Project Title:	**Life Cycle Analysis (LCA) of GHG Emissions of Oil Sands Reference Facilities and Emerging Technologies**
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Final Report Phase 1

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Acronyms

AI: Alberta Innovates
AEMERA: Alberta Environmental Monitoring, Evaluation, and Reporting Agency
AEP: Alberta Environment and Parks
AER: Alberta Energy Regulator
AGO: Atmospheric gas oil
API: American Petroleum Institute
AR: Atmospheric residue
Bbl: Barrel
CCIR: Carbon Competitiveness Incentive Regulation
Cogen.: Cogeneration
CLRP: Christina Lake Regional Project
COSIA: Canada's Oil Sands Innovation Alliance
CSS: Cyclic steam stimulation
CWE: Cold water equivalent
EF: Emission factor
eMSAGP: enhanced Modified Steam and Gas Push
EPA: Environmental Protection Agency
ERA: Emission Reduction Alberta
FCC: Fluid catalytic cracker
FOR: Flaring-oil-ratio
GHG: Greenhouse gas
GHOST: GreenHouse gas emissions of current Oil Sands Technologies
GOR: Gas-oil-ratio
GREET: Greenhouse gases, Regulated Emissions, and Energy use in Transportation
H_2: Hydrogen
HVGO: Heavy vacuum gas oil
IOL: Imperial Oil Ltd.
LCA: Life cycle assessment
LCI: Life cycle inventory
LHV: Lower heating value
LVGO: Light vacuum gas oil
ISPP: In Situ Performance Presentation
NETL: National Energy Technology Laboratory
NFT: Naphthenic froth treatment
NG: Natural gas
OCI: Oil Climate Index
OPEM: Oil Products Emissions Model
OPGEE: Oil Production Greenhouse Gas Emissions Estimator
PADD: United States Petroleum Administration for Defense District
PFT: Paraffinic froth treatment
PRELIM: Petroleum Refinery Life Cycle Inventory Model
SAGD: Steam-Assisted Gravity Drainage
SA-SAGD: Solvent-Assisted Steam-Assisted Gravity Drainage

SCO: Synthetic crude oil
SF: Steam flooding
SGER: Specified Gas Emitters Regulation
SOR: Steam-oil-ratio
VR: Vacuum residues
WTR: Well-to-refinery
WTT: Well-to-tank
WTW: Well-to-wheel

Executive Summary

The delivery of improved environmental performance of oil sands operations requires both the development and deployment of new technologies as well as transparent methods that can be used to estimate emissions reductions over time. Existing oil sands technologies and projects have been well characterized in the public literature and open source tools are available to estimate their relative greenhouse gas (GHG) emissions intensities. These tools allow for estimates of GHG emissions across the full supply chain or life cycle (LC). That is, from extraction of bitumen through to the use of final products such as combustion of gasoline and diesel for transportation. However, these models can be further improved through evaluation and comparison with publicly available industry operating data and through feedback from industry experts. The life cycle GHG emissions intensities of new technologies can be estimated by adapting these tools by adding new functionality and data from operating projects and regulatory applications. The objective of this project is twofold: 1) to evaluate open source LC models by comparing LC GHG emissions estimates of three existing oil sands projects with publicly reported data in consultation with industry experts; and 2) to estimate the potential impact on LC GHG emissions of two new in situ oil sands technologies through comparing the estimates with those of conventionally deployed oil sands technologies. The open source models used in this project are Oil Production Greenhouse Gas Emissions Estimator (OPGEE) and the Petroleum Refinery Life Cycle Inventory Model (PRELIM), maintained by researchers at Stanford University and the University of Calgary, respectively. Through this project, the accuracy of OPGEE is evaluated by comparing OPGEE's GHG emissions intensity estimates to company-reported emissions. No evaluation of PRELIM or downstream emissions estimates was conducted as part of this study.

The GHG emissions intensities of three existing oil sands projects are estimated in this project: 1) CNRL's Horizon mining project (pathway: surface mining (naphthenic froth treatment) + upgrading + refining, modeled); 2) Imperial's Kearl mining project (pathway: surface mining (paraffinic froth treatment) + dilution + refining; and 3) MEG's Christina Lake Regional Project (CLRP) Steam Assisted Gravity Drainage (SAGD) project (pathway: SAGD + dilution + refining. The life cycle GHG emissions intensities of two new emerging oil sands projects are also estimated in this project: 1) the enhanced Modified Steam And Gas Push (eMSAGP) technology developed by MEG Energy; and 2) the Solvent-Assisted SAGD (SA-SAGD) technology developed by Imperial.

This analysis shows that when project specific input data and boundaries are aligned, the open source upstream tool (OPGEE) generates GHG emissions estimates that are within 1-4% of company reported data. When the boundary is expanded to reflect the set of activities typically considered in LC studies (i.e., expanding the boundary from direct emissions included in company reported data to also include indirect emissions from natural gas production, electricity and diluent supply, lifetime land use and lifetime tailings ponds emissions), upstream GHG emissions intensities for current oil sands pathways can increase by almost 100% (from 25.7, 70.6, and 37.9 kg CO_2eq/bbl crude to 54.7, 93.9, and 55.7 kg CO_2eq/bbl crude for Imperial

Kearl, CNRL Horizon, and MEG eMSAGP pathways, respectively). Note that each pathway produces a crude with unique properties that will have distinct downstream emissions, particularly the CNRL Horizon pathway which produces synthetic crude oil (SCO) while other pathways produce dilbit. While no evaluation of downstream activities (refining and combustion of fuels) was conducted in this project, their inclusion helps to demonstrate that emissions from upstream oil sands operations contribute between 9.6-17% of the LC emissions (507, 552, and 507 kg CO_2eq/bbl crude for Imperial Kearl, CNRL Horizon, and MEG SAGD pathways, respectively). The exercise of comparing model estimates to publicly reported data demonstrates the need for careful treatment, understanding, and interpretation of publicly reported data for use in life cycle assessment models. It also emphasizes the need for complete and transparent statements about boundaries (what activities are and are not included) in all studies and public reporting of project emissions. Regional regulatory reporting requirements may utilize boundaries that differ from LCA studies so are not always aligned with the data input needs and boundary choices when life cycle estimates are the goal.

The two emerging oil sands pathways show that there may be a potential to reduce extraction emissions if these technologies are deployed. eMSAGP shows that there is potential to reduce upstream emissions by approximately 14% below SAGD on the same reservoir and SA-SAGD has the potential to reduce upstream emissions by approximately 19% below SAGD on the same reservoir. These reductions are somewhat muted when placed on a full WTW basis (as 83-90% of LC emissions occur downstream of the extraction facilities). Over the WTW, on the same reservoir eMSAGP and SA-SAGD reduce emissions by 1.6 and 1.9%, respectively. Scaling these estimates from intensity estimates based on operating data (eMSAGP) and regulatory application data (SA-SAGD) introduces additional uncertainties. However, to provide some context, the annual emissions reductions through deployment of these technologies at the scale proposed by these companies could be on the order of 0.58 million and one million tonnes of CO_2eq for MEG's Christina Lake and Imperial's Aspen projects, respectively, compared to SAGD deployed at that project under the same conditions.

While every effort was made to model emissions for these technologies as accurately as possible, uncertainty and variability exist and should be considered when conducting LCAs. For example, sources of uncertainty include how new technologies will perform at large scale at reservoirs different from their current or proposed project sites. LCA models will also continue to have uncertainty and variability in characterizing outcomes of deploying technology to other reservoirs, processing the resulting crudes in different refinery configurations, producing different final product slates, etc. Specific sources of uncertainty in this study that merit future investigation include fugitive and land use change emissions estimates and diluent sourcing.

Several changes were made to the default settings in OPGEE as part of the customized runs to better reflect the specific projects and regional conditions of this study. These include modification of OPGEE inputs to better reflect Alberta context (rather than generic defaults employed in OPGEE, generally derived from the U.S. Department of Energy's Argonne National Laboratory's GREET model), modification of OPGEE inputs to better reflect the specific projects evaluated in this study by evaluating OPGEE's inputs relative to actual operating data, and the addition of emerging technology pathways to OPGEE that were not previously available in the model.

The accuracy and representativeness of the OPGEE model in characterizing upstream emissions from oil sands pathways generally was also improved through this comparison exercise. This includes 1) redesigning the steam generation module to allow more detailed calculations and more heat recovery potential via air pre-heaters, economizers, and blowdown water heat recovery, as well as to better characterize cogeneration units, 2) more detailed modelling of available blowdown water treatment to allow the user to input a blowdown water treatment recycling rate, 3) addition of more water treatment technologies, and 4) additional methods for modelling heavy oil dilution. These modifications have been or are proposed for incorporation into OPGEE 3.0.

Each study that has previously estimated life cycle GHG emissions intensities from fuels produced from oil sands-derived crudes is distinct in terms of its goal, scope, boundaries, data employed, projects or pathways characterized, modelling approaches used, and assumptions made throughout the study. Without some alignment of boundaries, assumptions, etc., no two studies can be directly compared (not an apples-to-apples comparison). This study presents results based on data reflective of steady-state operations for five oil sands projects and use of data that best reflects the Alberta context. While we have used the same open-source tool (e.g., OPGEE) employed in other life cycle studies of petroleum-derived crudes (e.g., Masnadi et al. 2018; Gordon et al. 2015), several changes were made to the model to both adapt the model to represent the Alberta context and to generate (in consultation with companies), the most accurate representation of their specific project operations using data available at the time of the study.

We find that, if the Alberta inputs used to adapt the OPGEE runs for the projects in this study are verified (particularly the upstream natural gas intensity), above-average performing oil sands projects could approach the global average WTR GHG emissions intensity estimated by Masnadi et al. (10.3 g CO2eq/MJ crude). A robust comparison of these oil sands projects to a global average GHG emissions intensity of crude production would require that the approach taken in this study to characterize the emissions from oil sands projects in the Alberta region be completed for all crude producing regions globally. This is outside of the scope of the current study. However, this study demonstrates the potential reduction in GHG intensities from emerging technologies compared to current projects and the impact of adopting regional emissions factors on WTR GHG intensity estimates of oil sands projects. The two emerging technologies modeled in this study (eMSAGP and SA-SAGD) can further reduce upstream GHG emissions intensities by 14 and 19% compared to a SAGD project deployed at the same reservoir. Changing the Masnadi et al. and OPGEE generic inputs and assumptions to Alberta-specific inputs reduce WTR GHG emissions intensities estimates by up to 35% (Imperial Kearl pathway). Further work is required to understand how other pathways from Masnadi et al. would be affected by similar adjustments of generic OPGEE inputs to account for regional differences. On a WTW basis, these reductions from the adoption of emerging technologies are approximately 1.6 and 1.9% of the full life cycle on a per MJ gasoline basis for eMSAGP and SA-SAGD, respectively.

The Alberta government and companies participating in this study have provided unprecedented access to both public and confidential operating data and data to better characterize the regional context that allowed for a much more robust estimate than in other jurisdictions. This can and should be done for other jurisdictions in future studies.

1. Introduction

The delivery of improved environmental performance of oil sands operations requires both the development of new technologies as well as transparent methods to estimate emissions reductions over time. Existing oil sands technologies and projects have been well characterized in the public literature and open source tools are available to assess their relative greenhouse gas (GHG) emissions intensities. The tools allow for estimates of GHG emissions across the full supply chain, life cycle (LC) or for transportation fuels, the well-to-wheel (WTW). That is, from extraction of bitumen through to the use of final products such as combustion of gasoline and diesel for transportation. These models can be further improved through evaluation and comparison with operating data and through collaboration with industry experts. In addition, the life cycle GHG emissions intensities of new technologies can be estimated by adapting these tools by adding new functionality and data from operating projects and regulatory applications. The objective of this project is twofold: 1) to evaluate open source life cycle models by comparing LC GHG emissions estimates of three existing oil sands projects with publicly reported data in consultation with industry experts; and 2) estimate the potential impact on LC GHG emissions of two new oil sands technologies. The open source models used in this project are Oil Production Greenhouse Gas Emissions Estimator (OPGEE) and the Petroleum Refinery Life Cycle Inventory Model (PRELIM), maintained by researchers at Stanford University and the University of Calgary, respectively. Through this project, the accuracy of OPGEE is evaluated by comparing OPGEE's GHG emissions intensity estimates to company-reported emissions. No evaluation of PRELIM was conducted as part of this study.

The GHG emissions intensities of three existing oil sands projects are estimated in this project: 1) CNRL's Horizon mining project (pathway: surface mining (naphthenic froth treatment) + upgrading + refining, modeled); 2) Imperial's Kearl mining project (pathway: surface mining (paraffinic froth treatment) + dilution + refining; and 3) MEG's Christina Lake Regional Project (CLRP) Steam Assisted Gravity Drainage (SAGD) project (pathway: SAGD + dilution + refining. The life cycle GHG emissions intensities of two new emerging oil sands projects are also estimated in this project: 1) the enhanced Modified Steam And Gas Push (eMSAGP) technology developed by MEG Energy; and 2) the Solvent-Assisted SAGD (SA-SAGD) technology developed by Imperial. The MEG eMSAGP pathway is modeled based on the eMSAGP project at the CLRP. Imperial's SA-SAGD pathway is defined based on publicly available data provided within its regulatory application for the proposed Aspen SA-SAGD project. The purpose of this study is not to endorse or project future performance of these technologies, but rather to estimate the GHG emissions differences between current and emerging technologies if the technologies perform as they have (in the case of eMSAGP) or are projected to (in the case of SA-SAGD) in company reporting and public datasets.

1.1 Project Context

This project was motivated by stakeholder interest in understanding open source LC models and how closely they can replicate GHG emissions for individual operating oil sands projects as well as emerging technologies being developed by the industry. This project offers the opportunity to evaluate the robustness of the LC models to estimate life cycle emissions intensities of oil sands pathways and offers opportunities to update and improve these models where appropriate. In addition, using these tools to estimate LC GHG emissions of new technologies allows for a better understanding of the role that these technologies can play in reducing GHG emissions.

LCA is a tool that can be used to evaluate the environmental impacts of a product or process from the extraction of resources through to the disposal of unwanted residuals. It has evolved rapidly in the past decade from its initial use as a decision-making tool that helps to inform policy, to become a tool for policy enforcement (e.g. low carbon fuel standards) as well as to inform funding agencies and investors that support the development of new and innovative technologies (Bergerson et al. 2019). As such, LCAs tend to have much broader boundaries of analysis than published data associated with regulatory reporting requirements. For example, SGER reported data includes emissions associated with stationary, on-site combustion, on-site industrial process emissions, flaring, fugitive, and venting, whereas in a LCA, activities such as emissions associated with off-site electricity generation and natural gas production are also typically included. This project includes detailed comparisons between reported emissions and those generated using open source tools to better understand these differences and the impact that they have on GHG emissions estimates. Life cycle results tend to be presented on a functional unit basis, that is, per unit of function or use provided by the system being studied, to provide a consistent reference to facilitate comparisons across pathways. For example, emissions from the life cycle of a transportation fuel may be presented per barrel (bbl) of crude produced, or per megajoule (MJ) of transportation fuel consumed (e.g., gasoline).

The project was led by LCA practitioners in consultation with industry experts. The project started with an initial estimate of emissions from extraction through to the shipment of the crude product at the entrance to the refinery (termed well-to-refinery, WTR) using the open source tool OPGEE and the best publicly available data as input for each of the three existing oil sands pathways. These estimates were presented to the individual company experts for feedback and discussion. Additional data and interpretation of public data were shared and the estimates updated through several iterations for each pathway. The activities associated with life cycle estimates were then estimated to provide a WTR estimate of GHG emissions intensity. In a subsequent step, the GHG emissions intensities of new technologies were then estimated using pilot and regulatory application data. Again, this was conducted in consultation with industry experts and there were several rounds of iteration on inputs and interpretation of the results. A sensitivity analysis was then conducted on the upstream results as well as the addition of downstream life cycle stages (refining, transport of fuels and combustion of transportation fuels). The results presented in this report represent the GHG emissions of these five oil sands pathways using several boundaries of analysis, and different functional units (i.e., the denominator used to present an emissions intensity estimate). All model input values, assumptions and modelling choices are documented in the main report or appendices.

1.2 Project Purpose, Scope and Deliverables

1.2.1 Project objectives

The project objectives are to:

1. Estimate life cycle GHG emissions intensities from three existing technologies: 1) CNRL's Horizon mining project (pathway: surface mining (naphthenic froth treatment) + upgrading + refining, modeled); 2) Imperial's Kearl mining project (pathway: surface mining (paraffinic froth treatment) + dilution + refining; and 3) MEG's Christina Lake Regional Project (CLRP) Steam Assisted Gravity Drainage (SAGD) project (pathway: SAGD + dilution + refining.. Data for these pathways will help to evaluate existing open source models (OPGEE and PRELIM) as well as form a baseline for comparison of emerging technologies.
2. Estimate the potential reduction in GHG emissions intensities of two emerging technologies (both SAGD-related technologies that involve light hydrocarbon co-injection with steam).

The following principles and approaches have guided the project:

- Employ open and transparent data and assumptions
- Maintain independence of the research team
- Oil sands operators will provide actual operational data for the modelling; all data provided will be either publicly available or will be made public
- Operational insights from oil sands company experts will be shared with the research team and be considered in the study
- Ensure models used in the study will be calibrated with actual operating data
- Ensure assumptions used in the modelling are consistent with the realities on the ground based on regular interaction between researchers and operators.
- Peer review: modelling results will be reviewed by the Review Panel. The Review Panel has the responsibility to raise any concerns regarding the models, assumptions, and modelling results throughout the project. The Research Team has a responsibility to address these concerns. Consensus is desirable but not required.

1.2.2 Specific tasks accomplished\

The following research tasks were carried out to accomplish the project objectives:

1. Estimate GHG emissions associated with surface mining (naphthenic froth treatment) + upgrading + refining (CNRL Horizon pathway).
2. Estimate GHG emissions associated with surface mining (paraffinic froth treatment) + dilution + refining (Imperial Kearl pathway).
3. Estimate GHG emissions associated with SAGD + dilution + refining using data from the MEG Christina Lake project (MEG SAGD pathway).
4. Estimate GHG emissions associated with MEG eMSAGP (new technology – MEG eMSAGP pathway).

5. Estimate GHG emissions associated with Imperial's SA-SAGD (new technology – Imperial SA-SAGD pathway).
6. Integrate pathways into OPGEE and PRELIM where appropriate.
7. Modify Oil Climate Index (OCI; see Gordon et al. 2015) with modelling results: Research insights and results of this project will be incorporated into the OCI as appropriate including the addition of emerging technologies.

For Tasks 1-5 (estimating GHG emissions intensities associated with five oil sands pathways), OPGEE emissions estimates were compared with company/reported data for model evaluation purposes. Based on this model evaluation, the next release of the public version of OPGEE (version 3.0) will include modifications to better represent these oil sands pathways. While the OCI employs the Oil Products Emissions Model (OPEM) to estimate refined products transport and combustion emissions (Gordon et al. 2015), for this study we employ other approaches for estimating refined products transport emissions and combustion emissions (discussed in Methods Sections 2.13 and 2.14, respectively). No changes were made to PRELIM or OPEM as a result of this study.

1.2.3 Project deliverables

Table 1-1 includes a summary of project tasks, success metrics, and deliverables.

Table 1-1. Summary of project tasks and success metrics

Task number	Task description	Success metrics
1	Estimate GHG emissions associated with surface mining (naphthenic froth treatment) + upgrading + refining (CNRL Horizon pathway).	A: Estimate GHG emissions associated with surface mining (naphthenic froth treatment) + upgrading + refining (CNRL Horizon pathway). B: Comparative analysis of OPGEE model estimates against company/reported data. PRELIM and OPEM model estimates not compared against company/reported data.
2	Estimate GHG emissions associated with surface mining (paraffinic froth treatment) + dilution + refining (Imperial Kearl pathway).	A: GHG emission estimates for the unit operations in the Imperial Kearl pathway. B: Comparative analysis of OPGEE model estimates against company/reported data. PRELIM and OPEM model estimates not compared against company/reported data.

3	Estimate GHG emissions associated with SAGD + dilution + refining (MEG Christina Lake pathway).	A: GHG emission estimates for the unit operations in the MEG Christina Lake pathway. B: Comparative analysis of OPGEE model estimates against company/reported data. PRELIM and OPEM model estimates not compared against company/reported data.
4	Estimate GHG emissions associated with Imperial's SA-SAGD (new technology – IOL advanced pathway).	A: GHG emission estimates for the unit operations in the SA-SAGD pathway. B: Comparative analysis of OPGEE model estimates against company/reported data. PRELIM and OPEM model estimates not compared against company/reported data.
5	Estimate GHG emissions associated with MEG eMSAGP (new technology – MEG Energy advanced pathway).	A: GHG emission estimates for the unit operations in the SA-SAGD pathway. B: Comparative analysis of OPGEE model estimates against company/reported data. PRELIM and OPEM model estimates not compared against company/reported data.
6	Integration of pathways into OPGEE.	Development of technical insights from Tasks 1 to 5 for OPGEE model enhancements.
7	Modification of Oil Climate Index (OCI) with modelling results: Research insights and results of this project will be incorporated into the OCI as appropriate including the addition of emerging technologies.	OCI is modified with results from the project.

2 Methods

In this study, LC (or WTW) GHG emissions are estimated for five oil sands pathways using public data where possible, validated with company expert input, and modeled in open source tools. The following sections provide an overview of the data collection approach, system boundaries, functional units, data sources and assumptions made in modelling each pathway. Additional data and assumptions are provided in Appendix A.

2.1 Research approach

The approach taken in this project is as follows:

Step 1: Research team collected public, company-specific operating data where possible and noted areas where additional data beyond that available in the public realm was required. Data was used to develop preliminary pathway well-to-refinery (WTR) GHG emissions intensity estimates.

Step 2: Preliminary pathway WTR GHG emissions estimates were presented to company experts and compared to company/publicly reported data. These preliminary pathway WTR emissions GHG intensity estimates were updated with public data supplemented with confidential company-specific data where required. Downstream modelling approaches were presented to company experts for feedback.

Step 4: Preliminary WTR and downstream results presented to Advisory Committee for feedback, including finalizing the selection of boundaries, functional units, assumptions to employ for the base case results and sensitivity analysis (e.g., indirect emission factors, refinery configuration, diluent sourcing and logistics).

Step 5: Well-to-wheel (WTW) results updated and presented to company experts for additional feedback. Iterated with company experts and Advisory Committee to finalize base case GHG emissions intensity estimates for each oil sands pathway.

Step 6: Sensitivity analysis to base case assumptions across the full WTW conducted, including estimating variability and uncertainty and differentiating between parameter variability and uncertainty (e.g., due to monthly variability in fuel consumption) and model variability and uncertainty (e.g., due to assumptions about how to credit projects for electricity exported to the grid).

Step 7: OPGEE updated, where appropriate, based on project findings. The proposed updates to OPGEE are outlined in this report in Section 3.8.

Step 8: Findings presented to Advisory Committee in a final presentation and report.

2.2 Life cycle models employed in the study

For this study, OPGEE is employed to estimate well-to-refinery GHG emissions intensities, PRELIM is employed to estimate refinery emissions. An overview of each of the models is provided below.

2.2.1 OPGEE overview

OPGEE is an open source LCA tool that estimates GHG emissions intensity from production, processing, and transport of crude oil (WTR). OPGEE estimates WTR GHG emissions intensities from all types of crudes including heavy and extra-heavy oil. The original oil sands pathways in OPGEE were developed to represent the average operating conditions for different oil sands technologies (SAGD, mining employing paraffinic froth treatment (PFT), and mining employing naphthenic froth treatment, NFT) and most default inputs for these two pathways were taken from AER statistical reports and COSIA mine templates. A heavy oil upgrading pathway was included in OPGEE based on the Oil Sands Technologies Upgrading Model

(OSTUM; Pacheco et al. 2016). Default inputs in OPGEE 2.0 for mining and SAGD pathways are compared to those employed in this study in Section 2.10 of this report. A simplified process diagram of the OPGEE model specific to mining and SAGD pathways is shown in Figure 2-1.

One of the objectives of this project is to validate the default input values used in OPGEE 3.0 and to update them if data sources of better quality are available. This validation process is undertaken in conjunction with the GHG emissions quantification with company reported data and feedback from company experts involved to identify discrepancies between public reported data and the impacts on resulting emission results.

Four types of updates are made to better represent the oil sands pathways in OPGEE:

1. Minor modifications to the modelling approach so that processes in OPGEE are more representative of SAGD operations (e.g., the addition of new steam generation equipment such as drum boilers) and current diluent sourcing scenarios. These modifications are proposed for incorporation into OPGEE 3.0.
2. Updates to OPGEE input parameters to better reflect the Alberta context (e.g., emissions from the supply of natural gas and electricity). OPGEE typically employs generic inputs that do not account for regional variability. For this study, where appropriate, inputs are updated to Alberta-specific values. These will not be incorporated into OPGEE 3.0 as OPGEE employs generic inputs and does not typically account for region-specific inputs.
3. Updates to OPGEE's generic energy inputs for each oil sands pathway (e.g., energy consumed in mining projects with integrated upgrader) to reflect recent operations by the relevant project assessed in this project. These will not be incorporated into OPGEE 3.0 because the current inputs to OPGEE are intended to be representative of typical operations within each pathway rather than the specific projects included in this study.
4. Modifications to OPGEE to enable modelling of the emerging in situ pathways (eMSAGP and SA-SAGD). These modifications are proposed for incorporation into OPGEE 3.0.

