency was raised as a concern. To appear unbiased, the project was to source only public data for its analysis. In the case of oil sands mining, this has lead to the utilization of hypothetical information from projects that are not currently operating. The response to these concerns was that private data from Syncrude and Suncor would make the analysis less transparent and therefore less credible. I would argue exactly the opposite. Transparency in this case exposes the shortcomings in the data and is detrimental to credibility. Jacobs was not explicit in terms of what it was using for mining data. Please confirm the data sources for oil sands mining operations.

SOR Range for SAGD

I have attached a paper from Peters & Co. which outlines the current performance for SAGD projects to supplement the dated information that Jacobs has. The current SOR range for mature projects is between 2 and 4 rather than the 3 to 5 that Jacobs is considering. One other note regarding SOR, while Jacobs did not address in situ production using CSS, I want to be sure that TIAX is aware that CSS operations use 80% quality steam rather than dry steam like in SAGD operations.

GREET Model

Will the modified GREET model be made available for review? Will the modifications be incorporated by the GREET developers so that they are publically available?

Ted Little, NCUT

Transportation: GHG contributions surrounding the transportation of coke to appropriate stockpiles? Would this be worth considering?

James Lee, Nova Chemicals

Industry associations and the government sections looking at LCA will also be interested in this work in the context of LCFS and renewable fuels. I think showing the LCA results using GREET and GHGenius would be helpful to them.

Treatment of CoGen

The Alberta and Canadian Federal governments have an agreed methodology on how to treat CoGen for GHG contributions.

FCC Coke

How are GHG's generated from burning coke off the catalyst treated?

· Some jurisdictions do not count GHG from FCC's to the refinery GHG burden

SMR's

How are GHG's generated from steam methane reformers treated?

· Some jurisdictions do not count GHG associated with H2 from SMR's to the refinery GHG burden if the H2 is used for gasoline and diesel desulphurization.

Marine Transportation

Different ships/barges meet their fueling needs depending how close they are to land and to different jurisdictions.

· Are you counting the GHG's generate from shipping from departure to arrival point or from a regulated perspective (which can be less)

Accounting of CoProducts

Given the Alberta's new Energy Strategy, I think how GHG is recognized in the upgrading to higher value added products such as petrochemicals and coproducts is important.

The LCA appears to very focused from the WTT only, the petrochemical side could use more recognition – either in the study or (more easily) a statement in the scope.

How does the LCA account for petroleum fractions/coproducts used for petrochemicals?
For example: Refinery and Bitumen Upgrader Off Gases – used for petchem feed vs. fueling in a refinery or upgrader
How does the LCA treat the off gases? As fuel? If the off gases are used as petchem feed (as steam cracker feed to eventually make polyethylene), does the LCA consider this alternate route to be carbon positive from a WTW basis? (assuming the off gases are replaced with natural gas at the refinery/upgrader)

Other petchem examples:
LPG's – refinery fuel vs. petchem feed (steam cracker feed) vs. separation of Propane for fuel and separation of butanes for gasoline
Refinery Propylene – alky feed vs. petchem feed (eg. tetramer, cumene, polypropylene, etc)
In 2008, 15.3 Millon metric tons of propylene was produced from refineries with >90% from FCCU's – not insignificant
The presentation appears imply that all propylene is used for alkylation – I'd suggest using the average refinery RGP/Alky split
Butylenes – alky feed vs. petchem feed (eg, HPIB, comonomer, etc)
Naphtha – for reformer feed vs. petchem feed (e.g. steam cracker, etc)
Aromatics - gasoline blend vs. petchem feed (styrene monomer, cumene, paraxylene, etc)

Tiffany Groode, Associate Director, Cambridge Energy Research Associates
Would it be possible to get the figure on slide 35 in units of kgCO2e per bbl of crude processed? Or would it be possible to get the conversion factors that are needed to do that calculation?

Also can you provide the GHG emissions associated with crude transportation and the transportation of refined products?

What would be the conversion you would use for slide 33 to go from gCO2/GJ or gasoline to gCO2/bbl of crude? What is the assumption of how many gallons of gasoline is produced from a barrel of crude?

Lester Wyborny II, U.S. EPA
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What about all transportation fuels…. Including diesel?
Suggest there is a max gasoline and max diesel scenario.