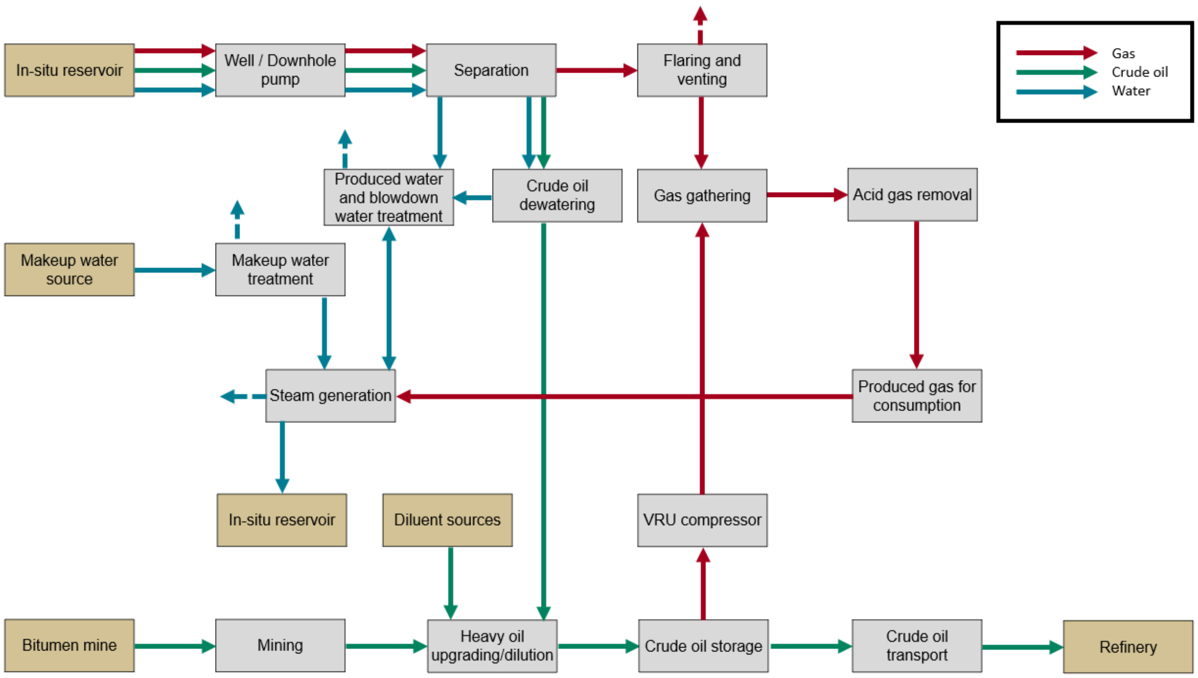


Figure 2-1. OPGEE process diagram

2.2.2 PRELIM overview

PRELIM is an open source excel-based LCA tool that estimates energy and GHG emissions intensities from petroleum refining (see process diagram in Figure 2-2; Abella and Bergerson 2012). PRELIM accounts for the quality of crude being refined and the refinery configuration. Crude assays can be selected from PRELIM's existing assay inventory or input manually into PRELIM. Ten refinery configurations can be modeled in PRELIM, representing most existing North American refineries. Four of those refinery configurations in PRELIM are considered for this analysis. Broadly, these four refinery configurations can be categorized as hydroskimming (the least processing of crude oil), medium conversion, and deep conversion (the most extensive level of refining, where even the heaviest streams of the crude are refined). PRELIM tracks the flows into and out of each process unit in the refinery as well as the emissions from each process unit so refinery emissions can be allocated to refinery products (e.g., gasoline, diesel, jet fuel, liquid heavy ends, coke) on a process-unit level, where the burden of emissions for each product is assigned based on the emissions intensity of the process units within the refinery that produce that product. Emissions can be allocated to products based on the hydrogen, mass, or energy content (lower or higher heating value) of the products. It is important to note that the configurations selected from PRELIM are typical configurations and are not intended to represent any specific refinery.

For this study, we use PRELIM v1.3, available online at https://www.ucalgary.ca/lcaost/prelim. More information about PRELIM can be found in the model documentation (Abella et al. 2019). Specific assumptions and choices to model refinery emissions in this study using PRELIM are presented in Section 2.12.

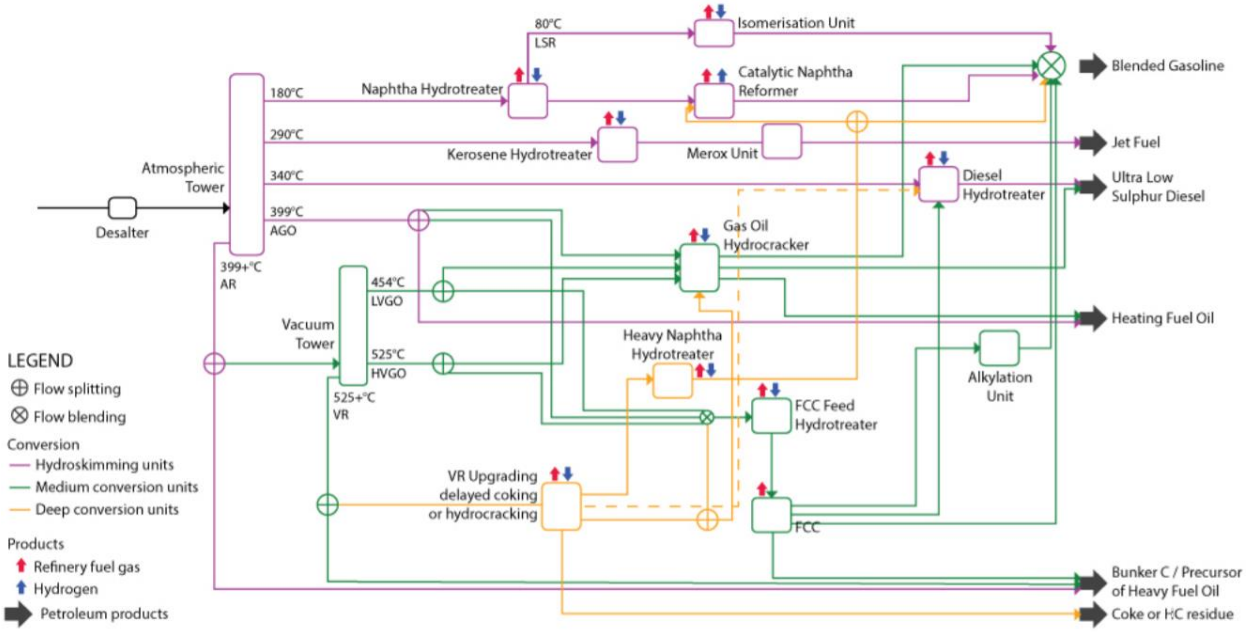


Figure 2-2. PRELIM process diagram

2.3 Study boundaries and functional units employed

Several system boundaries can be applied to the study of hydrocarbon production chains. The choice of system boundary will affect GHG emissions results. There is no unique “correct” choice for the system boundary, so clarity on the system boundary applied is important. Figure 2-3 shows the functional units and boundaries considered in this project. Results are presented for a base case, employing our best estimate of average operations and assumptions, as well as low and high sensitivity cases for each input parameter.

Upstream and crude transport (or well-to-refinery, WTR) emissions are estimated in this study using OPGEE. The OPGEE boundary includes the following activities in its system boundary: combustion emissions from fuels consumed on-site, indirect emissions associated with electricity import (or export) as well as fuel production and transport to oil sands facilities, flaring and fugitive emissions, land use change emissions, and embodied emissions from materials used on-site. Over 100 emissions sources are included in OPGEE; for more information see Masnadi et al. (2019). Refinery emissions are estimated using PRELIM and include direct and indirect emissions from fuels consumed by refinery process units (Abella et al. 2018). Refined products transport emissions are estimated using OPEM and considers in its system boundary direct and indirect emissions from fuels consumed in transporting refined products (Gordon et al. 2015). Combustion emissions (direct) are estimated using an equation presented in Section 2.14.

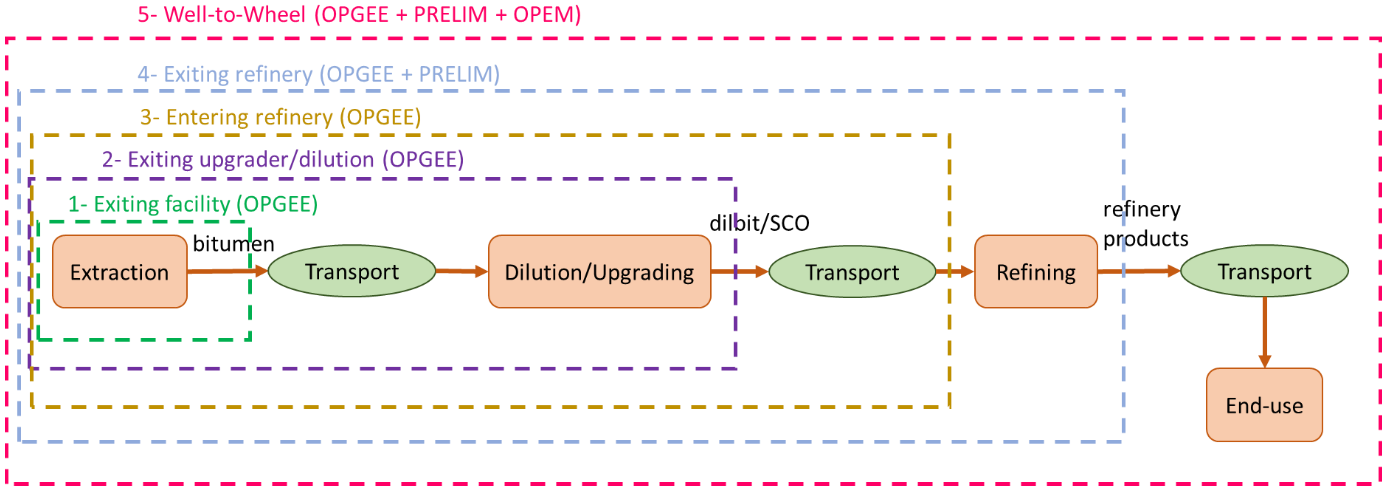


Figure 2-3. Life cycle boundaries employed in pathway characterization

The functional units and boundaries examined in the project are listed below along with the models employed in modeling the stages included in each boundary. The functional units and boundaries for the results presented in Sections 3.1 to 3.7 of this report are listed below in **bold**.

Functional units and boundaries:

1. Exiting oil sands extraction facility (OPGEE)
    a. Per MJ bitumen produced
    b. Per bbl bitumen produced
2. Exiting upgrader/dilution facility (OPGEE)
    a. Per MJ dilbit/SCO leaving facility
    b. Per bbl dilbit/SCO leaving facility (with comparison to company-reported emissions)
3. Well-to-Refinery (WTR; OPGEE)
    a. Per MJ dilbit/SCO leaving facility
    b. Per bbl dilbit/SCO leaving facility
4. Exiting refinery (OPGEE + PRELIM)
    a. Per bbl dilbit/SCO refined
    b. Per MJ refinery products (gasoline, diesel, jet fuel)
5. Well-to-Tank (WTT; OPGEE + PRELIM + OPEM)
    a. Per bbl dilbit/SCO refined
    b. **Per MJ refinery products (gasoline, diesel, jet fuel)**
6. Well-to-Wheel (WTW; OPGEE + PRELIM + OPEM)
    a. Per MJ dilbit/SCO refined
    b. Per bbl dilbit/SCO refined ("barrel-forward")
    c. Per MJ refinery products (gasoline, diesel, jet fuel)

OPGEE estimates emissions using a denominator of "functional unit" of per MJ crude (i.e., dilbit or SCO). The crude is defined, in default OPGEE settings, as the crude entering the refinery inlet gate. OPGEE results are converted from per MJ crude to per bbl of crude using lower heating values (LHVs) provided on the "fuel specs" worksheet in OPGEE (see 2.6).

2.4 Analysis timeframes

For each of the existing technologies, two sets of GHG emissions intensity results are presented in the base case:

1. Employing monthly operating data over 2015-2017 for the pathway, we present 2015-2017 results based on production-weighted average monthly operating data. Model evaluation was performed against these results for the Imperial Kearl and CNRL Horizon pathways.
2. Employing monthly operating data for 2018, we present 2018 results based on production-weighted average monthly operating data (most recent data available) which is believed to be most representative of steady-state operations. Model evaluation was performed against these results for the MEG in situ pathways, the Imperial Kearl pathway, and the CNRL Horizon pathway.

2.5 Global warming potentials

Global warming potentials (GWPs) in this study are 100-year GWPs from the Fourth Assessment Report of the IPCC (IPCC 2007): 25 for CH_4 and 298 for N_2O.

2.6 Heating values

For each pathway, one crude assay is selected to represent the crude type refined for each pathway from the PRELIM assay inventory. Crude assays include details about the properties of the crude including API gravity. By selecting a crude assay to represent the pathway, we are assigning to each pathway the API gravity reported in the crude assay. The OPGEE “fuel specs” worksheet includes a table with heating values for crudes of a range of API gravities. The corresponding LHVs for each pathway are determined based on the API gravity of the crude and the fuel specs table, and are presented in Table 2-1. The approach for selecting crude assays is described in Methods Section 2.12; crude assays are presented in Appendix A. The LHV that corresponds to the API for each pathway is presented in Table 2-1. These LHVs are general values for crudes of that density and do not represent empirical values (i.e., such as laboratory heating values generated from bomb calorimeter combustion experiments). Properties of other fuels (e.g., natural gas, diesel) consumed in each pathway are presented in Table 2-2 and are obtained from the OPGEE “Fuel Specs” worksheet Tables 3.2 (natural gas), 3.4 (produced gas), and 4.1 (diesel, gasoline). For some pathways, heating values for natural gas and process gas are updated in OPGEE based on fuel composition data provided by companies; see Appendix A for more detail.

Table 2-1. Crude oil properties for oil sands pathways.

Crude	API gravity (°)	LHV (Btu/lb)	LHV (mmBtu/bbl)	LHV (MJ/kg)	LHV (MJ/bbl)
Undiluted bitumen	8.0	17,170	6.10	39.9	6,437
Imperial Kearl dilbit	22.0	17,730	5.72	41.2	6,037

CNRL Horizon SCO	35.0	18,110	5.39	42.1	5,687
MEG SAGD and eMSAGP dilbit	23.0	17,760	5.70	41.3	6,011
Imperial SA-SAGD dilbit	19.0	17,630	5.80	41.0	6,124

Source: OPGEE "Fuel Specs" worksheet Table 1.1.

Table 2-2. OPGEE's default heating values

Fuel	Units	LHV
Natural gas	Btu/scf	941
Produced gas	Btu/scf	1,010
Diesel	Btu/gal	128,000
Gasoline	Btu/gal	112,000

Source: OPGEE "Fuel Specs" worksheet Tables 3.2, 3.4, and 4.1.

2.7 Direct emissions factors for fuels consumed

Direct emissions are defined as emissions from sources that are owned or controlled by the facility under study. The direct emissions factors employed in this study are the default values in OPGEE. OPGEE emissions factors are based on the GREET1_2016 model (Wang 2016). Direct emissions factors in OGPEE are reported on the "Emissions Factors" worksheet in Table 1.3, in g CO_2eq/mmBtu, on an LHV basis and are presented in Table 2-3, below. While mining trucks primarily consume diesel, a comparatively small amount of gasoline (approximately 5-15% of the diesel consumed on-site) is also consumed on-site and is reported for individual projects in SGER reporting (SGER 2019). As gasoline was not previously included as a process fuel in OPGEE, a direct emissions factor is obtained from the GREET1_2016 model and is added to OPGEE for this study (Wang 2016). For some pathways, direct emissions for natural gas and process gas are updated in OPGEE based on fuel composition data provided by companies; see Appendix A for more detail.

Table 2-3. Direct emissions factors for fuels consumed

Fuel	Direct emissions (g CO_2eq/MJ LHV)
Natural gas	55.3
Process gas	64.6
Diesel	74.4
Gasoline	73.2

Emissions factors in OPGEE are presented in g CO_2eq/mmBtu (LHV). For this report, emissions factors are converted to g CO_2eq/MJ (LHV).

2.8 Indirect emissions factors for fuels consumed

Indirect emissions are defined as emissions that result from the activities of the facility being studied but occur at sources outside of the facility. These include upstream or fuel cycle emissions associated with the fuels consumed at the oil sands facility (e.g., production of the natural gas used for steam generation and its transport to the oil sands facility). Indirect emissions are estimated for: natural gas and diesel (excluding diesel that is produced on-site, see description of CNRL Horizon pathway in Section 2.10.8). In this project, indirect emissions factors for natural gas, diluent, and electricity are updated from the OPGEE defaults to other sources to reflect the fuel cycle of those fuels in Alberta. These upstream emission factors assumed in the base case results are presented in Table 2-4 (on an LHV basis) and compared to OPGEE defaults ("Fuel Cycle" worksheet Table 2.5). OPGEE indirect emissions factors are obtained from the GREET1_2016 model. Sensitivity of results to assumptions about these emission factors is presented in Table 2-15.

Table 2-4. Indirect emissions factors employed in this study and OPGEE defaults

Fuel	Units	Base case emissions factors employed in this study[2]	OPGEE/GREET default[1]
Natural gas	g CO_2eq/MJ	6.4 (Senobari 2016)	14.3
Diluent	g CO_2eq/MJ	6.4 (Senobari 2016)	14.3
Diesel	g CO_2eq/MJ	18.5 (same as OPGEE default)	18.5
Gasoline	g CO_2eq/MJ	16.3 (GREET1_2016)	N/A
Electricity imported	t CO_2eq/MWh	0.696 (Alberta operating margin)[4]	0.549 (grid-average)[3]
Electricity exported[5]	t CO_2eq/MWh	0.370 (CCIR credit)[6]	0.549 (grid-average)[3]

[1]OPGEE defaults from version 3.0a_BETA of OPGEE (Masnadi et al. 2019), which were derived from GREET model version GREET1_2016 (Wang 2016). Emissions factors in OPGEE are presented in g CO_2eq/mmBtu. For this report, emissions factors are converted to g CO_2eq/MJ (LHV) or t CO_2eq/MWh (in the case of electricity). [2]Sensitivity to these parameters described in Table 2-15. [3]Grid-average emissions in OPGEE derived from GREET1_2016. [4]Alberta grid-average emissions intensity derived from (Alberta Government 2018). [5]For electricity that is exported to the grid, OPGEE credits the pathway with emissions equivalent to the grid-average emissions intensity. [6]For this study, the same approach as employed in the Carbon Competitiveness Incentive Regulation (CCIR, formerly SGER, Alberta Environment 2018) is employed, assuming that the electricity exported to the grid displaces electricity produced by a natural gas combined cycle system.

2.9 Overview of data sources and assumptions

The following section outlines the data sources and assumptions employed in estimating emissions for each oil sands pathway across the WTW. Where feasible, consistent data sources were employed across pathways and study boundaries and assumptions were aligned to facilitate comparisons across oil sands pathways. However, data available in the public realm and what company experts were able to share with the research team for this study was specific to each pathway. As a result, in modelling each pathway some decisions had to be made that were specific to that pathway, which should be taken into consideration when comparing results across pathways. Modelling differences across pathways are documented in Sections 2.10 (upstream), and 2.11 (crude transport), below. Downstream assumptions are consistent across pathways (except default refinery configuration for SCO and dilbit pathways; see Section 2.12).

2.10 Upstream data sources and assumptions

For all pathways, the inputs and assumptions listed below were employed for the base case. See Appendix A for additional background on the selection of these inputs and assumptions.

2.10.1 Energy consumption

OPGEE calculates energy consumption at each processing stage and within each facility component. Energy consumption is obtained from both public datasets in consultation with industry experts.

For mining projects, monthly energy consumption data is obtained from the AER ST39 (AER 2019a) datasets, supplemented with annual data from the SGER detailed reports, provided by the company experts upon request when available (SGER 2019).

For the MEG SAGD and eMSAGP pathways, monthly natural gas consumption and amount of electricity exported is available in annual In-Situ Performance Presentations (ISPP). Energy consumption data are extracted from graphs with a digitizer (WebPlotDigitizer, available at https://apps.automeris.io/wpd/, an online tool which extracts data points from graphs) as no tabular data is published on ISPPs. A breakdown of energy consumption by different facility process units, however, is not available at the time of this study except for monthly estimates provided by MEG of the volume of natural gas fed into their once-through steam generators (OTSG) and cogeneration plants. Where additional energy consumption data is required for the MEG pathways, the energy consumption breakdown from a report on SAGD completed by CESAR (CESAR 2019) is used to compare with more specific OPGEE model results. Energy consumption for the Imperial SA-SAGD pathway is obtained from public regulatory applications for the Aspen SA-SAGD project (IOL 2013, 2015, 2018). More details of process energy consumption and inputs specific to each pathway can be found in Section 2.10.8 of this report.

2.10.2 Flaring emissions

Hydrocarbon flaring volumes for mining pathways are obtained from the AER ST39 dataset (AER 2019a). Venting and flaring emissions for in situ pathways are obtained from AER ST60 dataset (AER 2019b).

2.10.3 Fugitive emissions from mining projects

Two types of fugitive emissions from mining projects are included in this report:

1. Mine face and other (e.g., those from pipe leaks) fugitive emissions (AEMERA 2015).
2. Fugitive emissions from tailings ponds.

Mine face and other fugitive emissions

Mine face and fugitive emissions are estimated by companies under the requirements for provincial reporting legislation for large final emitters. The Alberta Environmental Monitoring, Evaluation, and Reporting Agency (AEMERA) publishes fugitive emissions for individual oil sands mining projects over the operating years 2011-2015. Companies employ flux chamber measurements to estimate the emissions. The procedure employed in estimating these fugitive emissions is described in a report by Alberta Environment and Parks (AEP; AEP 2019). Three types of fugitive emissions are reported: mine face fugitives, fugitive emissions from tailings ponds (discussed below), and other fugitives (including those from, for example, landfill sites, separators, alternative tailings treatment or deposition areas, overburden, interburden, reject ore, topsoil storage areas and beaching area; AEP 2019). The AEMERA dataset reports fugitive emissions in tonnes of CO_2eq annually for each project. As the Imperial Kearl project began operating in 2013, only three years (2013-2015) of fugitive emissions data are publicly available from this dataset.

For the Imperial Kearl and CNRL Horizon pathways, mine face and other fugitive emissions estimates are derived from the AEMERA (2015) dataset. Fugitive emissions are converted to emissions intensities based on the annual bitumen production reported for these projects in the AER ST39 dataset (AER 2019a). Base case mine face and other fugitive emissions are the production-weighted average of fugitive emissions over the years reported in the AEMERA dataset for the Imperial Kearl and CNRL Horizon projects. Low and high mine face fugitive emissions estimates employed in the sensitivity analysis are the lowest and highest GHG emissions intensity years for each project included in this study. Mine face and other fugitive emissions estimates employed in this study are reported in Table 2-5, below.

Table 2-5. Mine face and other fugitive emissions estimates employed in this study.

	Units	Base case	Low sensitivity	High sensitivity
Imperial Kearl	g CO_2eq/MJ dilbit	0.05	0.01	0.33
CNRL Horizon	g CO_2eq/MJ SCO	0.22	0.19	0.37

Source: AEMERA (2015).

Fugitive emissions from tailings ponds

Two separate approaches are taken in the public literature for estimating tailings ponds fugitive emissions. The AEMERA employ flux chamber measurements (as above) to estimate fugitive emissions from tailings ponds. In this approach, tailings ponds emissions are equal to the emissions released by the tailings pond in the operating year under measurement. In the AEMERA dataset, fugitive emissions from tailings ponds are reported for each operating year from 2011-2015 in tonnes of CO_2eq. Burkus et al. (2014) employ a different approach, estimating life cycle emissions from the breakdown of hydrocarbons in tailings ponds and reporting these emissions in g CO_2eq/MJ bitumen produced. Additional background on the approach taken by Burkus et al. is presented below.

Tailings ponds emissions are primarily a result of the breakdown of the solvents (also referred to as diluents) employed in froth treatment (either paraffinic or naphthenic). There is a delay between when tailings are generated and when fugitive emissions are released, so the emissions from the breakdown of tailings associated with bitumen produced in a given year primarily take place in subsequent years. This is especially notable in the first few years of operation, as there is a lag time of several years between when ponds are first constructed and when significant generation of fugitive emissions begins (Yeh et al. 2010 assume a 15-year lag time). Additionally, each mine operates differently and employs diluent with distinct characteristics that often change over the life of a project. As a result, rather than using past measurements at a limited number of mines as indicators of future tailings emissions across all operating oil sands mines, Burkus et al. propose to estimate tailings ponds emissions based on the emissions that would be released from the breakdown of solvents released to tailings ponds, reported per MJ of bitumen produced at the mine.