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It seems that addressing the flaring of natural gas produced at oil fields could be the low hanging fruit for reducing GHG emissions in a carbon controlled world. I suggest that you present your results assuming that the flaring is no longer occuring, either the flared gas is reinjected into the oil field, or it is captured and used.

Bruce Cater, Suncor Energy Products Inc.
Have you used the protocols in ISO 14048 for the LCA analysis in this presentation?

Ted Little NCUT
It appears that you use SAGD as the representative for in situ bitumen production…
Did you look at GHG emissions from other in situ bitumen production (eg. THAI),

Kelly Finigan, EnCana
Although Jacobs mentioned it is "too late" for new cases, the lack of an Alberta / Canadian conventional crude is disappointing for comparison reasons given it is a large part of the current production and export slate (i.e. it is the baseline Alberta product). It may also be worthwhile for policy-makers to compare existing conventional production GHG attributes to in-situ - - especially given the ongoing declining production from the WCS basin and associated increases in lifting effort and water cut / treatment.

Conventional production appears to have been "modeled" in many instances - - has there been an attempt to validate actual fields against the model(s) and then to calibrate?

Cantarell: Indeed they do inject nitrogen and this should be accounted for. So should the increasing decline rate of this field. For quick reference, see Wikipedia: "Cantarell Field or Cantarell Complex is the largest oil field in Mexico and one of the largest in the world. It was discovered in 1976 by a fisherman, Rudesindo Cantarell. It was placed on nitrogen injection in 2000, and production peaked at 2.1 million barrels per day 330,000 m³/d) in 2003. Production declined rapidly after that, and by 2009 had fallen to 772,000 barrels per day (123,000 m³/d), making it Mexico's second largest oil field after Ku-Maloob-Zaap.[1]" Industry SOR data is filed with the ERCB
at http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_316_258_0_43/http%3B/ercbcontent/publishedcontent/publish/ercb%5Fhome/industry%5Fzone/alberta%5Fs%5Fenergy%5Fresources%5Fand%5Fstatistics/in%5Fsitu%5Fprogress%5Freports/2008/.
Please refer to this data in lieu of EnCana's analysis which is currently referred to in the presentation (it is much better to go straight to the data source than cite a producer's analysis).

During the session there was reference to Slide 83 showing SAGD operating at 2000psi (approximately 13,790kpa). This pressure far exceeds what we use and is higher than any other operator I'm aware of. If the 2000psi has been used for modeling, this should be validated. If pressure is intrinsic to the model, perhaps a sensitivity should be run.

Your desire to represent a "bracket" for in-situ GHG is currently based on SOR from 3.0 to 5.0. EnCana currently operates commercial-scale plants at SOR ~2.3 to 2.5 or so. If you truly want to bracket this production, you must be at or lower than 2.3. Otherwise we will have field production data outside the analysis band from the get-go. From comments during the session, I believe MEG Energy and Connacher Energy echo this concern.

Mining data was not discussed at all during the session (other than appearing as a result), but after my follow-up chat with Stefan, I'd recommend:
using a "bracket" as per in-situ production; not relying on CNRL Horizon data from an EIA as it is not representative or realistic (it is yet to produce commercial oil) - using EIA data only may be perceived as optimistic; included mine face and tailings emissions for transparency;

full cycle analysis should include the significant logistics and vehicles used getting staff, materials and supplies to the mine sites. At a minimum, the bussing to/from site, dedicated jet airplane trips to sites and camp facility operations (whether onsite or offsite) should be included;

Although "construction" and "reclamation" were not included for any "crude" source, it may be prudent for transparency and significance testing to have available the emissions associated oil sands mines for: "the construction phase" of an oil sands mine (i.e. the initial earth moving of soil/topsoil, overburden, initial tailings pond construction, early ore extraction, early steam and utility firing, etc - - currently these would not be considered "operations"). Similarly, it may be prudent to have available the estimate for emissions associated with mine reclamation and closure (may involve significant earth moving, water pumping and treatment).