The volume of diluent released to tailings ponds in Burkus et al. is conservatively assumed to be estimated based on the maximum allowable volume of diluent release, 4 bbl of diluent per 1,000 bbl of bitumen, based on an AER regulation enacted in 2004 (Burkus et al. 2014). They assume that 90% of total carbon in the solvent is available for fermentation. For the base case, 90% of fermentable solvent is assumed to be released as CH_4 with the remainder released as CO_2. In addition to the base case, Burkus et al. also present lower and upper limits on tailings ponds emissions assuming that all emissions from the ponds are released as CO_2 or CH_4, respectively. Results in Burkus et al. are presented per MJ of bitumen produced assuming a heating value of bitumen of 6,100 MJ/bbl. Fugitive emissions from tailings ponds are estimated for each diluent type employed in the oil sands (paraffins and naphthenes).

To consider the full life cycle of tailings emissions resulting from mining operations, we employ the fugitive emissions from Burkus et al. in this study (see Table 2-6). This is not intended to imply that the Burkus et al. approach is more accurate than the approach taken by AEMERA, but rather to reflect the different boundaries of analysis, as the AEMERA dataset represents direct fugitive emissions (and not the full life cycle) from tailings ponds released in a given operating year. Fugitive emissions from tailings ponds represent a significant source of uncertainty in the current study, discussed further in Section 2.10.5. As Imperial Kearl and CNRL Horizon employ paraffins and naphthenes, respectively, tailings emissions estimates from Burkus et al. (2014) for paraffinic diluent or naphthenic diluent are used in this study to estimate tailings emissions for the respective mining pathways. Results are converted to a per MJ dilbit or SCO basis assuming a 0.25 volumetric fraction of diluent in dilbit and an SCO/bitumen ratio of 0.85, respectively. Imperial 2015-2017/2018 and CNRL 2015-2017/2018 tailings emissions estimates in Table 2-6 are adjusted from Burkus et al. to reflect the relative volumes of solvent flared and lost to tailings ponds in the two analysis time frames based on data provided by each of the companies.

Table 2-6. Fugitive emissions from tailings ponds based on estimates by Burkus et al. AEMERA (2015) tailings ponds emissions are provided for reference.

	Units	Base case[2]	Low[3]	High[3]	AEMERA 2015 reported[4]
Burkus et al. PFT[1]	g CO_2eq/MJ dilbit	0.57	0.17	1.23	N/A
Imperial Kearl 2015-2017	g CO_2eq/MJ dilbit	0.31	0.09	0.66	0.025
Imperial Kearl 2018	g CO_2eq/MJ dilbit	0.26	0.08	0.55	0.025
Burkus et al. NFT[1]	g CO_2eq/MJ SCO	1.14	0.32	2.31	N/A
CNRL Horizon 2015-2017	g CO_2eq/MJ SCO	1.07	0.30	2.16	1.03
CNRL Horizon 2018	g CO_2eq/MJ SCO	1.46	0.41	2.96	1.03

[1]Burkus et al. estimates assume solvent loss of 4 bbl per 1,000 bbl of bitumen produced. Imperial 2015-2017/2018 and CNRL 2015-2017/2018 tailings emissions adjusted from Burkus et al. to reflect the relative volumes of solvent flared and lost to tailings ponds in the two analysis time frames based on data provided by each of the companies. [2]Base case for paraffinic and naphthenic solvents from Burkus et al. (see Table A-2 of this report). [3]Low and high ranges presented here are the lower and higher theoretical limits presented in Burkus et al. [4]Tailings ponds emissions from AEMERA (2015) for Imperial Kearl and CNRL Horizon projects. Reported in tonnes CO_2eq, converted to g CO_2eq/MJ crude using production data from the AER ST39 (AER 2019a).

2.10.4 Land use change emissions

Different methods have been employed by the small set of studies that estimate land use change emissions from oil sands projects. Most recently, Yeh et al. (2015) conducted a detailed land use change (LUC) emissions evaluation for Alberta oil fields using satellite images to estimate biomass disturbance rates of the land and carbon loss per unit area up until year-end 2009. Yeh et al. (2015) present estimates of LUC emissions for five oil sands mines and seven in situ projects (see list of projects in Table A-3). These estimates are the aggregate of land use change emissions over the life of a project for each mine in the study based on operating data up to 2009. Low and high land use change emissions estimates on a per MJ of SCO (mining) or bitumen (in situ) produced. As the CNRL Horizon mine began operating in 2009 and the Imperial Kearl mine began operating in 2013, data for these pathways employed in the Yeh et al. (2015) study is either limited (in the case of the CNRL Horizon project) or unavailable (in the case of the Imperial Kearl project). For mining projects, the production-weighted average of all mines operating as of 2009 is employed as the base case LUC emissions estimate, with the sensitivity analysis encompassing the lowest and highest emissions intensity estimates across all mining projects included in their study. Land use emissions from Yeh et al. are adapted in this study to represent the same functional units as employed for mining pathways in this study, g CO_2eq/MJ dilbit (Imperial Kearl) or SCO (CNRL Horizon) on a lower heating value basis, assuming a 0.25 volumetric fraction of diluent in dilbit.

Yeh et al. (2015) report that for in-situ projects, the production-weighted average of LUC emission is 0.56 – 0.89 g CO_2e/MJ bitumen. For the base case, a median value of 0.73 g CO_2e/MJ bitumen of the range is applied. In this study, in situ LUC emissions are converted to g CO_2eq/MJ dilbit (lower heating value) assuming a 0.25 volumetric fraction of diluent in dilbit.

An earlier study, the first to comprehensively estimate LUC and fugitive emissions from oil sands projects was Yeh et al. (2010). They report disaggregated land use, tailings, and fugitive emissions for mining projects. Yeh et al. (2010) results were the basis of land use and fugitive emissions in OPGEE 2.0. In OPGEE 2.0, LUC emissions are reported for each of low, moderate, and high carbon stock ecosystem richness as well as for each of low, moderate, and high intensity development. Land use change emissions employed in this study are compared to the fugitive and LUC emissions employed for oil sands pathways in OPGEE 2.0 and are presented in Table 2-7. For OPGEE 2.0, moderate LUC emissions intensity estimates are derived by selecting moderate habitat disturbance and moderate intensity development in the model for each pathway (see OPGEE documentation Section 4.2.2.3 for details on the approach taken in OPGEE 2.0; El-Houjeiri et al. 2018). Low and high LUC emissions intensities are derived when both low and high carbon richness and development intensity are selected in OPGEE 2.0, respectively.

Table 2-7. Comparison of land use change emissions employed in this study to those employed in OPGEE 2.0 (g CO_2eq/MJ crude).

	Land use change Base case (low-high)	
	This study	OPGEE 2.0[1]
Imperial Kearl	1.25 (0.53-2.00)	1.72 (1.21-2.87)
CNRL Horizon	2.09 (0.88-3.33)	1.72 (1.21-2.87)
In situ pathways (SAGD, eMSAGP, SA-SAGD)	0.72 (0.56-0.89)	1.26 (0.03-6.47)

[1]OPGEE 2.0 base case land use emissions presented in this table assume moderate carbon richness and moderate intensity development. Results are presented per MJ of dilbit for Imperial Kearl, per MJ of SCO for CNRL Horizon pathway, and per MJ bitumen for the in situ pathways (MEG SAGD, MEG eMSAGP, Imperial SA-SAGD).

2.10.5 Uncertainty in fugitive and land use change emissions estimates

Land use change GHG estimates are highly uncertain. Land use footprints are estimated in the sources employed using satellite images of a limited number of sites and allocated to individual bbl (or MJ) of bitumen produced based on estimates of the total bitumen that is expected to be recovered over the life of those projects. Assumptions need to be made to use the land use footprints to estimate carbon emissions from the estimated land disturbed, and total bitumen production for a project is dependent on several factors, including, but not limited to, reservoir conditions, technologies employed for bitumen production (including the adoption of new technologies that increase bitumen recovery rates, and project economics towards end of life). Additional assumptions are required to estimate LUC emissions for the projects included in this study, none of which are included in LUC studies available in the public literature at the time this study was completed (November 2019). Tailings ponds emissions are highly dependent on the volume of diluent that is released into tailings ponds, which since 2014 have been limited to 4 bbl per 1,000 bbl of bitumen (Burkus et al., 2014), but which vary across projects and over time.

The current data sources employed in this study to estimate fugitive and LUC emissions were several years old at the time of completing the study (most recent report was from 2015) and may not reflect recent endeavors by the industry to increase bitumen recovery rates and reduce both the area of land disturbed and the impacts of tailings ponds. As a result, LUC estimates in this report are conservative estimates and are likely to decrease both as efforts continue to reduce these impacts and as better data for measuring these impacts becomes available. For example, efforts are currently underway to decrease the footprint of oil sands facilities, and between 2012 and 2017, the average footprint of in situ oil sands facilities participating in one COSIA initiative has decreased from 0.337 hectares of land use per hectare of reservoir accessed to 0.314 hectares per hectare (COSIA 2019). Another program is currently underway that involves continuous monitoring at oil sands mines to improve the accuracy of fugitive emissions measurements. No public data is currently available that reflect these improvements. Fugitive and LUC emissions estimates in this study represent the best available data at the time of completion of this study. We have attempted to reflect the uncertainty in these estimates by including a broad range of emissions intensity estimates in the sensitivity analysis for these parameters where appropriate (see discussion of downstream sensitivity analysis parameters in Section 2.10.9 and Table 2-14).

2.10.6 Miscellaneous emissions

Default runs for OPGEE include a 0.5 g CO_2e/MJ crude miscellaneous emissions estimate, to account for small sources of emissions not quantified in OPGEE due to their small contribution (<0.01 g CO_2e/MJ) to WTR emissions. This miscellaneous emissions estimate was not included in the oil sands pathways for the following reasons:

- Oil sands projects generally require an order of magnitude fewer wells for the same production volume as other formations which would affect the misc. emissions assumptions. The 0.5 g CO2e/MJ value was selected in OPGEE to represent a conventional site, which may not be representative for oil sands projects.
- In situ projects already include many of these sources because they track most of what they consume on-site e.g., electricity consumed in drilling wells. Oil sands also have relatively high recovery rates (~90% for mining and ~70% for in situ), much higher than some other petroleum sites. As a result, an appropriate number for a conventional project may not be appropriate for an in situ oil sands project.
- For mining projects, all fuels consumed on-site are included in SGER/AER reporting boundaries so are included in the existing study boundary.

2.10.7 Diluent sourcing and logistics

For the base case, a hybrid diluent recycle case is assumed (see Figure 2-4) where diluent is sourced from two locations: 1) 38% of diluent is recovered at the refinery and sent via pipeline back to oil sands projects via a diluent return pipeline, and 2) 62% of diluent is locally-sourced natural gas condensate (with the same upstream emissions factor as natural gas, 6.4 g

CO_2eq/MJ). This hybrid recycle case is representative of the fraction of diluent that was sent as dilbit to PADD2 that is exported back to Canada in 2018 (determined from heavy oil exports to PADD2 and pentanes-plus imports from PADD2 to Canada using U.S. EIA sales data, see Table 2-8). At the time of this report, no public information was available to indicate how pentanes plus is produced in PADD2 and is a source of uncertainty in this analysis. We thus explore a range of possible options for producing pentanes plus in the sensitivity analysis. In the base case, we assume that the most likely process for producing this diluent is after a crude is processed at the refinery rather than being removed immediately after the distillation column. We therefore assume for the base case that diluent is produced at the refinery by separating a pentanes plus stream after the isomerization unit but prior to blending. An upstream emissions factor for pentanes plus production is assigned to this stream. This is equivalent to PRELIM's estimate for producing pentanes plus from a given dilbit, as well as the emissions associated with transporting that product from PADD2 to oil sands projects via pipeline. How this was modeled in PRELIM is described in Section 2.12.1.

The 38% diluent sourced from PADD2 represents industry-wide dilbit export and diluent import. Individual operators may purchase diluent from different sources. MEG sources their diluent from the following sources: 45% is purchased from PADD2 refineries, 5% is sourced from local refineries, and 50% is sourced from locally produced condensate. For this study, the industry-wide diluent recycling rate is employed across all dilution pathways to maintain consistency across pathways.

Table 2-8. 2018 U.S. Import of Canadian heavy crude and diluent return

Region	Imports of 19-25^o API gravity crude from Canada with >2% sulfur[1] (1,000 bbl/day)	Volume of diluent imported[2] (1,000 bbl/day	Pentanes-plus export (1,000 bbl/day)[3]	Diluent return estimate (vol. fraction)
U.S. to Canada	2,354	659	179	0.27
PADD1	44	12	0	0
PADD2	1,656	464	174	0.38
PADD3	382	107	0	0
PADD4	206	58	0	0
PADD5	66	19	0	0

[1]Source: U.S. EIA 2019. [2]Calculated from heavy oil imports, assuming vol. fraction of diluent in dilbit of 0.28. [3]Source: U.S. EIA 2019.

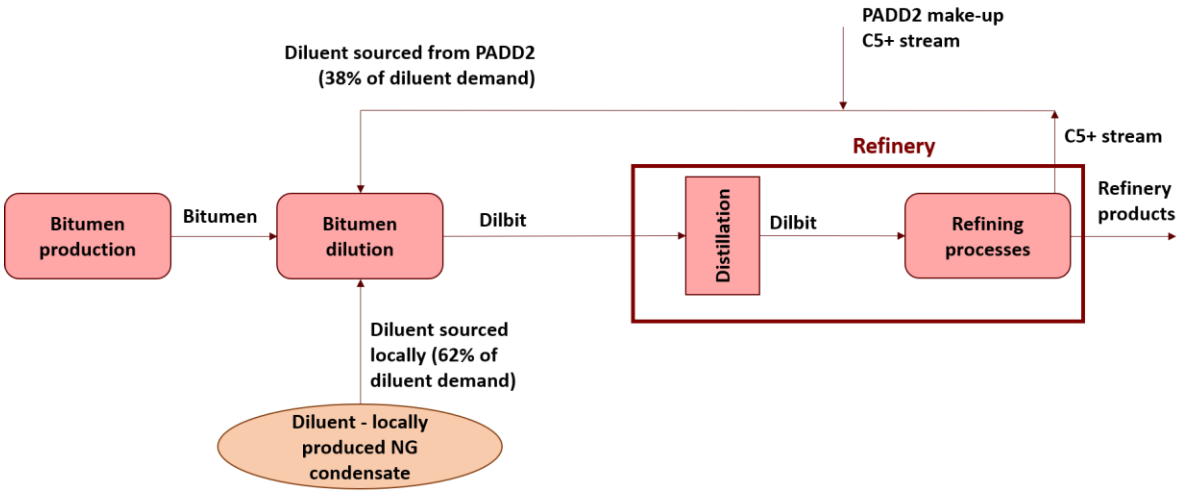


Figure 2-4. Hybrid diluent recycle case assumed for base case

2.10.8 Pathway-specific data and assumptions

Data sources and assumptions specific to each oil sands pathway are described below. A detailed list of all OPGEE inputs modified for each pathway is presented in Appendix B. Note that units in the tables below are aligned with the units employed in OPGEE where feasible, including the functional unit for different input parameters (e.g., whether inputs are presented per bbl bitumen, dilbit, or SCO).

Imperial Kearl pathway

Two separate model runs are completed for the Imperial Kearl project: one employing 2015-2017 production-weighted average monthly operating data and another employing 2018 production-weighted average monthly operating data. Process energy consumption data input to OPGEE for the Kearl pathway is presented in Table 2-9. This data is used to update OPGEE's mining and energy inputs table PFT column on the "bitumen mining" worksheet (cells B39:N46). Data for estimating energy consumption for the Kearl pathway are derived from monthly operating data reported in the AER ST39 dataset (AER 2019a), except for diesel and gasoline consumption (not reported in the ST39) which were obtained directly from Imperial based on data collected for reporting their emissions under the SGER/CCIR. Existing inputs for the mining PFT pathway in OPGEE (from the "bitumen mining" worksheet) are presented alongside the Kearl-specific data in Table 2-9 for reference. Flaring is input manually into OPGEE (no default provided for mining pathways) so no OPGEE default exists for that input. While the original OPGEE model did not include a gasoline consumption parameter for oil sands mining projects, some gasoline is consumed at mining sites. This parameter has been added to OPGEE along with supply chain and combustion emissions for gasoline, obtained from the GREET1_2016 model (Wang 2016; see documentation in Table 2-4).

Table 2-9. Mining process energy consumption and flaring for Imperial Kearl pathway

Parameter	Units	OPGEE default PFT	2015-2017 average (range)	2018 average (range)

Diesel fuel use	gal diesel/bbl bitumen	0.5	0.55[2] (0.44 - 0.66)	0.53[2] (0.42 - 0.64)
Natural gas use	scf/bbl bitumen	415	551[1] (442 - 661)	480[1] (375 - 625)
Electricity use	kWh/bbl bitumen	19.9	18.6[1]	18.4[1]
Electricity gen.	kWh/bbl bitumen	12.2	5.4[2]	6.1[2]
Net electricity imported	kWh/bbl bitumen	7.6	13.2[2] (9.5 - 17.3)	12.3[2] (11.0 - 13.9)
Flaring-oil-ratio	scf/bbl bitumen	N/A[3]	17.9[2] (14.3 - 21.4)	18.6[2] (8.6 - 19.2)
Gasoline use	gal/bbl bitumen	N/A[3]	0.022[1] (0.018 - 0.026)	0.025[1] (0.020 - 0.030)

Vol. fraction of diluent for Imperial Kearl pathway is 0.25 and 0.28 for the 2015-2017 average and 2018 average, respectively. [1]Total volume of diesel and gasoline consumed from Imperial's SGER and CCIR reports (calculated from the quantification methodology provided in Alberta Climate Change Office 2018). Ranges for sensitivity analysis are determined by adjusting diesel consumption +/- 20%. [2]Natural gas, process gas, and electricity data from AER ST39 (AER 2019a). Ranges for sensitivity analysis are 80% confidence intervals based on monthly variability in AER data. [3]Parameter added to OPGEE for this study, no default exists.

CNRL Horizon pathway

Two separate model runs are completed for the CNRL Horizon pathway: one employing 2015-2017 production-weighted average monthly operating data and another employing 2018 production-weighted average monthly operating data. Process energy consumption data input to OPGEE for the CNRL Horizon pathway is presented in Table 2-10 (mining and extraction) and Table 2-11 (upgrading). This data is used to update OPGEE's Mining and Energy Inputs Table on the "bitumen mining" worksheet (cells B39:N46) and OPGEE's Upgrading Data Table delayed coking column on the "heavy oil upgrading" worksheet (cells H38:N59). The AER ST39 dataset (AER 2019a) reports process energy consumption for the entire mine site, so for the CNRL Horizon project which has an on-site upgrader, process energy consumption is not disaggregated between mining and upgrading. As OPGEE models mining and upgrading separately, additional steps were taken to disaggregate the mining and upgrading data for CNRL. Detailed SGER/CCIR reports were provided by CNRL for each year from 2012 to 2018. For select years (2015-2018), CNRL has reported their facility emissions disaggregated between mining and upgrading. Where appropriate, the AER ST39 data has been supplemented with the SGER/CCIR data to facilitate this disaggregation between mining and upgrading.

Diesel consumed on-site was obtained from the SGER reports. CNRL also produces diesel at their upgrader that is consumed on-site as a fuel. Diesel produced on-site that is also consumed on-site is reported to the AER ("SCO fuel use" in the AER ST39 dataset; AER 2019a). The fraction of diesel that the Horizon project consumes that is produced on-site is estimated by dividing the AER-reported data for on-site diesel produced that is consumed on-site by the total diesel consumption in that year reported in the SGER reports. No upstream emissions are allocated to diesel that is produced and consumed on-site as these emissions are already accounted for in the total process energy consumption reported in the AER and SGER datasets.

Existing inputs for the mining NFT pathway (for mining and extraction) and the delayed coking pathway (for upgrading) in OPGEE (from the "bitumen mining" worksheet) are presented alongside the Horizon-specific data in Table 2-10 for reference. On-site flaring allocated to mining is input manually to OPGEE (no default provided for mining pathways) so no OPGEE default exists for that input. The Horizon extraction facility employs exclusively waste heat from the upgrader to extract bitumen from the mined oil sands material so natural gas demand for the Horizon mine is significantly lower than the default NFT pathway in OPGEE (58.2-61.6 scf/bbl bitumen versus 304 scf/bbl bitumen for the CNRL and OPGEE default NFT pathways).

Table 2-10. Mining process energy consumption and flaring for CNRL Horizon pathway

Parameter	Units	OPGEE default NFT	2015-2017 average (range)	2018 average (range)
Diesel fuel use	gal diesel/bbl bitumen	0.5	0.76[1]	0.54[1]
Natural gas use	scf/bbl bitumen	304	58.2[2]	61.6[2]
Electricity use	kWh/bbl bitumen	18.0	11.5[2]	6.0[2]
Electricity gen.	kWh/bbl bitumen	18.1	8.2[2]	3.9[2]
Net electricity imported	kWh/bbl bitumen	-0.2	3.3[2]	2.1[2]
Fraction electricity generated on-site	Fraction	N/A[3]	0.7[3]	0.7[3]
Gasoline use	gal/bbl bitumen	N/A[3]	0.11[1]	0.051[1]
Process gas use	scf/bbl bitumen	N/A[3]	97.1[2]	68.5[2]
Fraction diesel produced on-site	Fraction	N/A[3]	0.55[4] (0-1.0)	0.93[4] (0-1.0)

[1]Total volume of diesel and gasoline consumed from SGER report (based on approach documented in the SGER Quantification Methodologies document, Alberta Climate Change Office 2018). Ranges for sensitivity analysis are 80% confidence intervals based on monthly variability in SGER/CCIR data. [2]Natural gas, process gas, and electricity data from AER ST39 (AER 2019a); allocation to mining and upgrading taken from calculations done by CNRL as part

of their SGER reporting (Alberta Environment 2019). Ranges for sensitivity analysis are 80% confidence intervals based on monthly variability in AER data. [3]Parameter added to OPGEE for this study, no default exists. [4]Total on-site diesel production that is consumed on-site from AER ST39 (AER 2019a). Based on SGER/CCIR and AER-reported diesel consumption and production, respectively, we calculate the fraction of diesel consumed that is produced on-site. For the sensitivity analysis, this factor is varied from 0-1. Units presented are those employed in OPGEE.

Table 2-11. Upgrading process energy consumption and flaring for CNRL Horizon pathway

Parameter	Units	OPGEE default delayed coking	2015-2017 average (range)	2018 average (range)
API gravity of resulting upgraded product output	deg API	33.2	35.0	35.0
Process gas (PG) yield per bbl SCO output	scf/bbl SCO	501	491	404
- Fraction PG to self use - Heating (W/O cogen)	Fraction	0.65	0.54	0.40
- Fraction PG to self use - H2 gen	Fraction	0	0.0	0.0
- Fraction PG exported	Fraction	0.33	0.41	0.58
- Fraction PG flared	Fraction	0.025	0.048	0.014
Coke yield per bbl SCO output	kg/bbl SCO	43	41.0	36.6
- Fraction coke to self use - Heating	Fraction	0.11	0.0	0.0
- Fraction coke exported	Fraction	0	0.0	0.0
- Fraction coke stockpiled	Fraction	0.89	1.0	1.0
Electricity intensity	kWh/bbl SCO	5.45	13.7	7.09
- Fraction electricity self-generated with cogen	Fraction	0.5	0.66	0.68
- Cogenerated heat as steam	mbtu/bbl SCO	12	21.2	21.2
- NG to cogen unit	scf/bbl SCO	32	56.6	56.3
Natural gas intensity (W/O cogen)	scf NG per bbl SCO	337	589	620
- Fraction NG - Heating (W/O cogen)	Fraction	0	0.47	0.51
- Fraction NG - H2	Fraction	1.0	0.53	0.49

Cogen turbine efficiency	Fraction	0.31	0.30	0.30
Cogeneration steam efficiency	Fraction	0.40	0.40	0.40
Steam boiler efficiency	Fraction	0.8	0.80	0.80
SCO/bitumen ratio	Fraction	0.9	0.85	0.86

[1]Natural gas, process gas, coke, and electricity data from AER ST39 (AER 2019a); allocation to mining and upgrading taken from calculations done by CNRL as part of their SGER reporting (Alberta Environment 2019). [2]Turbine and boiler efficiencies are OPGEE defaults. SCO/bitumen ratio from AER ST39 (AER 2019a).

MEG Christina Lake SAGD and eMSAGP pathways

MEG CLRP started operations in 2008 as a SAGD project and MEG initiated its pilot of enhanced and Modified Steam and Gas Push (eMSAGP), a new technology that involves co-injection of natural gas with steam in December 2011. For each well, eMSAGP is usually deployed after achieving 30% of oil recovery via SAGD. In addition, eMSAGP involves “infill wells” being installed between producing well pairs to further increase recovery rate. The initial SAGD operations have an average SOR of 2.6. After switching to eMSAGP, the remaining oil can be recovered at an SOR as low as 1.3, enabling an overall lifetime SOR of 2.0 (MEG CLRP 2019).

eMSAGP has been proven at commercial scale and is not considered pilot-level as of 2018. With reduced steam requirements in each well, MEG is able to divert the freed-up steam into new wells to further increase production. In the first of quarter of 2019, MEG’s average fieldwide SOR was 2.20 due to expanded implementation of eMSAGP. There were 177 electric submersible pumps (ESP) and 95 rod pumps in operation (MEG ISPP 2019). ESPs are installed with SAGD producing pairs and rod pumps are installed at eMSAGP infill wells. Therefore, it is inferred that over half of CLRP wells have been converted into eMSAGP wells. The conversion rate is expected to grow with increasingly limited SAGD development and fieldwide SOR is expected to further decrease.

The SOR and other operational data published on ISPP is representative of the CLRP current operations and is taken as parameters for modeling eMSAGP, considering that the two technologies are expected to continue to co-exist in the future with further plan of production expansion.

MEG CLRP operations are assumed to be nearly purely SAGD prior to 2014, as the eMSAGP pilot was initiated in December 2011 and had limited impact on overall operations prior to the start of 2014. To better estimate the emission reduction impacts of eMSAGP, 2018 operational data (production rate, diluent fraction, etc.) are assumed for modeling MEG’s SAGD base case except for SOR and GOR. In 2013, CLRP fieldwide SOR was 2.57 (MEG ISPP 2014). Thus, a slightly greater SOR of 2.6 (to remove the limited impact of 2013 eMSAGP deployment) is assumed for MEG to continue SAGD practice into 2018. The SOR 2.6 is a theoretical value for 2018 CLRP SAGD operations assuming a similar rate of new well development in 2013 and 2018 and unchanged reservoir characteristics across years of oil recovery. In addition, using the GOR from 2018 operational data is inappropriate because eMSAGP involves natural gas injection and recycling. The GOR used for modeling eMSAGP does not only reflect the gas content of the heavy oil in Christina Lake, but also the gas handling processes exclusive to eMSAGP. For the SAGD base case, a GOR of 5 from the project application is assumed to better characterize the property of the heavy oil (MEG 2008). Further references to these assumptions can be found in Table 2.11.

Table 2-12. Summary of data sources and assumptions employed in characterizing GHG emissions from MEG Christina Lake pathway

Parameter	Units	SAGD base case[1]	2015-2017 average eMSAGP[2] (range)	2018 average eMSAGP[3] (range)
Bitumen flowrate[4]	bbl/day	81,720	79,830	81,720
SOR[5]	m^3 CWE/ m^3 bitumen	2.60 (2.34 - 2.86)	2.38 (2.14 - 2.62)	2.30 (2.07 – 2.53)
GOR*[6]	m^3/m^3	5	40	72
Diluent fraction in dilbit*[7]	volumetric fraction	0.27	0.27	0.27
Fraction of steam generated with cogen[8]	volumetric fraction	0.5 (0.45 – 0.55)	0.5 (0.45 – 0.55)	0.5 (0.45 – 0.55)
Import gas and produced gas composition and properties	-	Tested by Maxxam and reports provided by MEG; note that produced gas in the SAGD base case is assumed to have a composition of gas fed into OTSGs*	Tested by Maxxam and confidential reports provided by MEG*	Tested by Maxxam and confidential reports provided by MEG*
Volume of import natural gas for injection*	10^3 m^3/d	N/A	570	1,170
Gas turbine specs[9]	-	999°F exhaust temperature, 32.7% generation efficiency (adjusted to 30% efficiency to account for wear and tear after 10 years of operation; the additional 2.7% of input power is partitioned to be part of increased air enthalpy for		

		steam generation via HRSG), 136 btu/lb exhaust specific power
Temperature and pressure of water/emulsion streams[10]	%	Design parameters taken from MEG Phase 3 Application submitted to AER in 2008

*Private data provided by MEG; [1]SAGD base case scenario is developed to be based on historical SAGD operational data; [2]Transition period from SAGD and eMSAGP; [3]MEG reached steady state of eMSAGP operations in 2018 and thus SAGD base case is also partially developed based on 2018 operational data for comparison purposes; [4]Source: AER In-situ water publication; [5]Calculated from steam generation and bitumen production published on AER In-situ water publication; [6]Assumption made based on historical comparison is applied to SAGD base case because with co-injection of natural gas required by eMSAGP operations, it is difficult to dissociate solution gas from recovered natural gas for injection. For the two eMSAGP cases, GOR is defined as the ratio of total gas recovered and production. Volume of gas recovered is provided by MEG; [7]Source: MEG. Note that publicly available source (MEG 2008) indicate the fraction to be 0.398, which departs significantly from the actual operation; [8]Source: 2017 MEG Annual Information Sheet; [9]Source: Specs for GE 7E-EA 85MW available on GE website; [10]Source: MEG Phase 3 Application.

Imperial SA-SAGD pathway

Imperial's Aspen project is an in-situ oil sands development project that was initially proposed as a steam assisted gravity drainage (SAGD) project in 2013 (IOL 2013). After conducting a pilot project (IOL 2015) to assess an emerging in situ oil sands extraction technology, namely solvent-assisted SAGD (SA-SAGD), the proposed extraction and recovery method at Aspen was updated in 2015 to SA-SAGD. The project application was updated again in 2018 to include further improvements in the SA-SAGD process design (IOL 2018). The addition of solvent to the injected steam further reduces the in-situ oil viscosity thereby increasing bitumen rates and reducing the steam-oil ratio. Imperial anticipates that on a per barrel of bitumen production basis, SA-SAGD will reduce steam and water requirements, fuel gas consumption and greenhouse gas (GHG) emissions (IOL 2015). The most recent parameters from the project application amendments are used in this study and for parameters that are not changed in the updated version, parameters from previous project applications are used.

This study evaluates the effect of employing SA-SAGD technology for oil sands extraction on total GHG emissions of the extraction process and compares those emissions to the GHG emissions of a SAGD process under similar conditions (i.e., operating in the same reservoir: SAGD SOR is assumed to be 2.3 (IOL 2013), the remainder of the inputs are assumed to be the same; no solvent injection is assumed). Aspen SA-SAGD project is not operational yet; therefore, in the absence of historic operational data, design data presented in Aspen project application documents (IOL 2013, 2015, 2018) are used to estimate GHG emissions for SAGD and SA-SAGD pathways. In the updated design, evaporators replace the chemical water treatment process for produced water treatment, and steam generation occurs via drum boilers instead of Once Through Steam Generators (OTSGs). Cogeneration is used for producing 40%

of the steam requirement. Within the application, on-site electricity consumption is assumed to be equal to electricity generated in the cogeneration unit (net zero electricity import/export for both SAGD and SA-SAGD pathways; IOL 2018).

In the SA-SAGD pathway, the same hydrocarbon liquid (assumed to be condensate in this study) is used for co-injection with steam and for diluting the extracted product (which consists of bitumen and part of the injected diluent that is recovered along with bitumen and not lost to the reservoir). The diluent fraction in the dilbit is assumed to be 25% (volume fraction) for both SAGD and SA-SAGD pathways. According to the process mass balance in the project application, in the SA-SAGD pathway, 89.4% of the injected diluent is recovered with bitumen and it contributes to 72% of the diluent in the final dilbit stream (IOL 2018). For modelling SA-SAGD pathway in OPGEE, energy consumption for converting diluent into vapor for co-injection with steam is neglected as it is a very small amount compared to energy consumption required for steam generation.

Forty percent of required steam is assumed to be produced in a cogeneration unit that consists of gas turbine generators (GTGs) and drum boilers, and the remaining sixty percent is produced via separate drum boilers (IOL 2018). In the cogeneration unit, approximately 35% of energy input to HRSG is provided by the exhaust stream from gas turbine and the remaining 65% is provided by duct firing (this assumption is made after consulting with Imperial Oil). The energy efficiency of the drum boilers (mmBtu steam output/mmBtu LHV fuel input) is comparable to OTSG energy efficiency according to the literature (Gas Technology Institute 2017). Therefore, similar energy balance calculations are used in OPGEE for OTSG so this is used for drum boiler energy calculations. However, “best estimate” data provided by Imperial suggests a shell loss of 1% in drum boilers as opposed to 4% shell loss assumed in OPGEE default inputs.

OPGEE estimates fugitive emissions for SA-SAGD pathway as 0.028 gCO2e/MJ dilbit, however, since the project application provides a more specific fugitive emissions estimate equal to 0.022 gCO2e/MJ dilbit (IOL 2018), we input fugitive emissions manually in OPGEE for this pathway.

Land use emissions are estimated based on Yeh’s paper as discussed in section 2.11.3. According to the numbers reported by Imperial oil, SA-SAGD technology can increase bitumen recovery rate by approximately 9% compared to SAGD technology (IOL 2013), therefore, the effect of increased bitumen recovery rate via SA-SAGD extraction technology compared to conventional in-situ extraction technologies such as SAGD is considered when using gCO_2e/MJ bitumen land use emissions intensity.

The main OPGEE parameters affecting GHG emissions of SA-SAGD pathway are listed in Table 2-13 below. Note that this is based on the regulatory application for one phase of the Aspen project.

Table 2-13. Summary of data sources and assumptions employed in characterizing GHG emissions from Imperial SA-SAGD pathway

Parameter	Units	ASPEN SAGD Reference Case[1] (range)	ASPEN SA-SAGD[1] (range)
Bitumen flowrate	bbl/day	81,000	81,000
Bitumen API gravity	°API	8	8
SOR	m^3 CWE/ m^3 bitumen	2.30 (2.07 – 2.53)	1.65 (1.5 - 1.8)
GOR	m^3/m^3	5.0	5.0
Diluent fraction in dilbit	vol%	0.25	0.25
Dilbit API gravity	°API	19[3]	19[3]
Solvent recovery	%	-	89.4[2] (80-95)
Electricity generation	MW	64	45.2
Electricity consumption	MW	64	45.2
Percentage of steam generated with cogeneration	%	40	40
Steam quality at generator outlet	%	100	100
Fraction of NG/PG consumed in drum boiler	%	98 / 2	98 / 2
Fraction of NG/PG consumed in gas turbine	%	100 / 0	100 / 0
Evaporator electricity consumption	kWh/bbl inlet	3.26 (2 – 4)	3.26 (2 – 4)
Turbine type	-	GE 7EA	GE 7EA

Turbine efficiency[4]	-	0.327	0.327

Notes: [1]Source: IOL 2013, 2015, 2018; [2]Calculated based on mass balance data provided in IOL (2015); [3]No public assay was provided by Imperial for SA-SAGD pathway, and Imperial suggested we use a general pipeline requirement and assume an API of 19 for the dilbit assay produced by SA-SAGD technology. In the absence of a public assay with that API gravity, a proxy assay has been employed. The proxy assay selected is a blend of Cold Lake assay and Cold Lake bitumen assay (both available in PRELIM assay inventory) that has an API of 19. [4]Turbine efficiency provided by Imperial.

2.10.9 Sensitivity analysis for upstream stage

We identify two types of uncertainty and variability to explore in a sensitivity analysis: parameter uncertainty and variability (e.g., variability in process energy consumption, range of reported land use change emissions) and model uncertainty and variability (e.g., choice of upstream emission factor, method for crediting pathways for surplus electricity exported to the grid) as defined by Lloyd and Ries (2008). Table 2-14 and Table 2-15 present the parameters explored in the sensitivity analysis for parameter uncertainty/variability and model uncertainty/variability, respectively, for the well-to-refinery boundary. For each parameter, low and high values are presented to represent the range of variability or uncertainty expected for that parameter.

Table 2-14. Sensitivity to parameter uncertainty and variability, well-to-refinery emissions

Parameter	Units	Base case	Low sensitivity	High sensitivity
Land use emissions SAGD (Yeh et al. 2015)	g CO_2eq/MJ bitumen	0.73	0.55	0.89
Land use emissions Imperial Kearl (Yeh et al. 2015)	g CO_2eq/MJ dilbit	0.53	1.25	2.00
Land use emissions CNRL Horizon (Yeh et al. 2015)	g CO_2eq/MJ SCO	0.88	2.09	3.33
Mine face emissions Imperial Kearl (AEMERA 2015)	g CO_2eq/MJ dilbit	0.01	0.05	0.33
Mine face emissions CNRL Horizon (AEMERA 2015)	g CO_2eq/MJ SCO	0.19	0.22	0.37
Tailings emissions Imperial Kearl (Burkus et al. 2014)	g CO_2eq/MJ dilbit	0.17	0.57	1.23

Tailings emissions CNRL Horizon (Burkus et al. 2014)	g CO_2eq/MJ SCO	0.32	1.14	2.31
Fuel consumption and flaring mining	Varies	Production-weighted average of a. 2015-2017 b. 2018	10th percentiles of: a. 2015-2017 b. 2018	90th percentiles of: a. 2015-2017 b. 2018
Evaporator electricity consumption	kWh/bbl inlet	3.26	2.0	4.0
Solvent loss	%	0.11	0.05	0.2
Fraction of steam from cogen	-	0.5 (2017 MEG Annual info sheet)	0.45 (a "no cogen scenario," i.e. fraction of steam from cogen = 0 is presented in the full sensitivity analysis)	0.55 (a "all steam from cogen," i.e. fraction of steam from cogen = 1, is presented in the full sensitivity analysis)
	-	0.4 (Imperial SA-SAGD pathway)	0.3 (0% cogen scenario is presented in sensitivity analysis)	0.5 (100% cogen scenario is presented in sensitivity analysis)
SOR	-	Pathway-specific (see input tables)	SOR varied +/- 10% for in situ pathways	SOR varied +/- 10% for in situ pathways

Table 2-15. Sensitivity to model uncertainty and variability, upstream emissions

Parameter	Units	Base case	Low sensitivity	High sensitivity
Cogeneration credit[1]	t CO_2eq/MWh	0.370 (CCIR credit)	Calculated using same approach as Charpentier et al.	Grid-average emissions intensity (0.696; Alberta Government 2018)
Natural gas/diluent upstream emission factor	g CO_2eq/MJ	6.4 (Senobari 2016)	14.3 (OPGEE default from GREET1_2016 model)	N/A
Diluent recycle scenarios	-	Hybrid case (38% recycled)	All diluent is recovered from dilbit and recycled	All diluent is sourced from PADD2-average crude
Transport means and distance (mining dilbit and SA-SAGD pathways)	-	2,500 km via pipeline	2,500 km via pipeline	2,500 km via rail
Transport means and distance (MEG pathways)	-	Confidential sales data shared by MEG	2,500 km via pipeline	2,500 km via rail

[1] Both high and low sensitivity cases have higher credits for cogeneration compared to the base case, resulting in lower overall emission rates.

2.11 Crude transportation

The GHG emissions from transporting oil sands crudes to refineries were estimated using OPGEE, which estimates emissions from crude transport using data from the GREET model (version GREET1_2016; Wang 2016).

For the base case, for all pathways except the MEG in situ pathways, we assume crude is transported 2,500 km by pipeline (the approximate distance from oil sands facilities to PADD 2 refineries where oil sands crudes are typically refined; Charpentier et al. 2011). In the sensitivity analysis, the impacts of choice of pipeline transport mode (pipeline versus rail) are compared. For MEG in situ pathways, the base case is chosen to reflect sales data that cannot be disclosed. Sensitivity analyses are performed to find transport emissions if 100% of products are shipped 2,500 km via pipeline or rail.

2.12 Refining

Refinery modelling was conducted using PRELIM v1.3 (Abella et al. 2019). This section summarizes the assumptions made for the base case as well as how the impacts of those assumptions are explored in the sensitivity analysis. Crude assays input to PRELIM for this study are presented in Appendix A.2. For Imperial Kearl, CNRL Horizon, and the MEG SAGD/eMSAGP pathways, public assays for those specific projects are employed in this study (obtained from PRELIM's assay inventory). No public assay exists for the SA-SAGD pathway, however Imperial suggested that we use a general pipeline specification for crude transport and use a dilbit with an API gravity of 19. The public dilbit assay with the lowest API gravity is the Cold Lake dilbit assay in the PRELIM inventory (API gravity of 20.4). The Cold Lake dilbit assay is blended with a Cold Lake bitumen assay to generate a dilbit assay with an API gravity of 19. The blended assay is presented in Appendix A.2 (Table A-7).

2.12.1 Modification to PRELIM to generate diluent stream for return to Alberta

PRELIM v1.3 was modified to add a separate refinery product stream (hereafter, pentanes plus) to account for the diluent that is produced by PADD2 refineries and sent back to Alberta for blending with bitumen. The pentanes plus stream is derived from the top cut of the distillation column in the refinery. Typically, this product stream goes to gasoline production. In this case, prior to blending with gasoline, this product stream is separated. The refinery emissions (per bbl of crude refined) are unaffected because no additional processing is required to generate this product stream, however the emissions intensity for refining gasoline is increased slightly as the lowest-emissions product stream is no longer contributing to the gasoline pool.

PRELIM will generate a distinct emissions intensity estimate for producing the pentanes plus stream from each crude that is refined. The emissions for refining this product stream for each oil sands pathway is presented in Table 2-16 below. Each crude has a maximum production rate of pentanes plus (i.e., for every bbl of dilbit refined, there is a limit to the volume of pentanes plus that can be produced in the refinery) depending on the assay's distillation curve. In this study, we have assumed that the maximum amount of this cut goes towards pentanes plus production, however in several cases this is insufficient to generate the required pentanes plus volume to meet the 38% of diluent demand in Alberta that is sourced from PADD2 refineries. A "make-up" volume of diluent is thus required. We assume that this make-up diluent is produced by PADD2 refineries processing a PADD2-average crude blend (from Cooney et al. 2017; see Appendix A for this approach). Refining of this PADD2-average crude blend is modeled in the modified PRELIM to estimate the emissions from producing a pentanes plus stream from this crude blend. The PADD2-average crude blend assay is presented in Table A-8. Upstream emissions for producing this make-up diluent are also obtained from Cooney et al. (2017), who model a PADD2-average crude production and transport emissions using OPGEE (see Appendix A for the rebuild of the PADD2-average emissions). An alternative scenario modeled in the sensitivity analysis is separation of this product stream after the distillation column but prior to isomerization unit. This will decrease refinery emissions slightly on a per bbl crude basis as all of the stream going through the isomerization unit is separated out after distillation, so the isomerization unit is not utilized in the refinery.

Table 2-16. Emissions from producing pentanes plus product stream for diluent return estimated with modified PRELIM

	Base case: C5+ produced in refinery before blending		**Sensitivity: C5+ produced in refinery after distillation unit**		
	Maximum C5+ production (MJ/MJ inlet crude)	Refinery GHG (g CO_2-eq/MJ C5+ produced)	Maximum C5+ production (MJ/MJ inlet crude)	Refinery GHG (g CO_2-eq/MJ C5+ produced)	Reduction in refinery emissions from C5+ separation (kg CO_2eq/bbl crude)
PADD2 average	0.0627	4.90[1]	0.0627	1.97	
Imperial Kearl dilbit	0.0625	5.48	0.0635	2.19	1.19
MEG SAGD/eMSAGP dilbit	0.078	4.88	0.0791	1.68	1.45
Imperial SA-SAGD dilbit	0.0671	4.59	0.0616	2.76	0.76

[1]For diluent sourced from PADD2-average crude, emissions allocated to the diluent are both PADD2-average upstream and crude transport emissions (13.1 g CO_2eq/MJ diluent) and refinery emissions for C5+ production (total upstream, crude transport, and refinery emissions are 18.0 g CO_2eq/MJ diluent).

This PRELIM modification to separate diluent at the refinery has not been validated with actual operating data and there are several uncertain parameters that would affect the emissions associated with producing the pentanes plus stream at a refinery. For example, it is uncertain where this diluent separation occurs in the refinery and whether the maximum pentanes plus production predicted by PRELIM is representative of actual refinery operations. Further, we assume that pentanes plus production is maximized when refineries process dilbit, however in actual operations the pentanes plus stream for export to Canada may be derived from other crudes refined in PADD2, which would affect the emissions intensity associated with the production of this diluent stream. Additional work is needed to validate the approach taken with actual operating data.

2.12.2 Modification to PRELIM to account for variability in refinery product properties

The current version of PRELIM employed in this study (v1.3) allows the properties of refinery products (e.g., carbon content, heating value) to vary depending on the crude processed in the refinery and the configuration of the refinery. Variations in carbon content and heating value of refinery products leads to variability in emissions from the combustion of these products on a per MJ basis. In order to compare pathways across a common functional unit (i.e., refinery products with the same properties) and with the same combustion emissions, PRELIM is modified so that the properties of products produced by different refinery configurations processing different crudes is fixed. As a result, combustion emissions do not vary across pathways for a given refinery product (i.e., gasoline, diesel, jet fuel). In the sensitivity analysis, the sensitivity of results to the version of PRELIM employed (modified or unmodified is explored).

2.12.3 Refinery configuration

PRELIM has the capability to model 10 categories of refinery (hydroskimming, three medium conversion refineries, and six deep conversion refineries), see Abella et al. (2019) for more on how PRELIM models refinery configurations. For the base case, we model dilbit refining in a deep conversion FCC coking refinery and SCO in a medium conversion FCC refinery. Based on communication with the company experts these are the most likely refinery configurations that the respective crudes would be processed in.

2.12.4 Allocation to refinery products

For the base case upstream, crude transport, and refinery emissions are allocated to four main products only: gasoline, diesel, jet fuel, and a pentanes plus stream to represent the diluent that is produced at PADD2 refineries and exported to Canada.

2.12.5 Basis for allocation to refinery products

Upstream emissions are allocated to refinery products based on the energy content of the final products. Refinery emissions are allocated to products on a process-unit level basis, based on the hydrogen content of the products.

2.12.6 Sensitivity analysis for refining stage

Table 11 shows the inputs and assumptions made in modelling refinery emissions in PRELIM that are explored in the sensitivity analysis.

Table 2-17. Sensitivity analysis scenarios for refinery modelling

Parameter	Base case scenario	Low sensitivity	High sensitivity
Refinery configuration	SCO: medium conversion Dilbit: deep conversion FCC	Hydroskimming (dilbit and SCO)	SCO: deep conversion coking Dilbit: deep conversion hydrocracking
Product slate	LPG and petrochemical feedstock production is off	LPG and petrochemical feedstock production is off	LPG and petrochemical feedstock production is on
Allocation to multiple refinery products	Emissions allocated to gasoline, diesel, jet fuel, and pentanes plus	Emissions allocated to all refinery products (incl. LPG and petrochemicals)	Emissions allocated to gasoline, diesel, jet fuel, and pentanes plus
Basis for allocation of refinery emissions	Process level allocation on an H_2 basis	Process level allocation on an energy content (HHV) basis	Process level allocation on an energy content (HHV) basis
Diluent recycle scenario	Hybrid case (38% diluent recycled)	All recycled diluent sourced from dilbit	50% diluent sourced from PADD2
Version of PRELIM	1.3 (modified to fix carbon content of refinery products)	1.3 (unmodified; carbon content of products varies)	1.3 (unmodified; carbon content of products varies)
Separation of C5+ stream at refinery	Before blending (after isomerization unit)	After distillation column	N/A

2.13 Refined products transportation

For the base case, emissions for transport of refined products (gasoline, diesel, jet fuel) are based on the approach taken in Sleep et al. (2019), who calculate emissions for transport of refined products based on the transport of refined products across the U.S. using 2009 data. The sensitivity analysis shows an alternative scenario where refined products transportation emissions are obtained from the OCI (Gordon et al. 2015), who use the (OPEM v1.1) model to estimate emissions from transporting these products via pipeline and then tanker truck. The OCI GHG emissions estimate for refined products transport 2,414 km via pipeline (the distance from Houston to the New York-New Jersey region) and then 380 km via tanker truck (the additional distance to reach the Boston region; see Table 2-18). The sensitivity analysis also shows the impact of transport distance on GHG emissions from refined products transport if the pipeline transport distance is reduced to 300 km to reflect the proximity of PADD 2 refineries (where most oil sands crudes are refined) to markets for refinery products.

Table 2-18. Base case emission factors and transport distances for transporting refinery products from refinery to market

Transport mode	Base case: Sleep et al. transportation emission factors (g CO_2eq/kg.km)[1]	Base case: Sleep et al. transport distance (km)	Reference scenario: OCI transportation emission factors (g CO_2e/kg.km)	Reference scenario: OCI transport distance (km)
Truck		0	0.1043	380
Ocean tanker	N/A (not provided)	0	0.0047	0
Barge	N/A (not provided)	0	0.0415	0
Pipeline		480	0.0169	2,414
Rail		0	0.0295	0

[1]Combustion emissions factors from Sleep et al. are presented in kg CO_2eq/ton-mile, converted to kg CO_2eq/kg.km for comparison to OCI values.

2.14 Refined products combustion

For the base case, emissions from the combustion of a selection of refinery products (gasoline, diesel, and jet fuel) are calculated based on the carbon content of the product (as predicted by PRELIM, assuming fixed carbon contents for individual fuels, e.g., gasoline, across refinery configurations and crude types, see the description of how PRELIM was modified for this study in Section 2.12), employing the following equation (from Canada's Greenhouse Gas Quantification Requirements, Greenhouse Gas Reporting Program; GHGRP 2018):

$$\boldsymbol{EM_{ref,prod}} \left(\frac{\boldsymbol{kgCO2}}{\boldsymbol{bbl\ fuel}}\right) = \boldsymbol{CC}\ (\boldsymbol{wt}\%) \times \boldsymbol{Fuel\ mass} \times \boldsymbol{3.66} \times \boldsymbol{fuel\ density}\ \left(\frac{\boldsymbol{kg}}{\boldsymbol{bbl}}\right)$$

Where EM is the combustion emission factor of the refinery product, in kg CO_2 per bbl of fuel/product; CC is the carbon content (based on a weight percentage) of the fuel; Fuel mass is the mass of the fuel; and fuel density is the density of the fuel, in kg/bbl of fuel. For other refinery products (fuel oil, petroleum coke, and residual fuels), as carbon content is not tracked in PRELIM, combustion emission factors are obtained from the OCI (Gordon et al. 2015). The combustion emissions based on this approach will vary slightly across crude assays and refinery configurations. Example base case combustion emission factors are presented in Table 2-19.