Upgraders:
There are only three operating commercially (Suncor, Syncrude and Shell Scotford). Coke is a major energy source for cogen operations at Suncor. This must be included for transparency. If you "don't like" the optics of that data point, develop a bracket for upgraders. CNRL (perhaps "best in class" from an EIA perspective) is still in start up and has yet to prove it meets EIA forecasts (i.e. it is a theoretical upgrader still). This data should not be the basis of the LCA.
Kerosene / jet-B was not mentioned although is produced (Suncor)...is this included in the LCA analysis or an oversight?
Finally, Peer review: I would really recommend we have a third party (e.g. ICF, PWC, KPMG, Pembina Institute, etc) review the process, data, assumptions etc before going public with this to determine where the gaps are before it gets published.

Derril Stephenson, Viktor Energy, Inc.
I had a couple of observations:

- I think an analysis of Weyburn would an interesting add to the LCA to show the impact of injecting a CO2 EOR project using anthropogenic CO2.
- The conventional oil analysis around depth is weak.
- Reservoir pressure in most pools will be tied to depth at a gradient of maybe 0.5 to 0.75 psi/ft using 10,000 psi in a 5,000 ft. pool is to high (3 times normal frac pressure) (slide 64)
- Lifting cost vs. depth overstated (slides 68 - 70) by using constant pressure, more credible if constant gradient used.
- WOR for mature oilfields in Canada looks low (slide 71), i.e. for the large fields recently studied for you WOR is expected to reach the following shortly:
    - field 1 Areas range from 2 to 39
    - field 2 Areas range from 30 to 200
    - field 3 Areas range from 150 to 300
- Maybe the report should reflect that many mature pools run to much higher WOR
- They made a comment that SAGD steam pressure is higher than California and slide 83 shows SAGD pressure @ 2,000 psi and CA @ 700 to 1,200 psi. I think most SAGD operations are in the same pressure range as California.
- They miss two important points when the claim a 80% quality steam SOR of 5 equals a dry steam SOR = 4
- The water injected carries about half the heat that steam carries

- Much of the heat in the separated water in SAGD is recovered.

Chris Holly, Alberta Energy
What is the data and what was the source of the information used to assign GHG emissions to crude oil production for mined bitumen versus SAGD dilbit? What is the data and the source of that data for GHG emissions estimate for upgrading and refining of the three bitumen products? The chart is for gasoline, what about diesel?W hy isn't there a cogen credit for mining SCO? Does your modelling differentiate between paraffinic versus aromatic feedstocks going through the FCC?

Simon Mui, Natural Resources Defense Council, San Francisco, CA
1) Slide 25: The slide shows that production GHG emissions with mined bitumen having around 6 to 7 g/MJ of emissions. I am assuming that this is only extraction emissions and does not include upgrading emissions (e.g. at an upgrader or refinery upgrading)?

2) Also, for SAGD, does this include upgrading? For instance, NRCan's GHGenius model places SAGD (not including upgrading) at about 13 g/MJ, but with upgrading around 29-30 g/MJ. Is slide 25 consistent?

3) Slide 35: why does the dilbit upgrading emissions (assumed to be at the refinery) result in so much less emissions as opposed to treatment at a separate upgrader facility?

4) Slide 71: Why are there differences in water usage compared to the Tiax study?

5) Slide 84, Same question as #1

6) Slide 86. It seems like cogeneration of electricity would effectively offset emissions almost entirely. What are the assumptions on electricity? Is the electricity displacing what would have been natural gas generation anyhow or displacing coal? Also, if oil sands is a very significant user of natural gas (or exporter), I would recommend that secondary market effects be included in the life cycle to assess the impacts on the market using a macroeconomic modeling approach. Alternatively, when the “co-product” is of such significance that it displaces the entire emissions, it would seem better to allocate emissions based on an energy allocation approach.

7) Slide 100: Again referring back to slide 35, on first blush, it seems that the lifecycle approach would treat emissions at a stand-alone upgrader differently than the incremental emissions at a refinery. In the former, all incremental emissions are assigned to the synthetic crude oil produced (and eventually the gasoline/diesel product). However, in the refinery case, the incremental emissions associated with using the heavier crude oil is distributed across all the product streams. The approach outlined in slide 100 seems to assign the incremental emissions to the other products. For example, if a displacement method were used (as was the case for electricity cogeneration), LPG and coke could be displacing a less energy-intensity LPG and coke product from a lighter crude, and the incremental emissions assigned back to the gasoline/diesel product of interest. Could you comment on this? Based on the previous slides, it

seems the methodology mixes an energy allocation approach and a displacement approach. Both should be performed, but the methodology shouldn't mix both. I'm not sure I understand the bullet on "avoiding having to keep track of upstream burden."