For the sensitivity analysis, two alternative scenarios for modelling refined products combustion are considered: 1) a case where combustion emissions for refinery products are obtained from the NETL petroleum baseline (as presented in Cooney et al. 2017); and 2) a case where combustion emissions for refinery products are obtained from the Oil Climate Index report (Gordon et al. 2015). Emissions for the combustion of refinery products from the sources described above are presented in Table 2-19. We also explore the effect of coke combustion in the sensitivity analysis, which is varied from 80-100% (from 99%, selected for the base case).

Table 2-19. Comparison of combustion emissions from OCI and NETL Petroleum Baseline

Refinery product	Reference scenario: NETL combustion emission factor (g CO_2eq/MJ product)	Reference scenario: OCI combustion emission factor (g CO_2eq/MJ product)
Gasoline	72.7	74.5
Jet Fuel	73.7	74.6
Diesel	72.7	75.0
Fuel Oil	70.4	71.4
Petroleum Coke	97.3	110.5
Residual Fuels	71.5	72.8

3 Results

GHG emissions are estimated and presented below for chosen boundaries and functional units. Additional base case results for different boundaries and functional units are presented in Appendix E along with additional sensitivity analysis results.

For existing pathways, results are presented for two time periods. The first is an estimate developed using 2015-2017 production-weighted average monthly operating data (to represent historic operations). These (2015-2017) results are compared for mining pathways to facility-wide direct emissions reported under Environment and Climate Change Canada's GHGRP (GHGRP 2018), which are available from 2004-2017. The MEG SAGD/eMSAGP pathway is compared to publicly reported data for the 2018 operating year, where the most detailed comparison to publicly reported emissions could be made. A second GHG emissions intensity estimate is made using 2018 operating data, the most recent available data, to represent steady state operations. For each existing technology pathway, 2015-2017 (historic) and 2018 (steady state) GHG intensity estimates are compared to show how GHG intensities have changed at these projects as efficiency improvements are made.

3.1 Upstream GHG emissions for current oil sands pathways with comparison to publicly reported emissions

3.1.1 Imperial Kearl pathway

Imperial Kearl pathway upstream GHG emissions intensity estimates are shown in Figure 3-1 below. Results are reported in kg CO_2eq/bbl dilbit leaving the facility. Three types of results are shown in the figure:

1. Two OPGEE best estimate results (left side of figure), which include all emissions sources within the OPGEE boundary. These include direct (combustion) emissions from fuels consumed and on-site fugitive emissions (mine face and tailings ponds emissions),

as well as upstream (off-site) emissions from producing and supplying the fuels that are consumed on-site, emissions from importing electricity from the grid, and land use emissions from, for example, habitat and soil carbon loss. Two sets of OPGEE best estimate results are reported for the Imperial Kearl pathway: one based on 2015-2017 operating data and another based on 2018 operating data (representing steady state operations, most recent data available at the time of this report).

2. An estimate of direct emissions modeled using OPGEE (third and fifth bar from the left side of the figure). OPGEE boundaries are adjusted to align with those of the SGER reporting requirements and include direct (combustion) emissions from fuels consumed on-site and on-site fugitive emissions emitted in that year of operation (mine face and tailings ponds emissions). Two sets of results are reported for the Imperial Kearl pathway: one based on 2015-2017 operating data and another based on 2018 operating data (representing steady state operations, most recent data available at the time of this report based on monthly energy consumption data reported in the AER ST39 dataset).
3. The production-weighted average GHG intensity of the Imperial Kearl pathway based on public GHG emissions reported for the Kearl project under the SGER (middle bar in the figure). Results are presented for a 2015-2017 case and a 2018 case (fourth and sixth bars from the left side of the figure, respectively).

When publicly reported emissions estimates are used to evaluate OPGEE and boundaries are aligned between those employed in generating publicly reported emissions estimates and OPGEE, OPGEE predicts the emissions for the Imperial Kearl pathway within 0.7 kg CO_2eq/bbl dilbit (or within 2.2%). Note the boundaries associated with these estimates do not include indirect emissions; both direct and indirect emissions are included in the OPGEE best estimate results which are discussed below.

OPGEE best estimate upstream emissions from the Imperial Kearl pathway are 58.2 and 54.7 kg CO_2eq/bbl dilbit leaving the facility for the 2015-2017 and 2018 timeframes, respectively. Across the 2015-2017 and 2018 timeframes, upstream emissions for this pathway decreased by 3.5 kg CO_2eq/bbl dilbit, a reduction in upstream emissions of 6.0%. Note that the change in emissions intensity across the two timeframes may not be predictive of future emissions intensity changes as projects are continually adapting in their operating decisions and technologies employed. The contribution of individual parameters to uncertainty and variability are presented in Figure 3-12.

For this pathway, the biggest driver of absolute emissions for both the 2015-2017 and 2018 timeframes is direct emissions from natural gas combustion. The biggest source of indirect emissions is the upstream emissions from diluent supply. The emissions associated with diluent sourcing is highly uncertain due to both uncertainty in upstream emissions for locally supplied diluent and uncertainty in how diluent sourced from PADD2 refineries is produced at the refinery. The effects of this uncertainty is explored in the sensitivity analysis (see Figure 3-12).

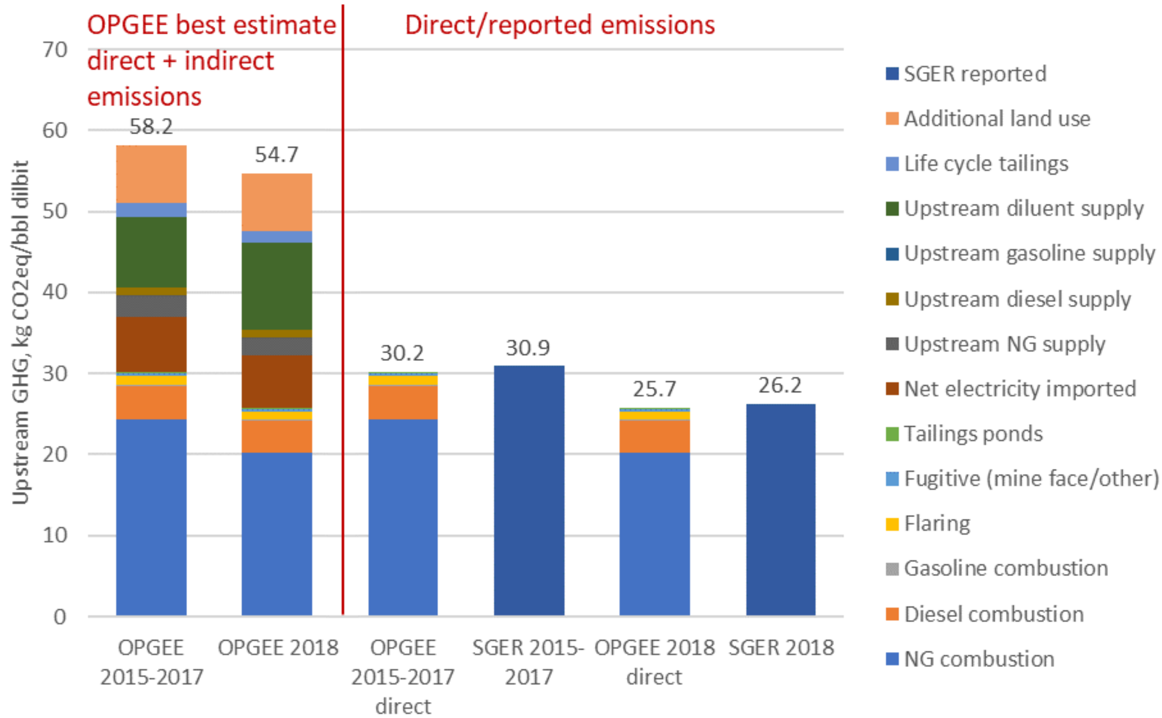


Figure 3-1. Upstream GHG emissions for Imperial Kearl pathway with comparison to publicly reported emissions for Kearl project.

Stacked bars show the breakdown of GHG emissions by source for Kearl pathway base case results. The two bars on the left side of the figure represent direct and indirect emissions for dilbit production, including all emissions sources within the OPGEE boundary. 2018 is expected to be the best representation of steady state operations. 2015-2017 GHG emissions intensities may have been affected by forest fires in the Fort McMurray area. The four bars on the right side represent emissions if life cycle boundaries are aligned with the SGER/CCIR (only includes emissions within the facility boundary). Note that SGER/CCIR reports emissions on an annual basis for the entire facility; these are converted to a per bbl crude basis using crude production data reported to the AER. The impacts of uncertainty and variability on results for Imperial's Kearl pathway are presented in detailed sensitivity analysis, see Figure 3-12.

3.1.2 CNRL Horizon pathway

CNRL Horizon pathway upstream (bitumen production and upgrading) GHG intensity estimates are shown in Figure 3-2 below. Results are reported in kg CO_2eq/bbl SCO leaving the facility. Three types of results are shown in the figure:

1. Two OPGEE best estimate results (left side of figure), which include all upstream emissions sources within the OPGEE boundary. These include direct (combustion) emissions from fuels consumed and on-site fugitive emissions (mine face and tailings ponds emissions), as well as upstream (indirect) emissions from producing and supplying the fuels that are consumed on-site, emissions from importing electricity from the grid, and land use emissions from, for example, habitat and soil carbon loss. Two sets of OPGEE best estimate results are reported for the CNRL Horizon pathway: one based on 2015-2017 operating data and another based on 2018 operating data

(representing steady state operations, most recent data available at the time of this report).

2. An estimate of direct emissions modeled using OPGEE (third and fifth bar from the left side of the figure). OPGEE boundaries are adjusted to align with those of the SGER reporting and include direct (combustion) emissions from fuels consumed and on-site fugitive emissions emitted in that year of operation (mine face and tailings ponds emissions). Two sets of results are reported for the CNRL Horizon pathway: one based on 2015-2017 operating data and another based on 2018 operating data (representing steady state operations, most recent data available at the time of this report).
3. The production-weighted average GHG intensity of the CNRL Horizon pathway based on public GHG emissions reported for the Horizon project under the SGER (fourth and sixth bars from the left hand side of the figure in Figure 3.2). Results are presented for a 2015-2017 case and a 2018 case.

When OPGEE boundaries are aligned with those employed in generating publicly reported emissions estimates, OPGEE predicts the emissions for this pathway within 1.1 kg CO_2eq/bbl SCO (2015-2017 timeframe) and 3.1 kg CO_2eq/bbl SCO (2018 timeframe), or within approximately 1-4%. Note the boundaries associated with these estimates do not include indirect emissions; both direct and indirect emissions are included in the OPGEE best estimate results which are discussed below.

OPGEE best estimate upstream emissions from the CNRL Horizon pathway are 107.9 and 93.3 kg CO_2eq/bbl SCO leaving the facility for the 2015-2017 and 2018 timeframes, respectively. Across the 2015-2017 and 2018 timeframes, upstream emissions for this pathway decreased by 14.6 kg CO_2eq/bbl SCO, a reduction in upstream emissions of 13.5%. Note that the change in emissions intensity across the two timeframes may not be predictive of future emissions intensity changes as projects are continually adapting in their operating decisions and technologies employed. The contribution of individual parameters to variability and uncertainty are presented in Figure 3-13.

For this pathway, the biggest driver of absolute emissions for both the 2015-2017 and 2018 timeframes is direct emissions from natural gas and process gas combustion. Emissions for mining and upgrading are 45.3 and 62.6 kg CO_2eq/bbl SCO, respectively for the 2015-2017 timeframe are 38.7 and 54.6 kg CO_2eq/bbl SCO, respectively for the 2018 timeframe. As the upgrader is located on the mine site, waste heat from the upgrader is employed for bitumen extraction, resulting in substantial reductions in emissions intensity for mining in this pathway.

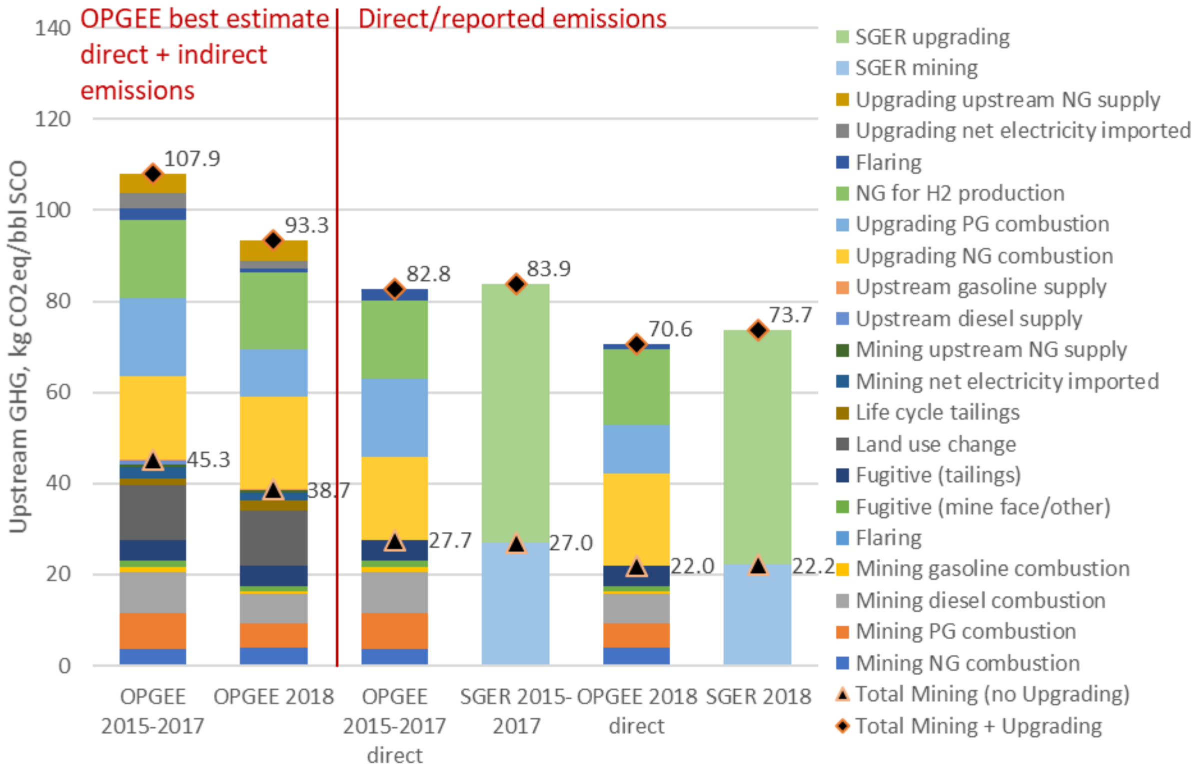


Figure 3-2. Upstream GHG emissions for CNRL Horizon pathway with comparison to publicly reported emissions for Horizon project.

Stacked bars show breakdown of GHG emissions by source for Horizon pathway base case results. The two bars on the left side of the figure represent direct and indirect emissions for SCO production, including all emissions sources within the OPGEE boundary. The three bars on the right side represent emissions if boundaries are aligned with the SGER (only includes emissions within the facility boundary). 2018 is expected to be the best representation of steady state operations. 2015-2017 GHG emissions intensities may have been affected by forest fires in the Fort McMurray area. Note that SGER/CCIR reports emissions on an annual basis for the entire facility; these are converted to a per bbl crude basis using crude production data reported to the AER. The impacts of uncertainty and variability on results for CNRL's Horizon pathway are presented in detailed sensitivity analysis, see Figure 3-13.

3.1.3 MEG SAGD pathway

The OPGEE SAGD results are presented in Figure 3-3 for four scenarios for crediting MEG for surplus electricity generation. The positive components of the four stacked bars are unchanged across the bars. The negative components show four ways of crediting exported electricity. As CLRP uses less than 30% of the electricity generated onsite, MEG exports a significant amount of electricity to the Alberta grid and OPGEE recognizes this as a credit in the model. Other projects in this study are not net exporters of electricity so these scenarios apply only to MEG.

While OPGEE evaluation with publicly reported regulatory emissions data was undertaken for other existing technology pathways (i.e., Imperial Kearl and CNRL Horizon), for the MEG CLRP

OPGEE evaluation is undertaken for the 2018 operating year by comparing CLRP-reported emissions data to the MEG eMSAGP (emerging technology) pathway. By the end of 2018, more than half of the wells at CLRP had been converted to eMSAGP. We therefore consider the 2018 CLRP reported emissions data to be more representative of an eMSAGP project than a SAGD project, so conduct the model evaluation in that Section (Section 3.2.1).

With the credit for surplus electricity exported to the grid ranging from 0.25 to 0.696 ton/MWh, the resulting emission intensity can range from 56.2 to 69.1 kg CO_2e/bbl dilbit. The base case assumes a credit of 0.370 ton/MWh for surplus electricity exported to the grid, aligning with the current (as of 2019) CCIR regulation in Alberta. Another case (the 3rd bar from the left) assumes a credit of 0.418 ton/MWh for electricity, which is the emission intensity of "an 80% efficient boiler and a natural gas combined cycle electricity plant" recognized by the SGER (Alberta Climate Change Office 2018). The second scenario uses a credit of 0.250 ton/MWh, which accounts for the facility-specific emissions for generating the electricity. The cogen at CLRP is modeled with 30% electricity generation efficiency, 3% shell loss, and 67% heat transferred into steam. We attribute the 33% (from electricity generation and shell loss) of fuel fed into turbine as the fuel used for electricity generation. The resulting carbon intensity for electricity generation is 0.250 ton/MWh, assuming an upstream natural gas carbon intensity of 6.4 g/MJ and combustion of a natural gas mixture that is 93% imported natural gas and 7% produced gas. This method is referred to as the "attribution method" in Table 2-15. The fourth credit of 0.696 ton/MWh is the average of Alberta grid's operating margin for the past five years (Alberta Government 2018).

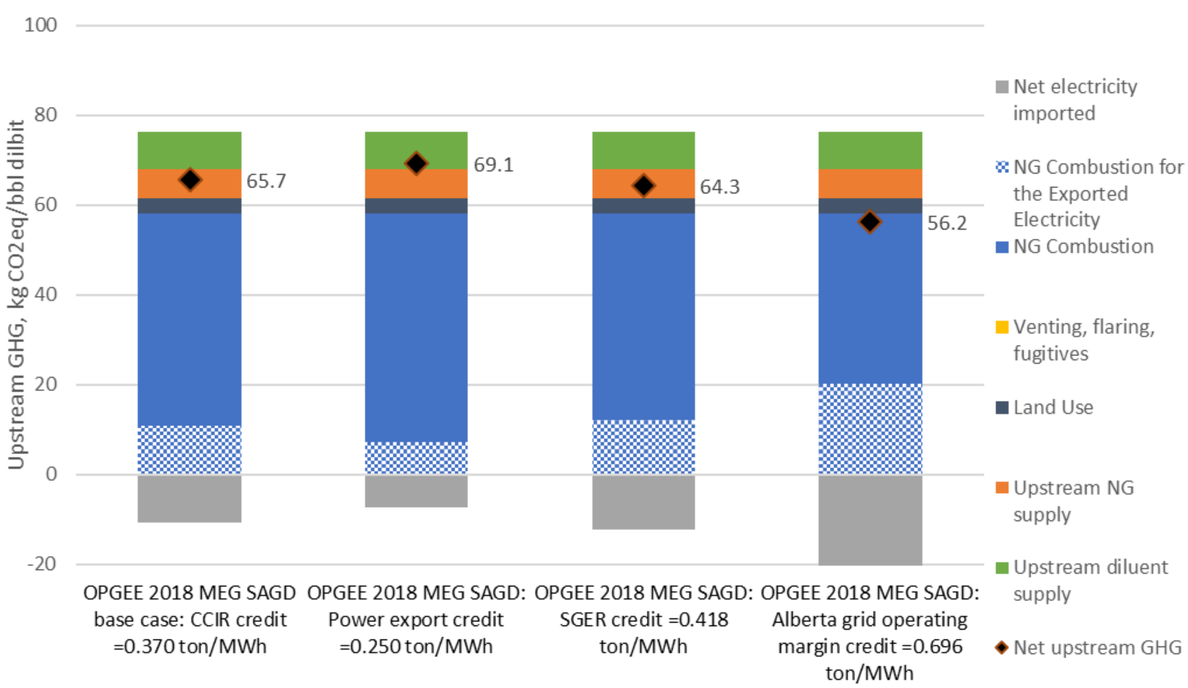


Figure 3-3. Upstream GHG emissions for MEG SAGD pathway for different electricity export emissions credit scenarios.

Stacked bars show breakdown of GHG emissions by source for MEG SAGD pathway base case results for four electricity export credit scenarios. The impacts of uncertainty and variability on results for MEG's SAGD pathway are presented in detailed sensitivity analysis, see Figure 3-14.

3.2 Upstream GHG emissions for emerging oil sands pathways with comparison to existing SAGD pathways

3.2.1 MEG eMSAGP pathway

eMSAGP is a new technology which involves co-injection of natural gas with steam. Typically, eMSAGP is deployed after achieving 30% oil recovery via SAGD. Under MEG's plan of production expansion with new SAGD development and eMSAGP deployment, SAGD and eMSAGP wells are expected to co-exist in CLRP. As of quarter one of 2019, MEG has converted over half of its existing wells to eMSAGP wells and hence the current operating data is taken as input for eMSAGP case. The eMSAGP case modeled with OPGEE is based on operating data.

To better estimate the emission reduction impacts of eMSAGP, 2018 operational data (production rate, diluent fraction, etc.) are assumed for modeling MEG's SAGD base case except for SOR and GOR. Although MEG initiated its first eMSAGP pilot in December 2011, the impact of eMSAGP was limited prior to the start of 2014. In 2013, CLRP fieldwide SOR was 2.57 from nearly purely SAGD operations (MEG ISPP 2014). Thus, a slightly greater SOR of 2.6 (to remove the limited impact of 2013 eMSAGP deployment) is assumed for MEG to continue SAGD practice into 2018. The SOR of 2.6 is a theoretical value for 2018 CLRP SAGD operations assuming a similar rate of new well development in 2013 and 2018 and unchanged reservoir characteristics across years of oil recovery. A GOR of 5, which is one of the reported heavy oil properties in MEG's CLRP Phase 3 application, instead of the operational GOR is assumed for SAGD base case to remove the impact of natural gas injection and recycling from eMSAGP.

Figure 3-4 shows that if MEG were to continue SAGD operations into 2018, its fieldwide upstream GHG emissions intensity are estimated to be 65.7 kg CO_2eq/bbl dilbit. With the deployment of eMSAGP, the 2018 GHG emissions intensity is estimated to decrease to 55.7 kg CO_2eq/bbl dilbit, which is a 15% reduction from SAGD base case. OPGEE's best estimates of indirect eMSAGP emissions excluding the impacts from land use, upstream natural gas and diluent supply, is 37.9 kgCO_2eq/bbl dilbit. Compared to MEG's reported 2018 emission intensity of 39.9 kgCO_2eq/bbl dilbit (converted from 51 kgCO_2eq/bbl bitumen reported online with heating values in Table 2.1 and volumetric fraction of diluent in final product of 27%), the difference is less than 2%. Both the direct emissions intensity estimated by OPGEE and the MEG reported emissions intensity assume an electricity export crediting factor of 0.418 ton/MWh (SGER credit).

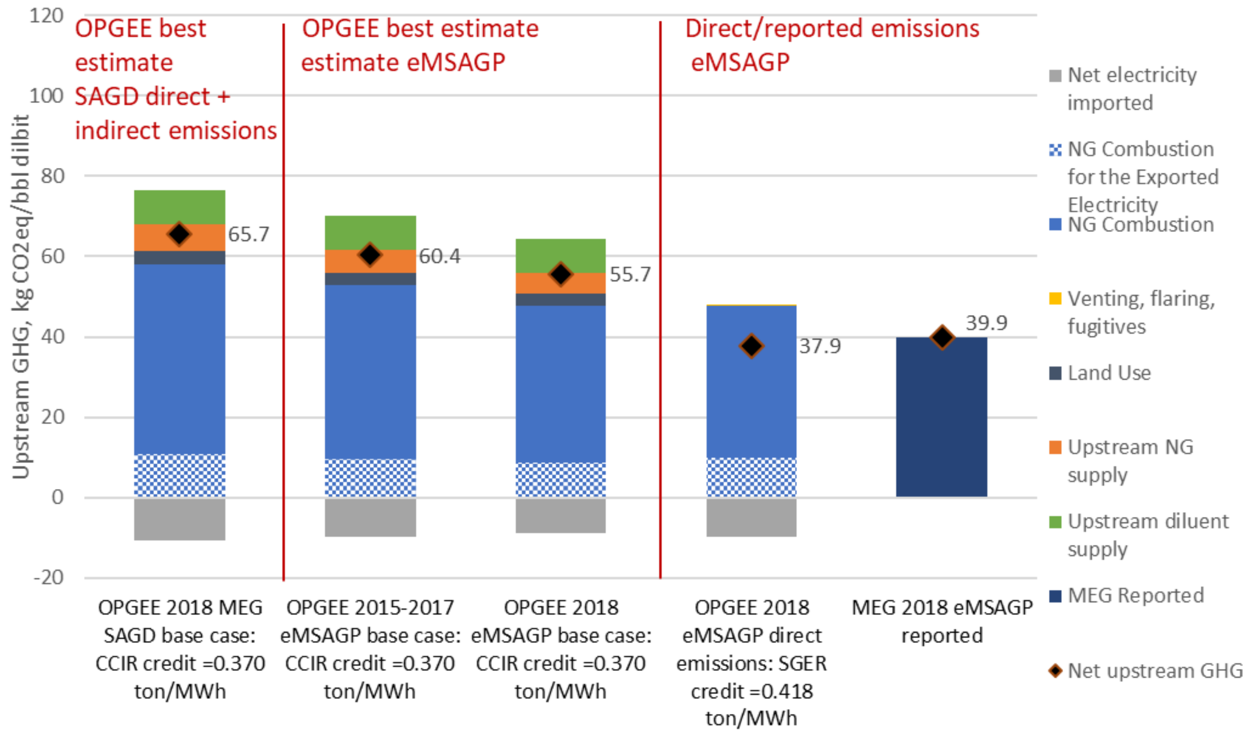


Figure 3-4. Upstream GHG emissions for MEG eMSAGP pathway.
Stacked bars show breakdown of GHG emissions by source for MEG eMSAGP pathway base case results. The three bars on the left side of the figure represent life cycle emissions for dilbit production, including all emissions sources within the OPGEE boundary. The two bars on the right side present dilbit production emissions if life cycle boundaries are aligned with the SGER (only includes emissions within the facility boundary). The impacts of uncertainty and variability on results for MEG's eMSAGP pathway are presented in detailed sensitivity analysis, see Figure 3-15.

3.2.2 Imperial SA-SAGD pathway

Figure 3-5 shows upstream GHG emissions for Imperial SA-SAGD pathway based on the assumptions that were presented in Methods Section 2.10. A reference SAGD pathway is presented as well, to evaluate emissions reduction that can be obtained by implementing SA-SAGD emerging technology as an alternative to conventional SAGD technology.

Stacked bars show breakdown of GHG emissions by source for SA-SAGD and SAGD pathways base case results based on simulated data from the Aspen SA-SAGD regulatory applications. OPGEE estimates for SA-SAGD and SAGD pathways emissions intensity are 48.3 and 61.3 kg CO_2eq/bbl dilbit, respectively. The emissions estimate results show an approximately 21% reduction in upstream GHG emissions when SA-SAGD is deployed compared to SAGD at the same reservoir.

For these pathways, the biggest driver of absolute emissions is direct emissions from natural gas and process gas combustion. Natural gas combustion emissions for SA-SAGD pathway are reduced by 28% compared to the reference SAGD pathway as a result of reduced SOR value for SA-SAGD technology. Diluent upstream emissions are slightly higher for SA-SAGD pathway as part of the injected diluent (solvent) is lost to the reservoir in this pathway (approximately 10% based on regulatory application data).

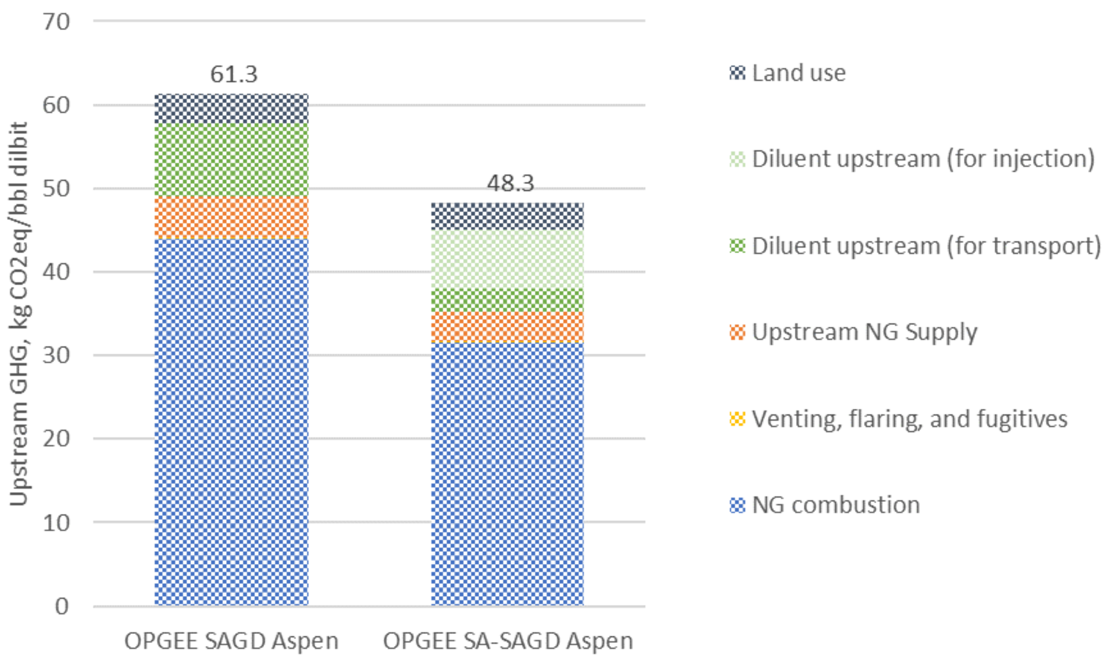


Figure 3-5. Upstream GHG emissions for Imperial SA-SAGD pathway.
Stacked bars show breakdown of GHG emissions by source for SA-SAGD and reference SAGD pathway base case results based on simulated data from the Aspen SA-SAGD regulatory applications. The impacts of uncertainty and variability on results for Imperial's SA-SAGD pathway are presented in detailed sensitivity analysis, see Figure 3-16.

OPGEE estimates for NG combustion emissions and electricity generation are compared to simulation results provided in the Aspen project application (IOL, 2018) and presented in Table 3-1 below. Total NG and PG combustion emissions, electricity generation and direct emissions intensity estimated by OPGEE is within 1% of the simulation results provided by Imperial (IOL 2018).

Table 3-1. Comparison of OPGEE fuel consumption estimates with SA-SAGD application

Parameter	Table 12-2 & Appendix B.15 [3]	OPGEE	% error
Total natural gas combusted (GJ HHV/d)	129,900	131,475	1.2%
Total CO_2eq from NG combustion (kt CO_2eq/yr)	2,450	2,449	-0.1%
Total produced gas combusted (GJ HHV/d)	2,100	2,132	1.5%
Total CO_2eq from PG combustion (kt CO_2eq/yr)	21	40	89.6%
Total NG + PG combusted (GJ HHV/d)	132,000	133,607	1.2%

Total CO_2eq from NG + PG combustion (kt CO_2eq/yr)	2,471	2,488	0.7%
Electricity generation (MW)	90.4	90.9	0.5%
Total direct emissions intensity (t CO_2eq/bbl bitumen)	0.0419	0.0422	0.7%

3.2.3 Comparison of upstream GHG emissions intensities across current and emerging oil sands pathways

Figure 3-6 shows OPGEE's best estimate of upstream GHG emissions intensities across the five oil sands pathways modeled in this study. Results are generated from the 2018 base case results, except for the Imperial SA-SAGD pathway which is modeled using simulated data from the Aspen SA-SAGD regulatory application as the project had not commenced operations at the time of this report. Results are presented in kg CO_2eq/bbl crude (dilbit in the case of the Kearl and in situ pathways; SCO for the Horizon pathway). Net upstream GHG emissions intensities are noted by a black diamond in the figure. While study boundaries and data sources were aligned across pathways where possible, due to differences in data availability each pathway was modeled with some differences in data sources and assumptions. Differences in data sources and assumptions across pathways for the upstream stage are presented in Section 2.10. Note that each pathway produces a crude with unique properties that will have distinct downstream emissions, particularly the CNRL Horizon pathway which produces SCO while other pathways produce dilbit.

New emerging in situ technologies are expected to be deployed may achieve additional reductions in upstream GHG intensities. A current project by COSIA has shown reductions in land footprints at in situ sites over the 2012-2017 period of 6.9% which may lead to similar reductions in life cycle land use emissions for in situ projects (COSIA 2019). Better data may soon be available (e.g., improved data on land use and fugitive emissions through continuous monitoring at oil sands sites) that may reduce both the absolute GHG intensity as well as the uncertainty associated with the emissions estimates for those parameters. As such, the GHG emissions intensity estimates and near-term emissions intensity reductions presented in this study are not intended to be representative of future emissions intensity reductions, but rather show how these technologies perform (or are expected to perform in the case of SA-SAGD) and for existing technologies, how that performance has changed over the 2015-2018 operating period.

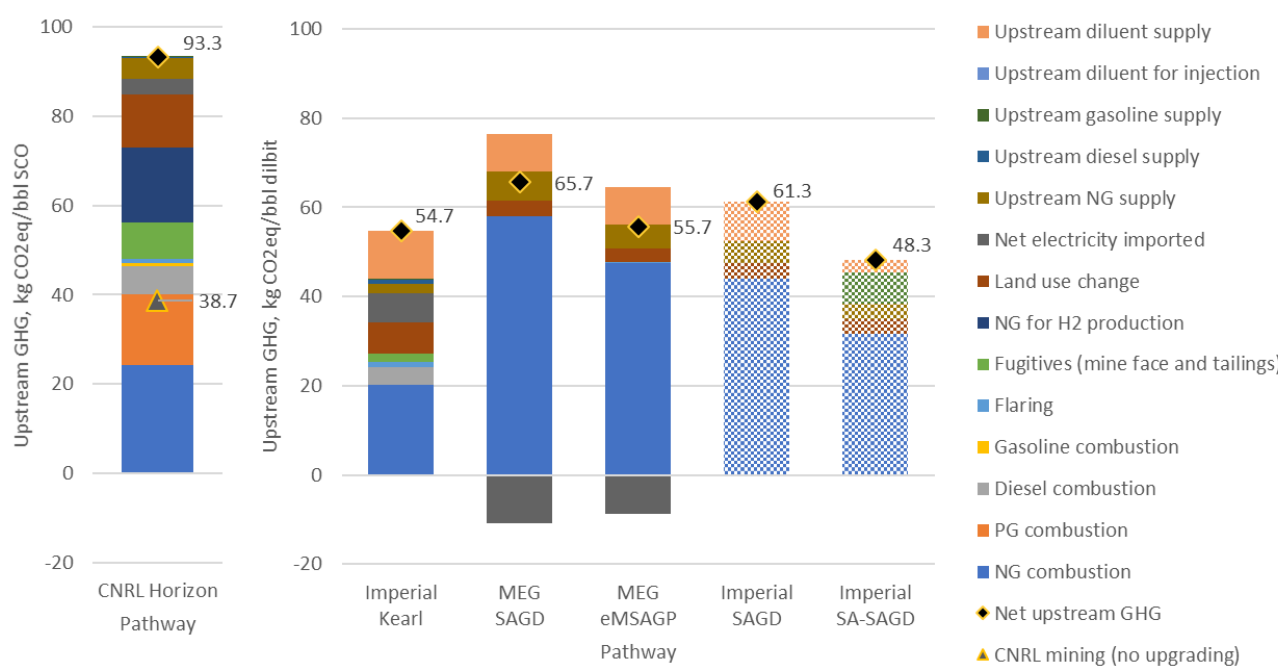


Figure 3-6. Upstream GHG emissions for current and emerging oil sands pathways per bbl of crude (dilbit: Imperial/MEG pathways; SCO: CNRL pathway).
Stacked bars show breakdown of GHG emissions by source for 2018 steady state oil sands pathway base case results and a theoretical Imperial SAGD and SA-SAGD pathway based on regulatory application data. Diamonds show net upstream GHG emissions per bbl of dilbit or SCO leaving facility. While Imperial Kearl and CNRL Horizon pathways are net importers of electricity and the Imperial SA-SAGD pathway is anticipated to have a cogen system that meets its demand for electricity, MEG SAGD and eMSAGP pathways are net exporters of electricity. A credit is given to those pathways for their net electricity exported to the grid. While uncertainty and variability are not shown in the figure, several sources of uncertainty and variability are present in these base case emissions intensity estimates. The impact of sources of variability and uncertainty on WTR and WTW GHG emissions intensity results are explored for each oil sands pathway in the sensitivity analysis sections.

3.3 Well-to-refinery GHG emissions for current and emerging oil sands pathways

Sections 3.3.1 to 3.3.5 present WTR results for each oil sands pathway included in this study. Results are presented in g CO_2eq/MJ crude (dilbit or SCO), the default functional unit employed in OPGEE, to facilitate comparisons with other OPGEE results.

3.3.1 Imperial Kearl pathway

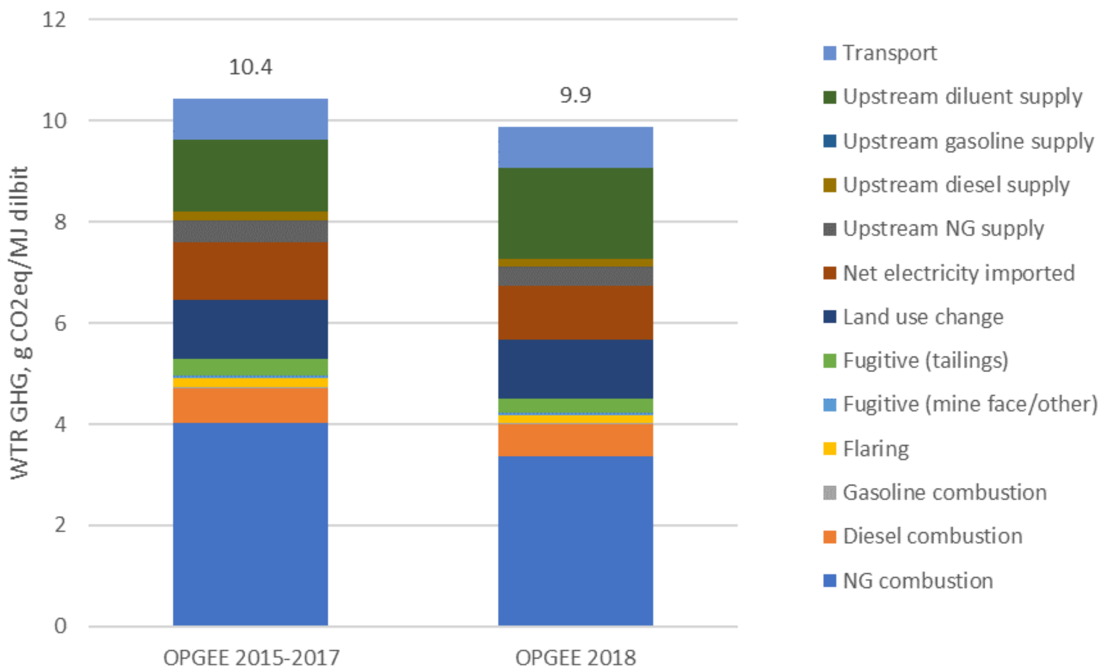


Figure 3-7. Well-to-refinery GHG emissions for Imperial Kearl pathway.
Stacked bars show breakdown of GHG emissions by source for Kearl pathway base case results. The impacts of uncertainty and variability on results are presented in detailed sensitivity analysis, see Figure 3-12).

3.3.2 CNRL Horizon pathway

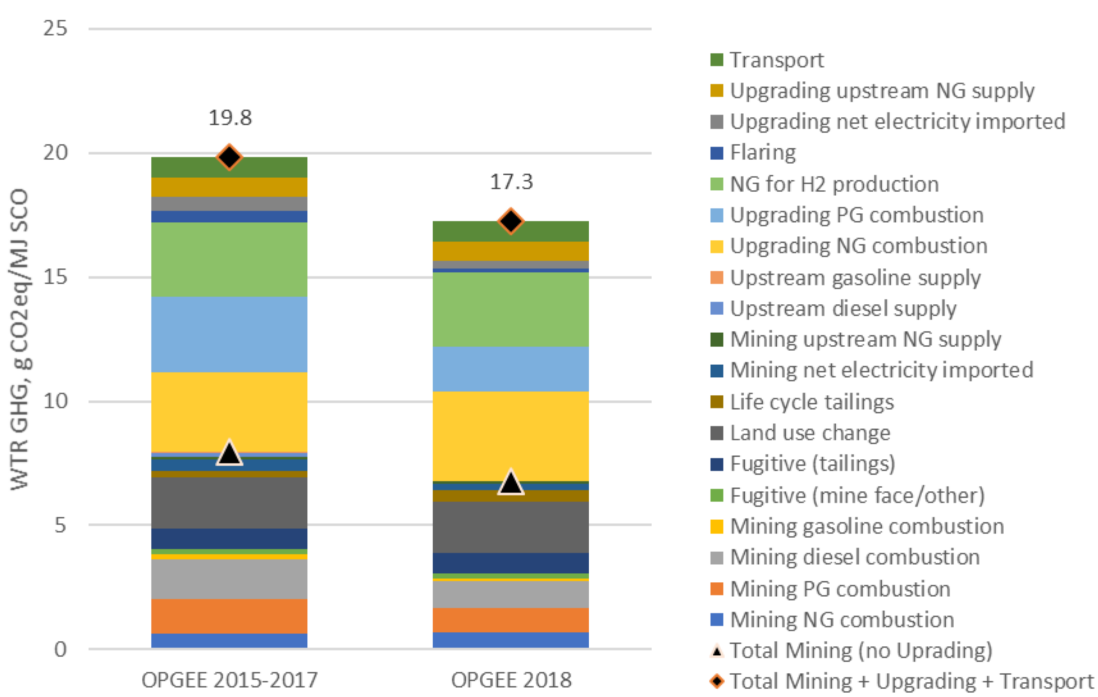


Figure 3-8. Well-to-refinery GHG emissions for CNRL Horizon pathway.

Stacked bars show breakdown of GHG emissions by source for Horizon pathway base case results. The impacts of uncertainty and variability on results are presented in detailed sensitivity analysis, see Figure 3-13).

3.3.3 MEG SAGD pathway

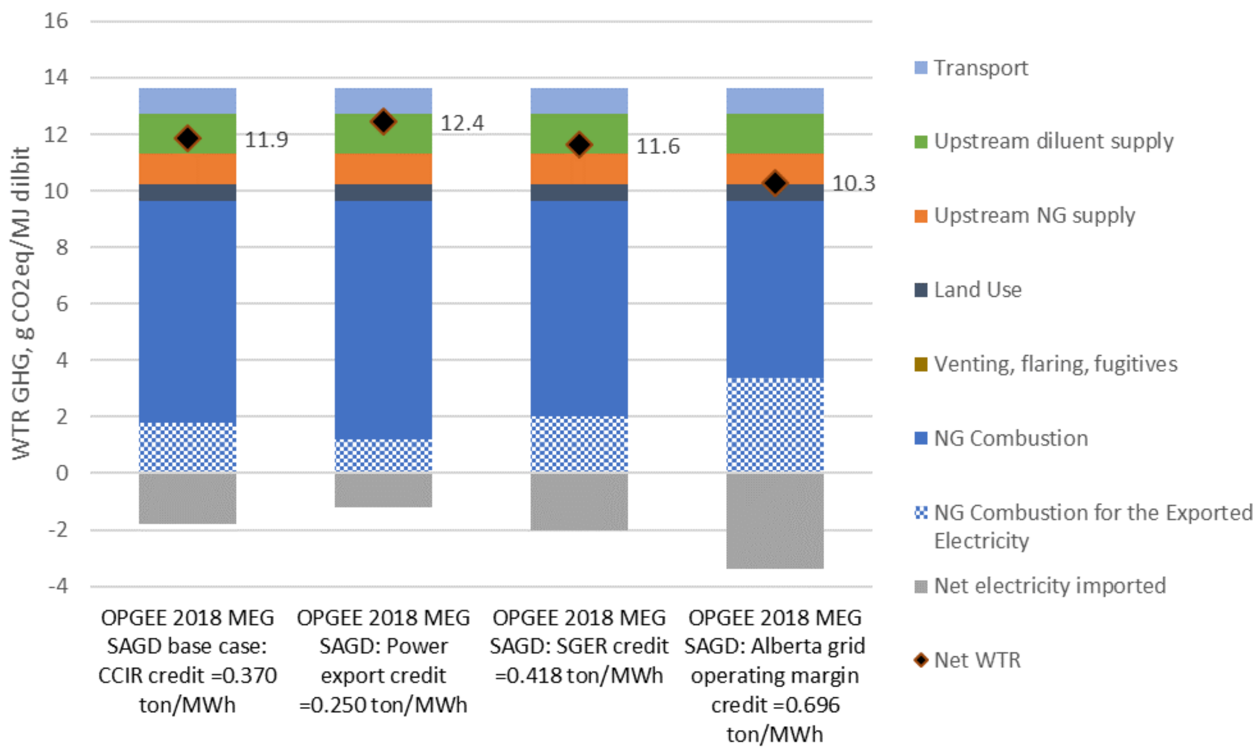


Figure 3-9. Well-to-refinery GHG emissions for MEG eMSAGP pathway.
Stacked bars show breakdown of GHG emissions by source for MEG eMSAGP pathway base case results. The impacts of uncertainty and variability on results are presented in detailed sensitivity analysis, see Figure 3-15).

3.3.4 MEG eMSAGP pathway

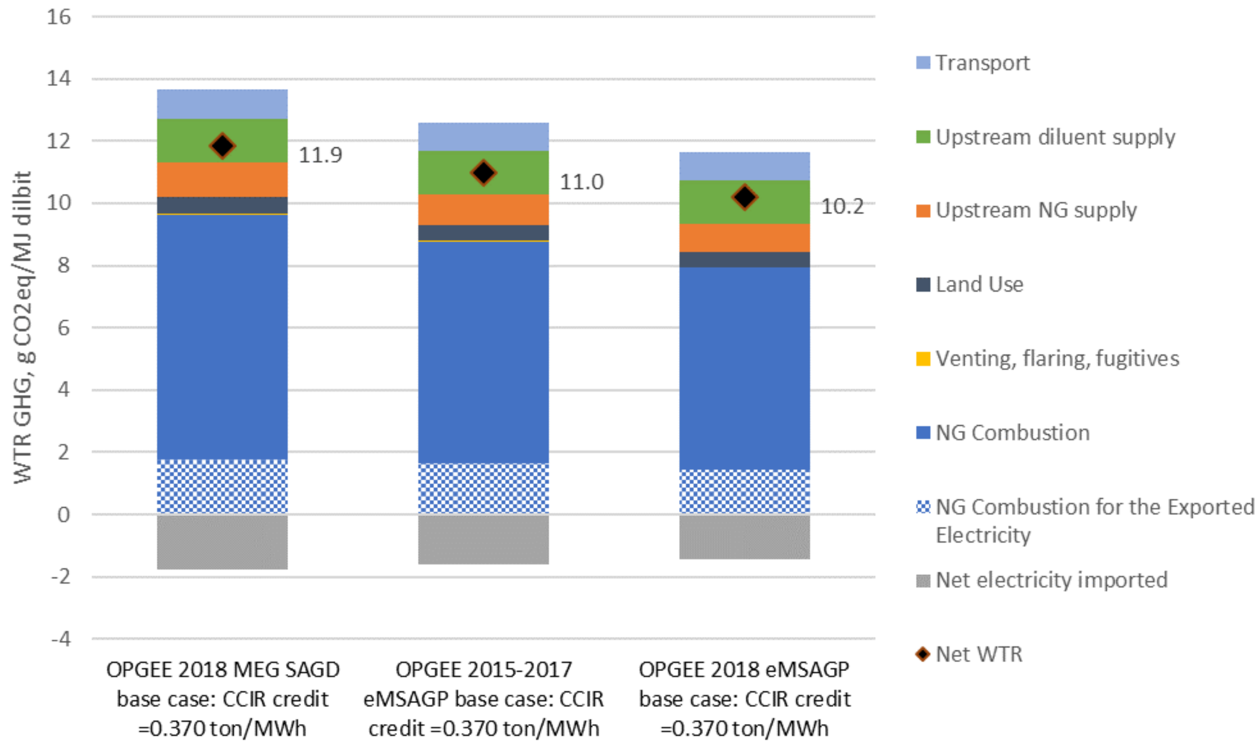


Figure 3-10. Well-to-refinery GHG emissions for MEG eMSAGP pathway.
Stacked bars show breakdown of GHG emissions by source for MEG eMSAGP pathway base case results. The impacts of uncertainty and variability on results are presented in detailed sensitivity analysis, see Figure 3-15).