Recorded Meeting Questions and Answers:

Surindar Singh, AERI - Meeting purpose is to present methodology & data, gather feedback before study is finalized. Intent is to keep study as transparent as possible with key stake holder input.

Dave Stachniak, Laricina Energy – Jacobs Consultancy is using different crudes vs. TIAX – was this purposeful? Answer: No. Crudes used by Jacobs Consultancy were selected independently. AERI plans to rationalize two separate studies when they are complete.

Catherine Laureshen, Total – Did we consider SCO as diluent? Answer: No. Just Dil-Bit.

Mike Layer, NRCAN – Did we consider diluent return to Alberta? Answer: No. We have not considered this yet. Our intent was not completely address every possible option. We have tried to bracket options with dilbit and SCO to US case.

Mike Layer, NRCAN – have we accounted for global trend in API dropping over time. Answer: No this was not included in the scope of our study. We will comment in our report on this issue.

Catherine Laureshan, Total – Does model include thermal production? Answer: No these are handled separately outside of the model.

Ed Koshka, Ivanhoe – Did we include nitrogen for Cantarel field – using 2 BCF per day, 1000 MW per day to run ASUs. Answer: No. Will follow-up with Ed after meeting.

Dave Stachniak, Laricina Energy – Did we include any Canadian light? Answer: No we did not in this study.

Ed Brost, Shell – Slide 24 – are water numbers produced? Answer: Yes. We did not look at water injection. Lifting energy overwhelms energy

Ed Koshka – Can we see input data to crude production model? Answer: Yes
Mike Layer, NRCAN – better info on venting emissions will be available as we move into future

Ted Little, NCUT - It appears that you use SAGD as the representative for in situ bitumen production. Did you look at GHG emissions from other in situ bitumen production (eg. THAI), or cogen plant. Answer: No re. THAI and yes re. cogen.

Chris Holly Alberta Energy, DOE – CA applying 15 g/MJ criteria. Does this mean some of crudes meet this? Answer: Yes.

Cameron Brown, Alberta Energy – does it seem inconsistent that CA is developing standards but CA TEOR oil has high emissions? Answer: Yes

Tom Corscadan, MEG – taking look at SORs CA vs. SAGD – 80% quality steam, put all wet steam down hole vs. 100% quality steam for SAGD. Answer: Yes this was addressed in our calculations as a percentage.

John Kenny, Alberta Environment - Are the intensity numbers normalized to reflect the varying products to make an apples to apples comparison? Or are we looking at different products? I don't think it is based on the forthcoming slides? Answer: final LCA results are normalized to GHG emissions per GJ of gasoline.

Nester, Nexen – Co-products – for example did we model coke burning in cement kilns, etc. Answer: Yes.

Tom Corscadan – Assuming coke goes into market, how do you burden someone like OPTI burning? Answer: Use actual emissions for particular fuel source. So there is more burden than a gas fired facility. Will review this further as finalize study.

Nester, Nexen – Since there are different types of crudes accounting for different qualities of crude? Answer: Yes

John Kurtz – Does model accurately and fully represent upgrading? Answer: Yes from many jobs.

Lester Wyborny II, Engineering Specialist US EPA - Currently, natural gas is used for upgrading the bitumen. However, looking towards the future as additional bitumen is being developed, perhaps other energy sources for bitumen upgrading will be used. Because Canadian natural gas supplies seem to be decreasing, perhaps two different sensitivities should be done for the energy input. One would be to shift to using bitumen for upgrading energy. The second, in a carbon controlled world, would be to use energy from nuclear power plants. I suggest assessing the bitumen upgrading process using these two other energy inputs. Answer: this is not currently in study scope of this work - will consider this as we finalize study. Jacobs has also done another study on this which will be made public.

Nester – What is GJ unit reference on our charts? Answer: GJ of RBOB

Lester Wyborny II, Engineering Specialist US EPA - It seems that addressing the flaring of natural gas produced at oil fields could be the low hanging fruit for reducing GHG emissions in a carbon controlled world. I suggest that you present your results assuming that the flaring is no longer occurring, either the flared gas is reinjected into the oil field, or it is captured and used. Answer: noted and agree

Tom Corscadan – Slide 33 – what SORs assumed. Answer: SAGD = 3, CA = 5

Catherine Laureshan – transportation – what is location? Answer: assumed PADII type refineries for bitumen based streams.

Chris Holly – Proposed LCFS 96 g/GJ – is our y-axis consistent with this functional unit of measuremen? Answer: Yes

Tiffany Groode, CERA - What would be the conversion you would use for slide 33 to go from gCO2/GJ or gasoline to gCO2/bbl of crude? What is the assumption of how many gallons of gasoline is produced from a barrel of crude? Answer: varies by crude type and product mix specifically.

Nester Zerpa, Nexen – why is dil-bit so low? Answer: diluent is going into refinery and being converted and blended into gasoline pool. Ed Koshka follow-up comment – these bars are mis-leading.

John Cortis? CARB – California LCFS is based on basket of crudes vs individual not just CA TEOR. Answer: We agree.

Ed Brost, Shell – Calif incremental natural gas is LNG. Is this considered? Answer: not part of our study. Will consider as we conclude study.

Song P. Sit, EnCana Corporation
Please check unit of flare gas because Bonny Light's flared gas exceeds produced gas

Several SAGD projects have SOR less than 3
What is the source of GHG intensity of mined bitumen (Slide 25)? We are asking for the origin of the data
CA TEOR average SOR is actually 5.05 (Slide 25).
(Slide 27) It seems that the Dilbit has too much naphtha at 40% than AB actual blend of 30%.
William, please explain how you handle refinery coke? Do you allocate the difference between coke and coal to gasoline? or just the coke burning emissions to gasoline?
Slide 30 – does SCO-Ckr emission includes emission of upgrading

Lester Wyborny, US EPA - Have you assessed why your lifecycle emissions analysis shows lower life-cycle impacts by bitumen compared to previous studies? This would be a valuable exercise for sorting out whether the previous studies did a viable analysis, and their results are driven by differing but reasonable assumptions, or if their analyses were flawed or biased in some way.

Ted Little, NCUT - Considering the attached gas (Statistics Canada 2008), illustrating decreasing NG production. There should be some qualification or weighting factor that addresses using this high quality clean fuel in transportation fuel production, especially if bitumens and heavy oils are able to use gasified asphaltenes as an energy source to offset the use of highly valued NG from outside sources. This would be particularly important if the lighter

crudes must rely on the highly valued NG resource for hydrogenation and other refinery processes. In other words, the use of produced asphaltenes out of the total yield to generate hydrogen and other power must be considered in a positive way in your model (in my opinion).

Unknown name – What do we assume for grid power? Answer – varies by region. Nat gas cogeneration power.

Gerald Bruce, MEG Energy - System boundary observation (slide 46) - Conventional crude to gasoline?What about all transportation fuels?. Including diesel? Suggest there is a max gasoline and max diesel scenario. Answer: Yes we are looking at emissions across all products including diesel.

Chris Holly, AE DOE – Slide 51 is confusing and might be misunderstood.
Keesom – life cycle emissions should be gCO2e per MJ vs. GJ

Unknown name – What flaring combustion efficiency did we use? Answer: 99%

Chris Holly – slide 81 - be careful about reporting SORs from pilot projects, Nexen comment: 8 SOR is from pilot project – actual commercial target is 3.3 SOR. Cameron Todd, Connacher comment: not many SAGD being designed for more than 3-4 SOR due to economics (2.5-3 for Connacher). Distinguish between CSS and SAGD – makes big differnec. EnCana comment: Using 3 SOR may be too conservative, they are running 2.3. Answer: We agree with comments and will review this issue and add more fidelity and clarity.

Song Sit, EnCana - Looking ahead to Slide 84, it shows mining emission of about 7 kg per GJ (bitumen?). What is the assumption of overburden to ore strip ratio? What is the diesel consumption per tonne of ore? Haul distance of ore to crusher? Haul distance of overburden to overburden dumps? Pumping distance of tailings to tailing pond? What is the slurry temperature and bitumen extraction temperature? What is the naphtha loss per barrel of bitumen and what is the fugitive from the naphtha in the tailings pond? What is the fugitive from the mine face? Answer:

Ted Little, NCUT, and Cameron Todd, Connacher – should get credit from cogen power export to grid to back out coal based power generation. Answer: we agree this is a very interesting policy issue, but we have not taken cogen credit in the preliminary LCA results bars we presented today. This is an important policy discussion.