3.3.5 Imperial SA-SAGD pathway

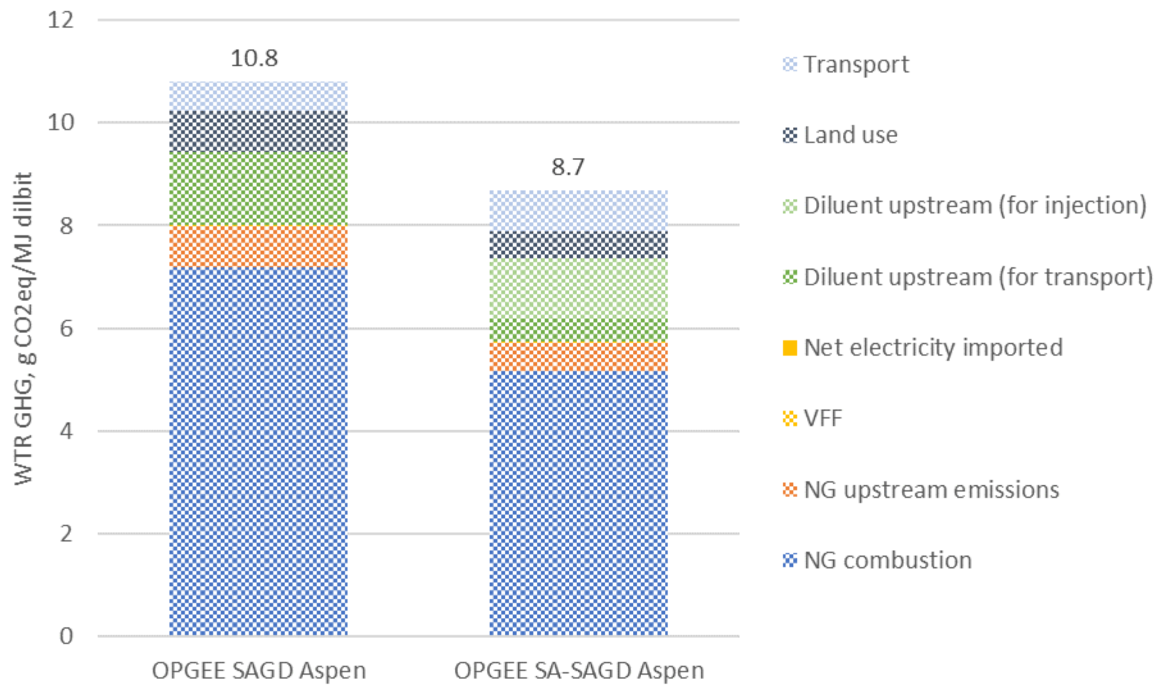


Figure 3-11. Well-to-refinery GHG emissions for Imperial SA-SAGD pathway.
Stacked bars show breakdown of GHG emissions by source for SA-SAGD and reference SAGD pathway base case results based on simulated data from the Aspen SA-SAGD regulatory applications. The impacts of uncertainty and variability on results are presented in detailed sensitivity analysis, see Figure 3-15).

3.4 Sensitivity analysis for well-to-refinery results

Results for the sensitivity analysis on well-to-refinery life cycle stages are presented in Sections 3.4.1 to 3.4.5, below. These sensitivity analyses are based on 2018 operating data for Imperial Kearl, CNRL Horizon, MEG SAGD and eMSAGP pathways (i.e., those based on operating data rather than regulatory application data). Note that parameters explored in the sensitivity analysis are categorized as either parameter uncertainty and variability or model uncertainty and variability. Units in the sensitivity analysis are aligned with those employed in OPGEE, where feasible. The selection of ranges to explore in the sensitivity analysis are described in Methods sections 2.10.9 (upstream), 2.11 (crude transport), 2.12.6 (refining), 2.13 (refined products transport), and 2.14 (refined products combustion).

3.4.1 Imperial Kearl pathway

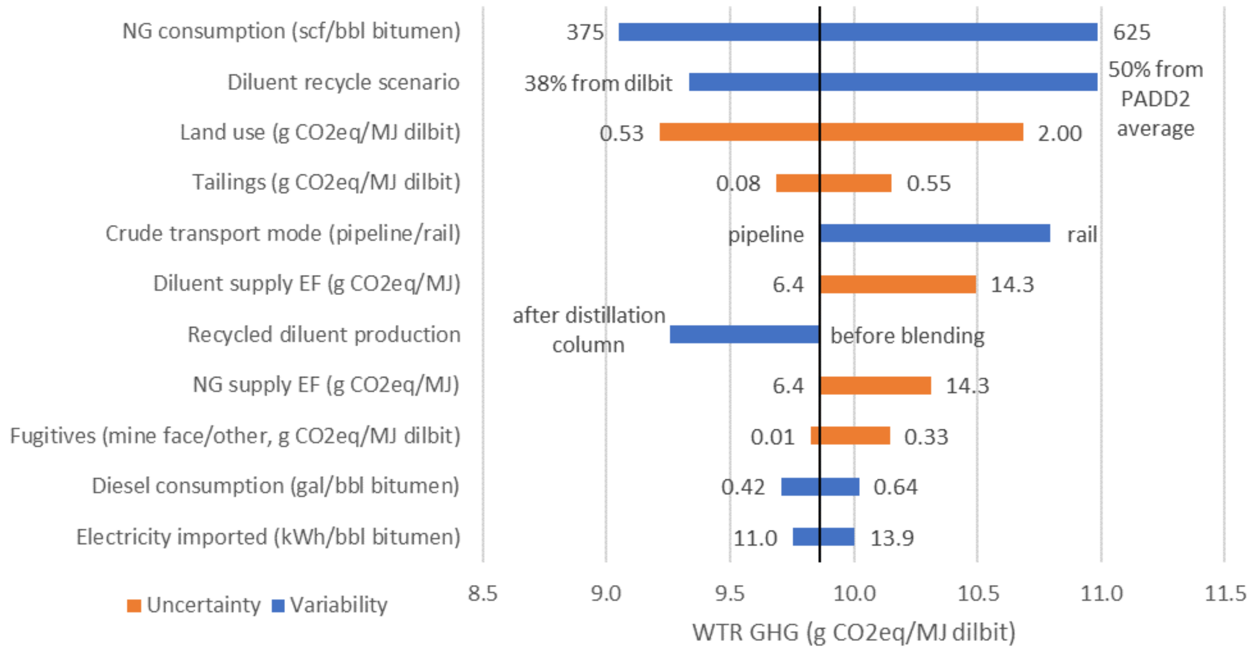


Figure 3-12. Detailed sensitivity analysis for Imperial Kearl pathway well-to-refinery emissions.

3.4.2 CNRL Horizon pathway

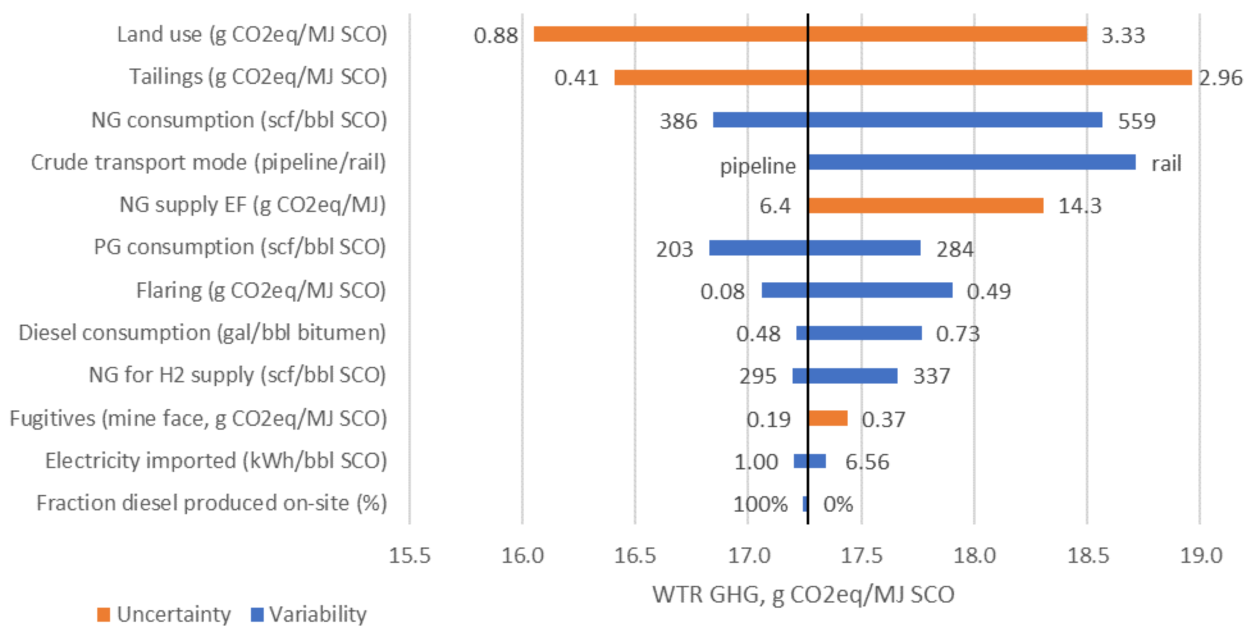


Figure 3-13. Detailed sensitivity analysis for CNRL Horizon pathway well-to-refinery emissions.

3.4.3 MEG Christina Lake SAGD pathway

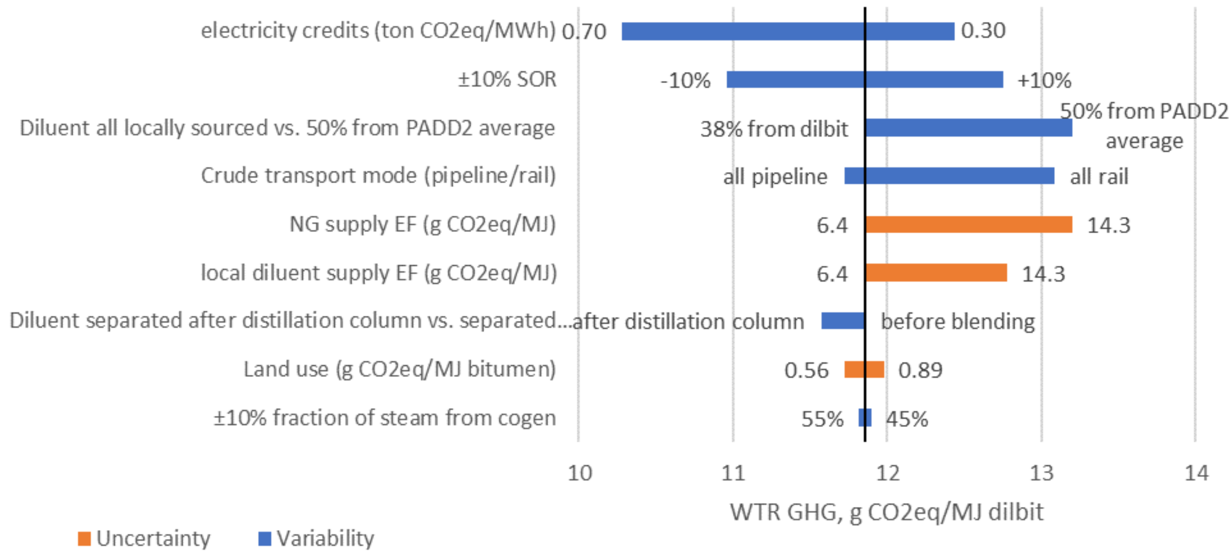


Figure 3-14. Detailed sensitivity analysis for MEG SAGD pathway well-to-refinery emissions.

3.4.4 MEG eMSAGP pathway

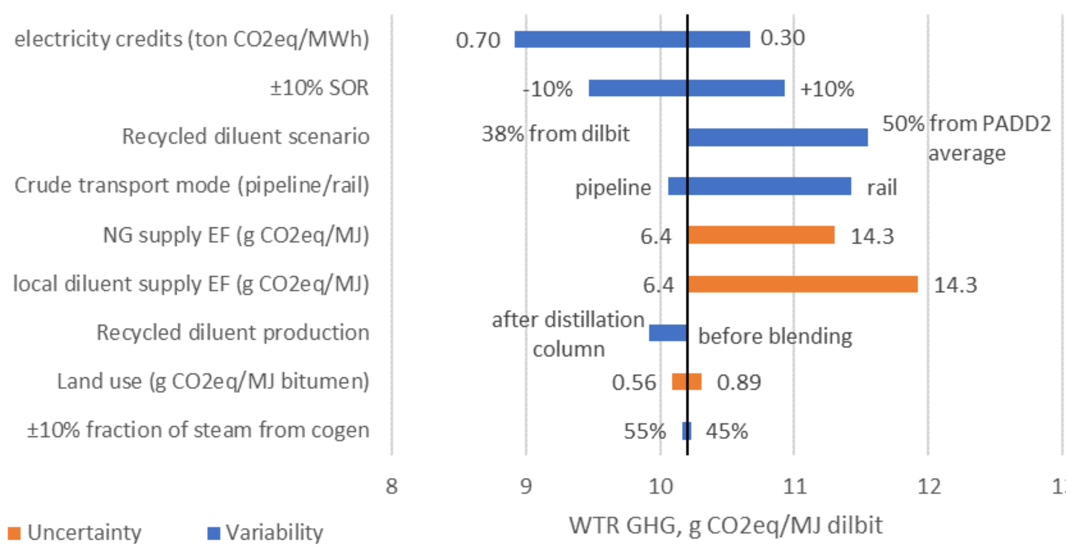


Figure 3-15. Detailed sensitivity analysis for MEG eMSAGP pathway well-to-refinery emissions.

3.4.5 Imperial SA-SAGD pathway

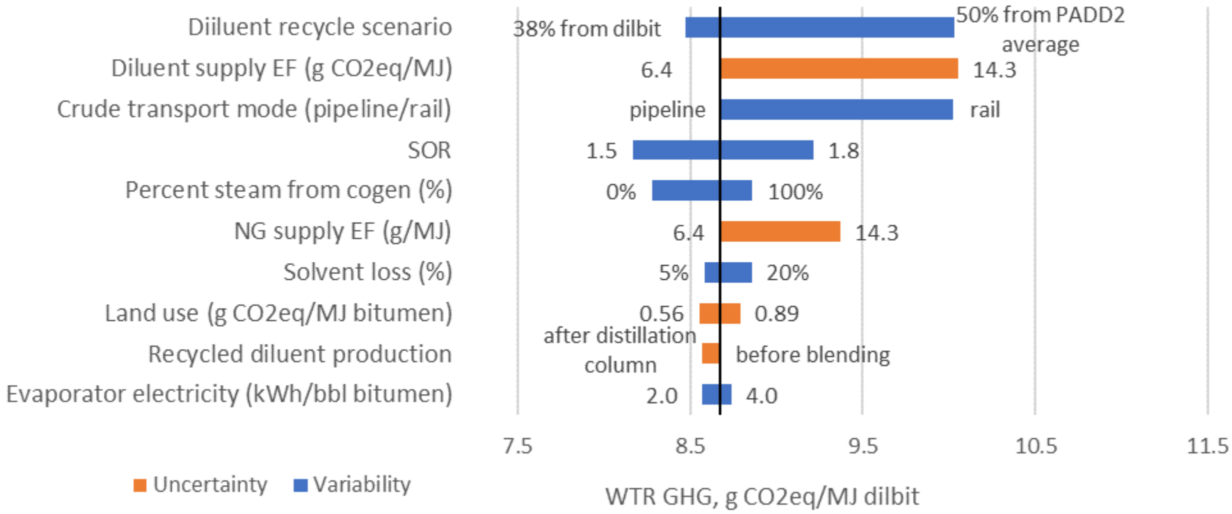


Figure 3-16. Detailed sensitivity analysis for Imperial SA-SAGD pathway well-to-refinery emissions.

3.5 Well-to-tank GHG emissions for current and emerging oil sands pathways

Oil sands pathway WTT (upstream, crude transport, refining, and refined products transport) GHG emissions intensities are compared in Figure 3-17 and Figure 3-18 on a per bbl crude refined and per MJ refinery product produced, respectively. These results are based on 2018 operating data for Imperial Kearl, CNRL Horizon, MEG SAGD and eMSAGP pathways (i.e., those based on operating data rather than regulatory application data). While a range of factors besides API gravity affect refinery emissions, in this study we find that for the crudes considered, higher API gravity crudes have lower refinery emissions on a per bbl basis, partially off-setting the increased upstream emissions for producing SCO in the CNRL pathway (compared to dilbits produced by the other pathways). How pathways compare in terms of their WTT GHG intensity depends on the functional unit considered (i.e., per bbl crude, per MJ gasoline, per MJ diesel, per MJ jet fuel), as each crude will have distinct refinery emissions for producing each refinery product. Note that PRELIM was not evaluated as part of this study and alignment of the assumptions of PRELIM with actual refinery details was not made due to a lack of data.

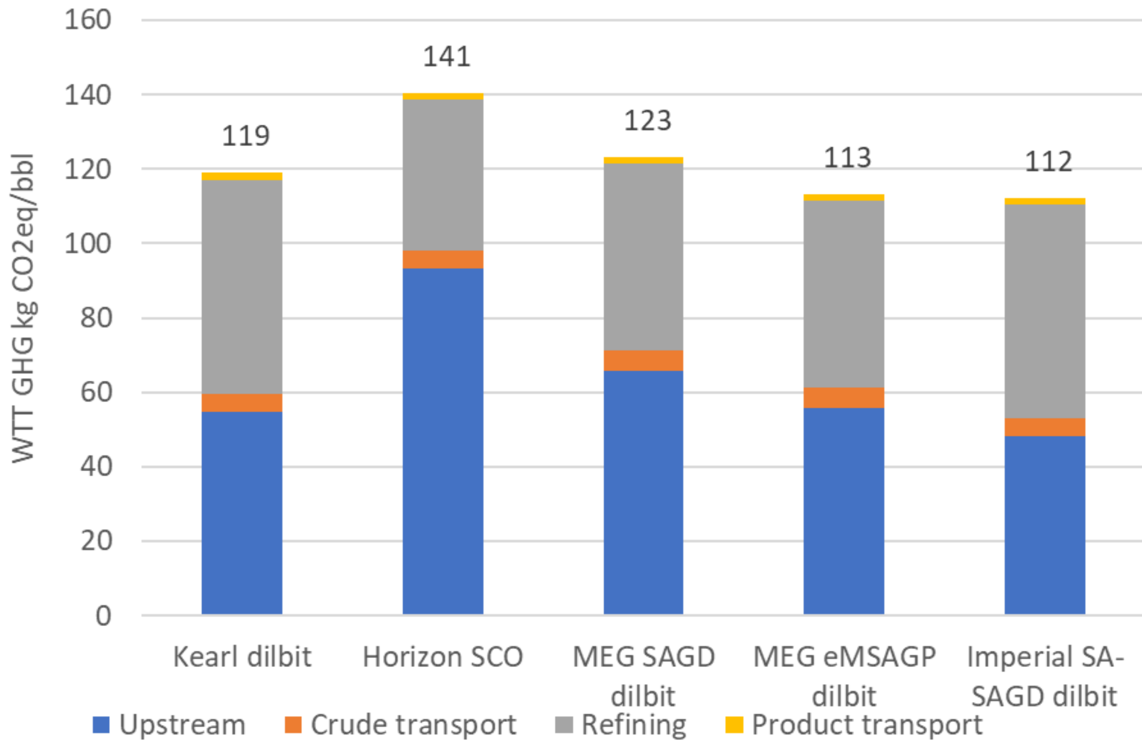


Figure 3-17. Well-to-tank GHG emissions for existing and emerging oil sands pathways per bbl of crude (dilbit or SCO).

Upstream results generated using 2018 operating data (except Imperial's SA-SAGD pathway which is based on regulatory application data). For the base case, dilbit is assumed to be processed in a generic deep conversion (FCC) refinery and SCO is assumed to be processed in a generic medium conversion (FCC) refinery. The impact of refinery configuration on WTW results is tested in the sensitivity analysis.

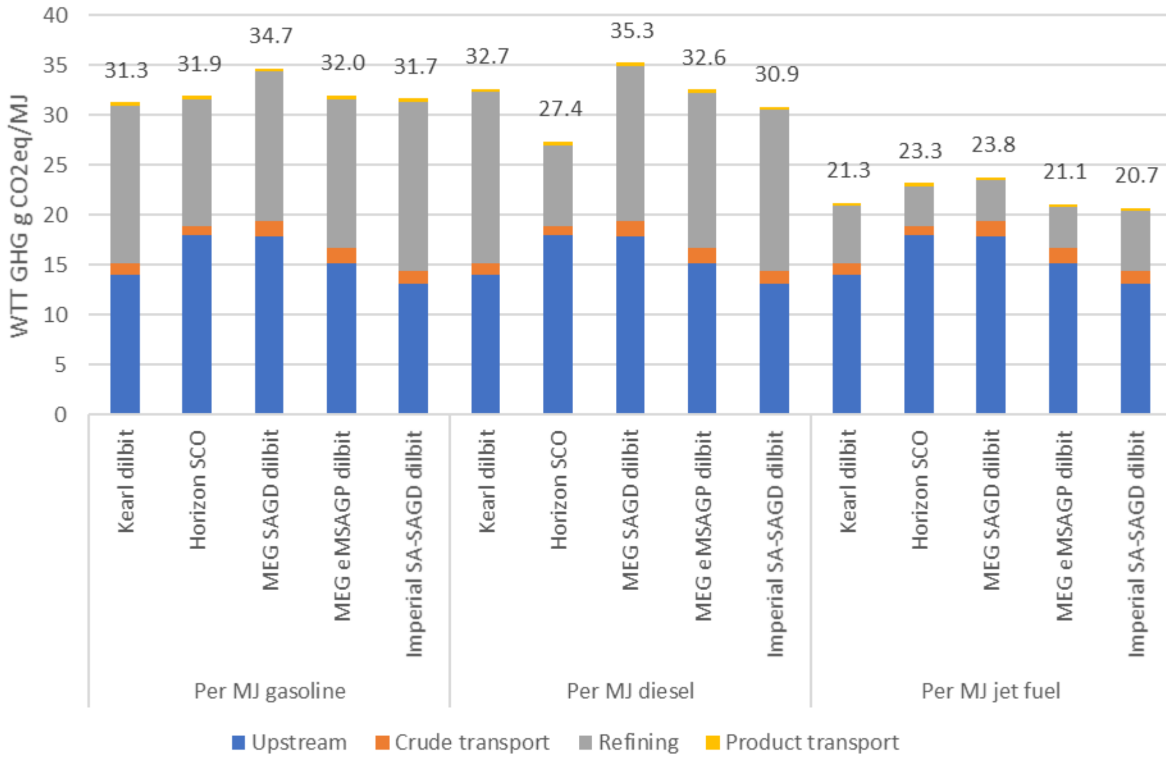


Figure 3-18. Well-to-tank GHG emissions for existing and emerging oil sands pathways per MJ refinery product (gasoline, diesel and jet fuel).
Upstream results generated using 2018 operating data (except Imperial's SA-SAGD pathway which is based on regulatory application data). For the base case, dilbit is assumed to be processed in a generic deep conversion (FCC) refinery and SCO is assumed to be processed in a generic medium conversion (FCC) refinery. The impact of refinery configuration on WTW results is tested in the sensitivity analysis.

3.6 Well-to-wheel GHG emissions intensities for current and emerging oil sands pathways

Oil sands pathway WTW (upstream, crude transport, refining, refined products transport, and combustion) GHG emissions intensities are compared in Figure 3-19 and Figure 3-20 on a per bbl crude refined and per MJ refinery product produced, respectively. These results are based on 2018 operating data for Imperial Kearl, CNRL Horizon, MEG SAGD and eMSAGP pathways (i.e., those based on operating data rather than regulatory application data). Across oil sands pathways, upstream GHG emissions contributions to WTW GHG emissions are between 9.6-17% (on a per bbl crude basis) of WTW GHG emissions. The majority of WTW GHG emissions are from the combustion of refined products (75-78% of WTW emissions on a per bbl crude basis across oil sands pathways). As a result, reductions in upstream emissions intensities between emerging pathways and the SAGD reference pathways appear to have a smaller impact relative to downstream emissions which vary depending on the properties of crude produced. As with WTT emissions, how pathways compare in terms of their WTT GHG intensity depends on the functional unit considered (i.e., per bbl crude, per MJ gasoline, per MJ diesel, per MJ jet fuel), as each crude will have distinct refinery emissions for producing each refinery product.

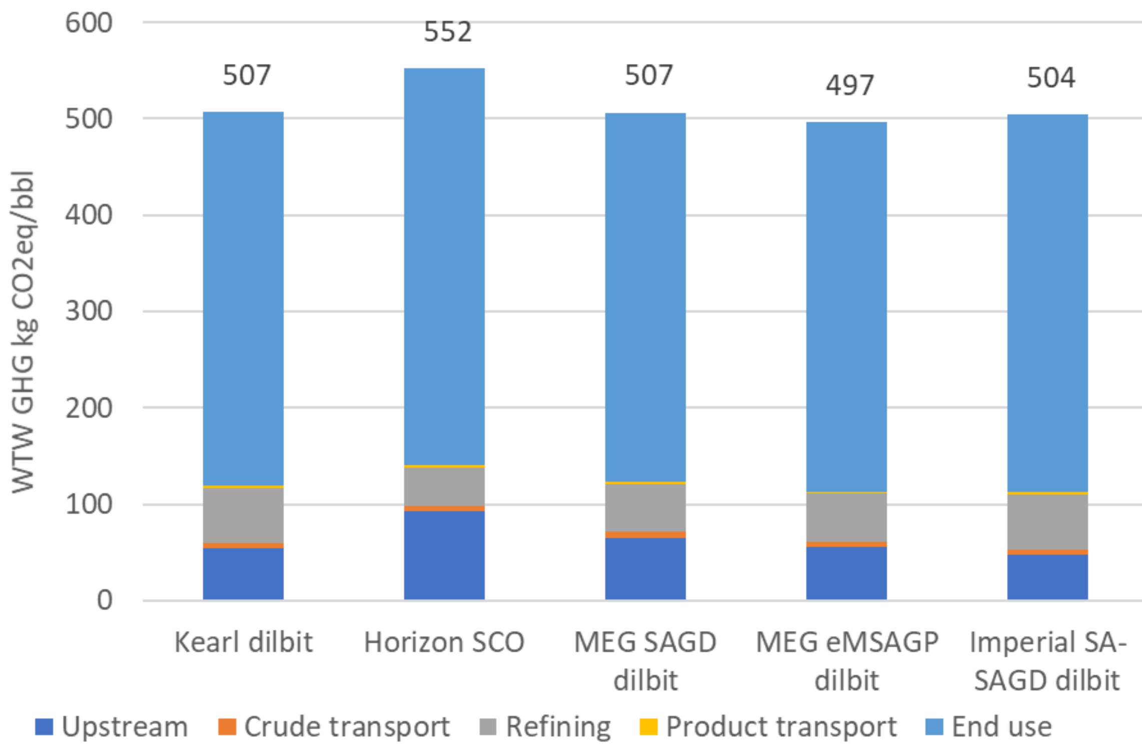


Figure 3-19. Well-to-wheel GHG intensities for existing and emerging oil sands pathways per bbl of crude (dilbit or SCO).