Chris Holly, AE DOE – Comment: CARB was given information on Alberta grid and cogeneration. Every commercial SAGD project has cogen associated with it. See Athabasca Resources Committee document on web.

Lester Wyborny, US EPA - The credit that you may be able to claim for cogen should be against the marginal electricity produced, which is probably natural gas not coal. Answer: Agree

John Cortis, CARB – does use of natural gas in SAGD result in other emissions where higher carbon fuels are burned due to lack of gas availability. Answer: the scope of our study has not addressed this.

Christa Seaman, Canadian Natural Resources – comment: should include impact of co-gen in our results to be sure we are doing a scientific study vs. policy study. Don't call it a credit – say actual emissions including cogeneration. Answer: will consider this further – and we will use different nomenclature.

Bill Greenizan, Ontario Ministry of Energy & Infrastructure - One comment on slide 81 re: the Cogen credit.
I would point out that the Alberta Grid is not island – for example Alberta exports electricity in off-peak hours to B.C (a hydro based). The Cogen from oilsands is the last generator to turn off (it is commonly referred to as "must run Cogen"). In other words, at night coal generation would be backed off to minimum generation levels before the oilsands cogens.
The Alberta Grid credit calculation would have to account for imports/exports.
It gets complicated in a hurry.

Ted Little, NCUT – I am writing to just have my earlier verbal comment recorded for Jacob's benefit. No need to reiterate to group. In regards to cogen, don't only consider the electric grid contribution, but also the faction of the barrel that is used in hydrogen production via gasification of asphaltenes. In other words, no co-gen is bbl + NG use in upgraders and refiners; cogen is bbl – SG used from the bbl it was produced from… this may translate into a GHG reduction of BBL+ vs BBL- from a GHG production ration purpose. Just a thought.

Unknown – A lot of heavy crude blended into WCS. Comments? Answer: Our study scope does not include addressing every crude. We do not plan to include WCS in this study.

Lester Wyborny, US EPA - What fraction of the SAGD bitumen is being produced/upgraded using cogeneration?

Randy Armstrong, Shell Oil - Shouldn't we adjust California TEOR for co-generation in the same way we do SAGD?

Ted Little, NCUT - For the record (no need to present to group):
If you are considering in-box produced fuels as non-contributors in a refinery (as per your , you should do the same for cogen with respect to both electrical generation, hydrogen produced and steam produced (for both heat used in SAGD and hydrogen production)
Just a comment for your consideration… treat refineries and cogen upgraders (e.g., Nexen, Long Lake) in similar ways with respect to the "in the box" sources and power supplies.

Nester Zerpa, Nexen – Consider treatment of burning asphaltenes the same way we are treating coke and displacement of coal. Answer: discuss offline.

Ted Little, NCUT - Did you consider "Transportation" GHG contributions surrounding the transportation of coke to appropriate stockpiles? Would this be worth considering?

Unknown – if we are accounting for fuel to run mining operation, then we should count for fuel used to run helicopters to offshore rigs. Answer:

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April 16, 2009

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Re: Life Cycle Analysis of North American and Imported Crude Oils (March 13, 2009)

Dear Dr. Singh

Thank you for the opportunity to participate in the Jacobs information session on March 13, 2009 entitled Life Cycle Analysis of North American and Imported Crude Oils. The overall presentation was very informative. We had individuals from both the ConocoPhillips Canada Business Unit and from ConocoPhillips Research and Development join you for the call.

We view the Life Cycle Assessment work being commissioned by AERI (which includes the Jacobs work and the work by TIAX LLC and the University of Calgary) as an important initiative, which we hope will lead to a more informed discussion regarding the relative impact of greenhouse gas (GHG) emissions from the oil sands.

As suggested by you, we would like to bring forward some comments and questions that may help with the quality of the Jacobs study.

The Jacobs study seems more comprehensive than the previous study presented by TIAX on January 16, 2009. The modeling approach used by Jacobs is rational and transparent. This study has identified and captured most of the critical issues related to oil sands crude production, upgrading, and refining. The issues include steam-to-oil ratios applied in various in-situ production technologies, coke co-product generated during bitumen upgrading and refining, cogeneration of power and steam on site, as well as sulfur reduction and water treatment. Each of these issues affects the overall GHG emissions. Additionally, we have some feedback that we feel would make the Jacobs study much more valuable:

1. The study appears to use a 40/60 blend of light diluent and bitumen on a wt/wt basis to represent dilbit. This differs from commercial dilbits, which typically have a diluent/bitumen blend ratio closer to 23/77 (wt/wt). This assumption results in a higher-than-expected naphtha yield and lower-than-expected distillate, gas oil, and resid yields. We suggest using a blend ratio that is closer to 23/77.

2. We suggest a more comprehensive methodology to account for GHG emissions for coke byproduct (upgrader coke and refinery coke). The study suggests that the coke product should not be used, as its use would result in an additional GHG burden. However, there are GHG emissions associated with maintaining, transporting, and land-filling the coke. These and other factors, such as process economics and resource utilization, should also be taken into consideration in the LCA study.

3. The assumption for cogeneration of steam and power seems to have a significant and potentially positive impact on the LCA of oil sands, and should be evaluated and verified using actual operating data. There needs to be a survey on whether the surplus power from a cogen unit is used to displace grid baseload or to replace marginal electricity. Depending on which type of electricity it displaces will lead to significantly different GHG emissions scenarios.

4. We suggest some clarifications regarding the pathway selections. For example, two of the processes referenced as Steam-Assisted Gravity Drain (SAGD) actually appear to be using Cyclic Steam Stimulation (CSS) production technology. In addition, the petroleum feedstocks for conventional U.S. crude oil pathways do not include Alaskan North Slope or U.S. on-shore production. Scenario analyses for various U.S.-based crudes are necessary to represent average production efficiencies and GHG emissions.

5. The detailed analyses of input data, references, and results were not presented, making it difficult to draw any conclusions regarding the actual quality of the study. We suggest that more transparency regarding these inputs would be helpful in that some of our comments may already be addressed, but also it may be that we could provide other feedback and commentary that would result in an even higher quality of work.

Perhaps the use of a review panel (consisting of both industry and academic personnel), prior to the information session on March 13, 2009, could have addressed some of the above issues and concerns. Regardless, ConocoPhillips very much appreciates the opportunity to participate in the information sessions and we look forward to future involvement in such discussions and the opportunity to provide more constructive feedback in future. If you have any queries related to our comments, please do not hesitate to contact us for further discussion.

Regards,

Warren M. Ewert

c: Bill Keesom (Jacobs Consultancy)
Dr. Eddy Isaacs (AERI)

From McIntosh, Dwight - Syncrude
To Bill Keesom

Cc Surindar Singh

Date Mon, Jun 15, 2009 at 9:30 AM
Subject LCA comments
mailed-bysyncrude.com

Good morning,

Sorry I cannot join the conversation but I am double booked. Have to be in another meeting in a few minutes. I would like to table some thoughts for your consideration however:

1. The conventional O&G sector does not start their production chain at the producing wellhead as suggested in the study. It begins in the exploration phase which is an industry by itself with all the attendant emissions. Other studies have found the exploration phase (including dry holes, road building, camps, and directly related activities - but not the indirect activities like air travel) account for something in the range of 10% overall. This cannot be ignored, these emissions should be added to the conventional side of the equation and examined in detail for various sources. In compiling the estimates for Syncrude canada, surrently the largest oilsand mining and upgrading facility, the inventory includes all the diesel and other emissions related to every aspect of the drilling activities. The advantage in the oilsands is that we know the deposit very well and very little exploration has to be done, also the coreholes are very shallow, much less than 200 m. on average.
2. I would suggest that even beyond the current discussion of the electrical emissions displaced by cogeneration, there is a significant amount of electrical generation displaced through our use of natural gas and other cleaner generation. I also point out that the definition of cogeneration used by the study ignores the poly-generation and thermal integration that is Syncrude's major advantage over many other energy producers, and if accounted for, this wise and environmentally beneficial use of energy would show oilsand producers to be much less intensive.
3. Syncrude produces more than just crude oil and there is no normalization for other products. A conventional oil well produces mainly crude oil. Syncrude produces a long list of economic and social benefits including but not limited to commodities like electricity (as noted above not completely normalized), coke, sulfur, and even bison.

Dwight McIntosh

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