Upstream results generated using 2018 operating data (except Imperial's SA-SAGD pathway which is based on regulatory application data). For the base case, dilbit is assumed to be processed in a generic deep conversion (FCC) refinery and SCO is assumed to be processed in a generic medium conversion (FCC) refinery. The impact of refinery configuration on WTW results is tested in the sensitivity analysis.

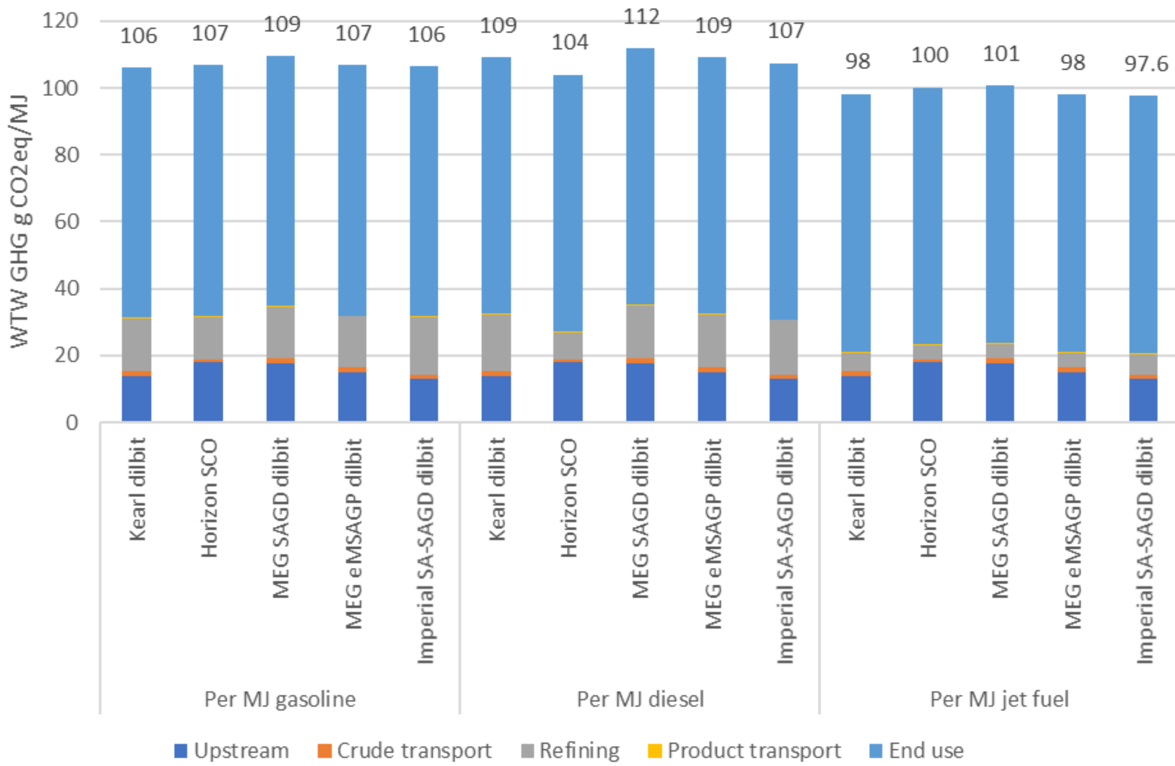


Figure 3-20. Well-to-wheel GHG intensities for existing and emerging oil sands pathways per MJ refinery product (gasoline, diesel, jet fuel).

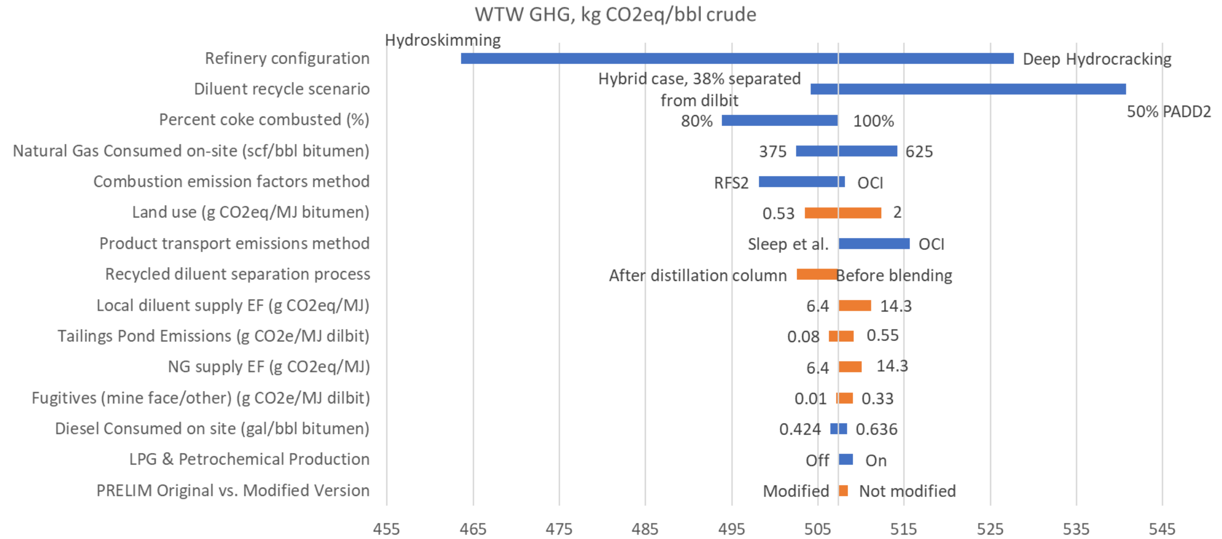
Upstream results generated using 2018 operating data (except Imperial's SA-SAGD pathway which is based on regulatory application data). For the base case, dilbit is assumed to be processed in a generic deep conversion (FCC) refinery and SCO is assumed to be processed in a generic medium conversion (FCC) refinery. The impact of refinery configuration on WTW results is tested in the sensitivity analysis.

3.7 Sensitivity of WTW GHG intensities to variability and uncertainty in model inputs across the life cycle

The following section contains an overview of the key sensitivity analysis results for the full WTW. Sensitivity analysis results are presented for two functional units: per barrel of crude (Figure 3-21 and Figure 3-22) and per MJ of gasoline (Figure 3-23 and Figure 3-24). Across pathways, refinery configuration and diluent recycle scenario (i.e., whether recycled diluent is sourced from the bbl dilbit sent to the refinery or a PADD2-average bbl of crude, applies to dilution pathways only) consistently rank as the two parameters with the biggest impact on WTW GHG emissions intensity estimates, both per bbl crude and per MJ gasoline. Relative to downstream variability, sensitivity to emissions due to uncertainty in upstream parameters such as fugitive and land use emissions have less impact on uncertainty and variability over the WTW. Note that some refinery sensitivity parameters (e.g., refinery configuration) reduce emissions on a per bbl crude basis but increase emissions on a per MJ gasoline basis, depending on how the parameter affects how the crude is processed in the refinery.

A hydroskimming refinery configuration is included in the sensitivity analysis as a low-end estimate of sensitivity of refinery emissions. While processing an oil sands-derived crude in a hydroskimming refinery is technically possible, hydroskimming refineries process only the crude oil from the atmospheric tower into refined products with no additional transformation of the crude (Abella et al. 2019). As a result, the yield of higher-value refinery products (i.e., gasoline, diesel, jet fuel) from a hydroskimming refinery processing oil sands-derived crude would be very low, making it unlikely that oil sands-derived crudes would be processed in this type of refinery.

a) Imperial Kearl pathway



b) CNRL Horizon pathway

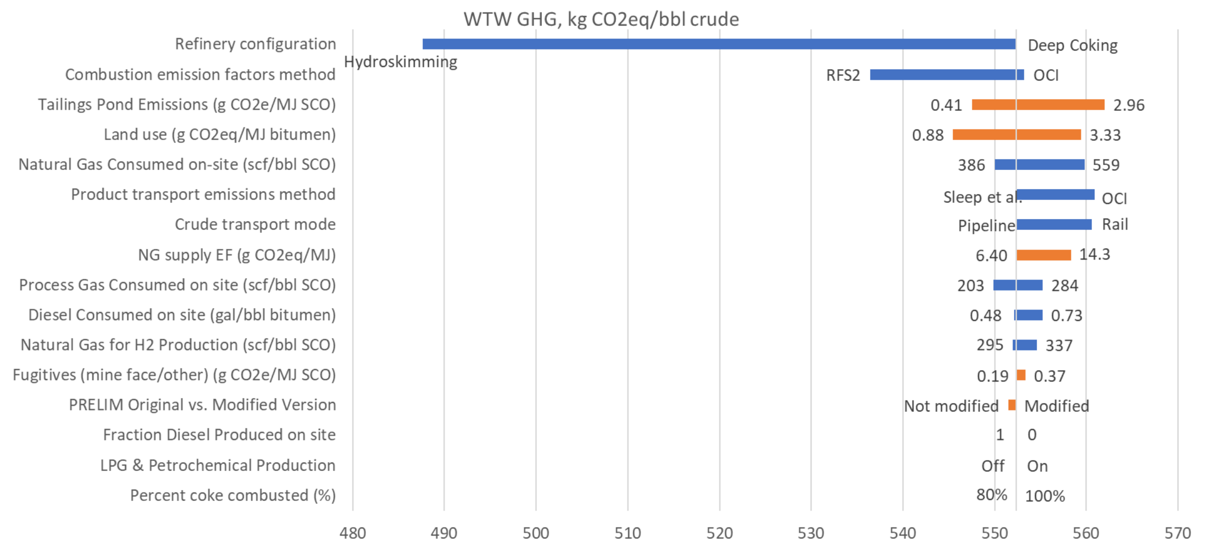
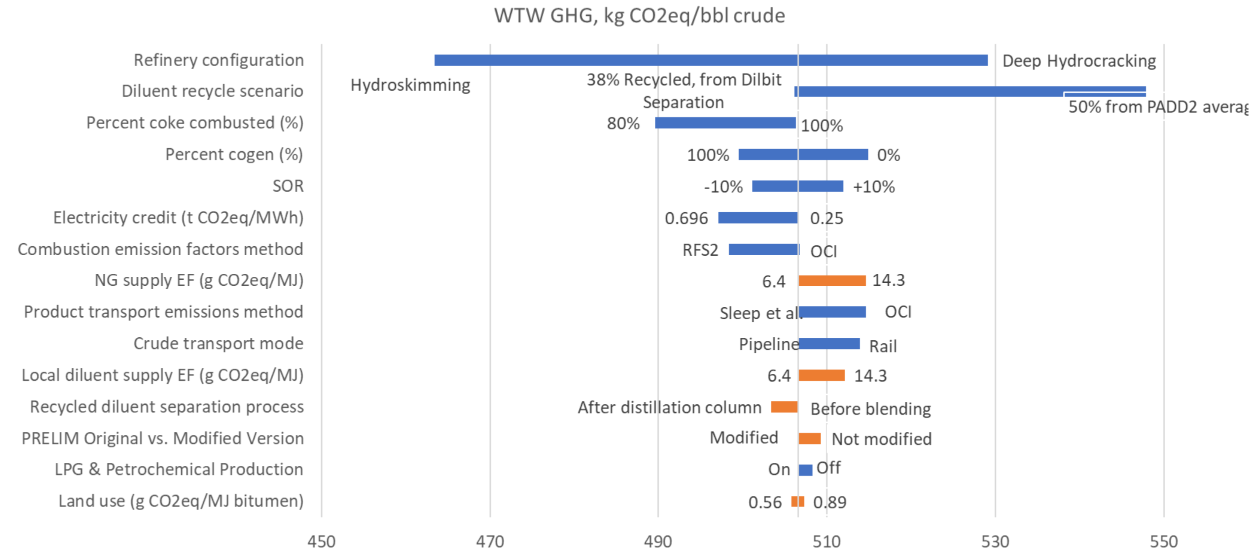
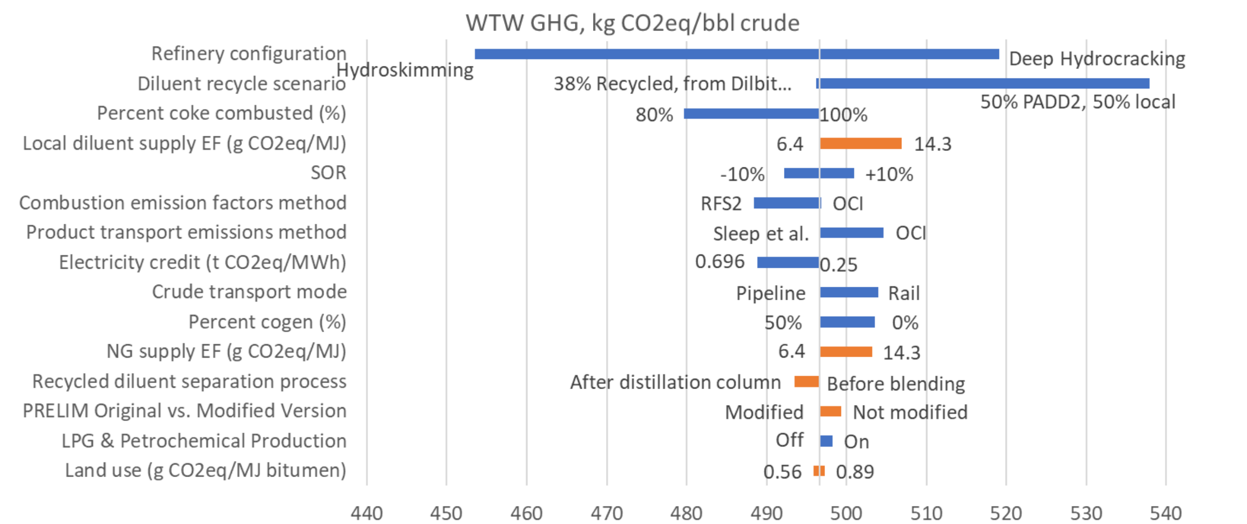


Figure 3-21. Sensitivity of WTW results to uncertainty and variability in model inputs for oil sands mining pathways. Results are presented per bbl of crude refined.

a) MEG SAGD pathway



b) MEG eMSAGP pathway



c) Imperial SA-SAGD pathway

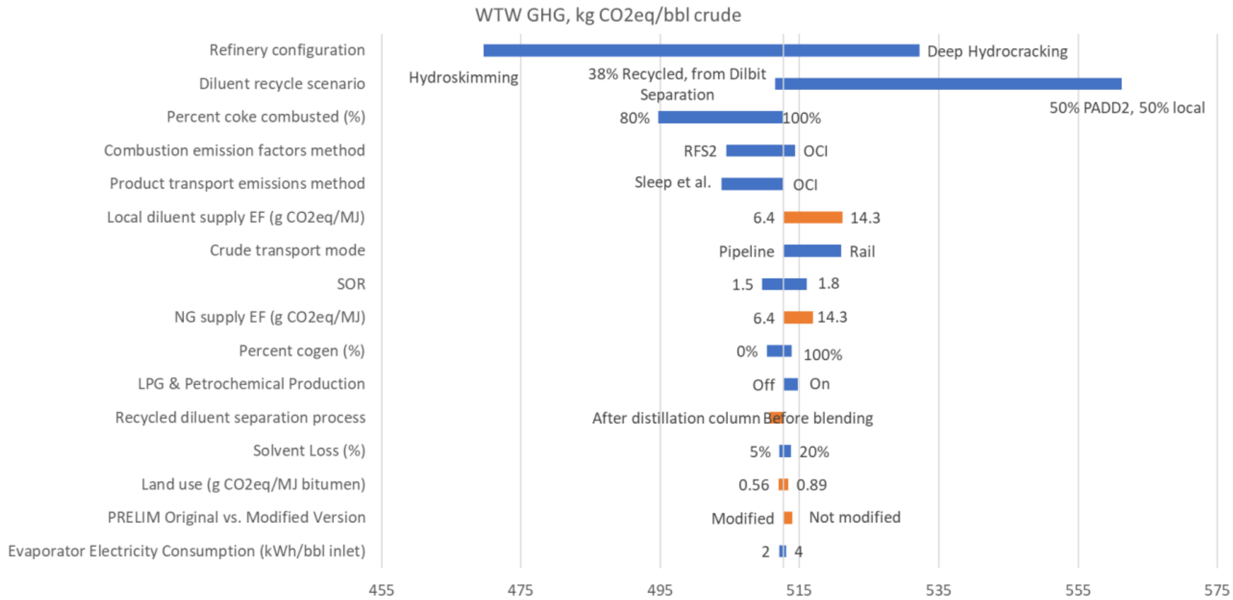
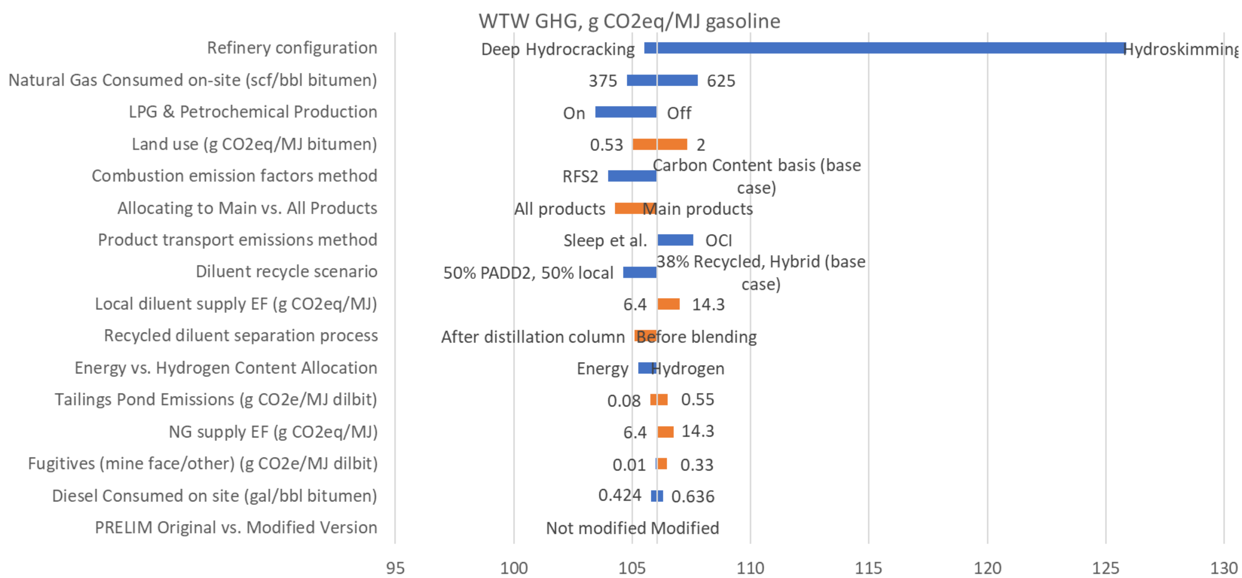


Figure 3-22. Sensitivity of WTW results to uncertainty and variability in model inputs for in situ pathways. Results are presented per bbl of crude refined.

a) Imperial Kearl pathway



b) CNRL Horizon pathway

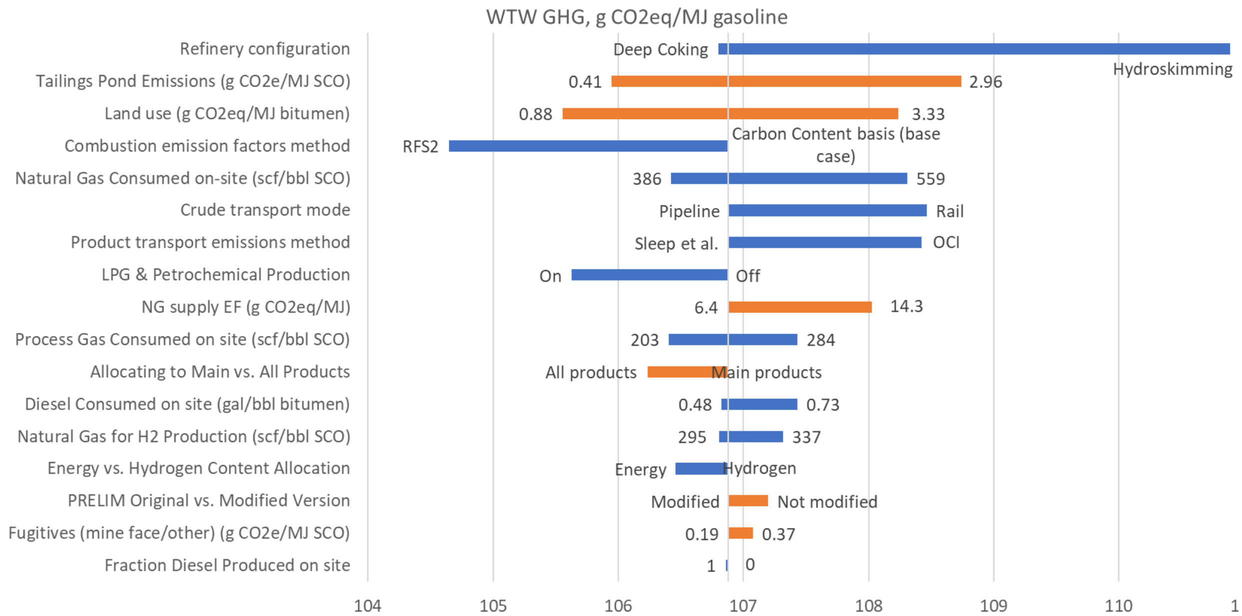
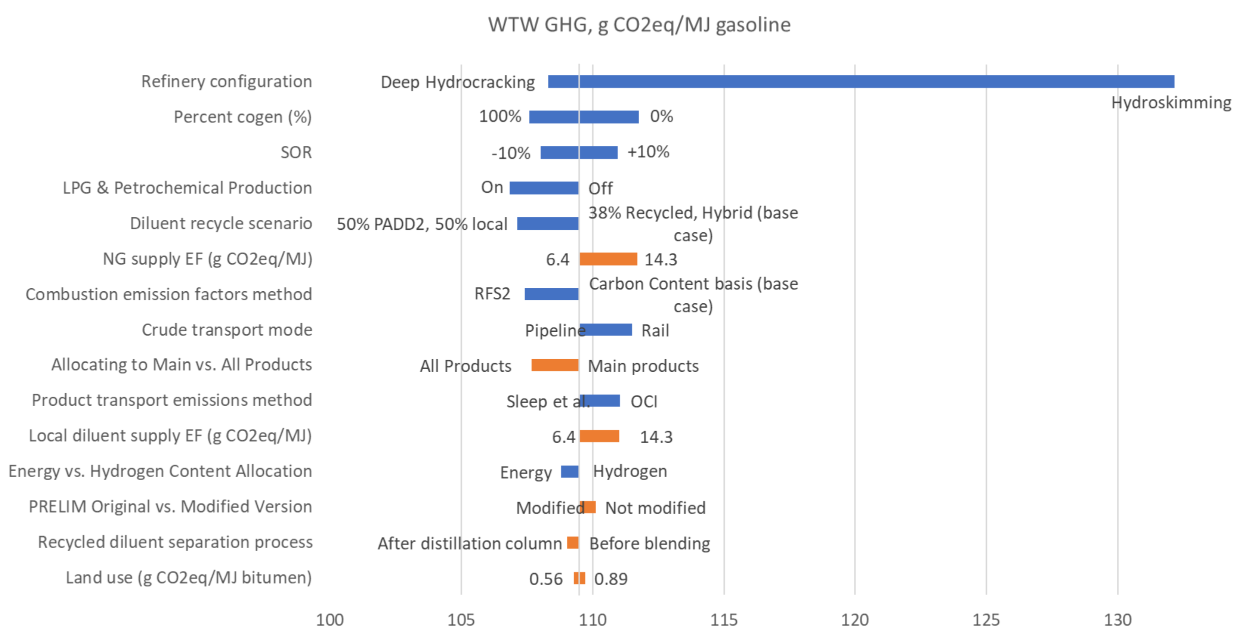
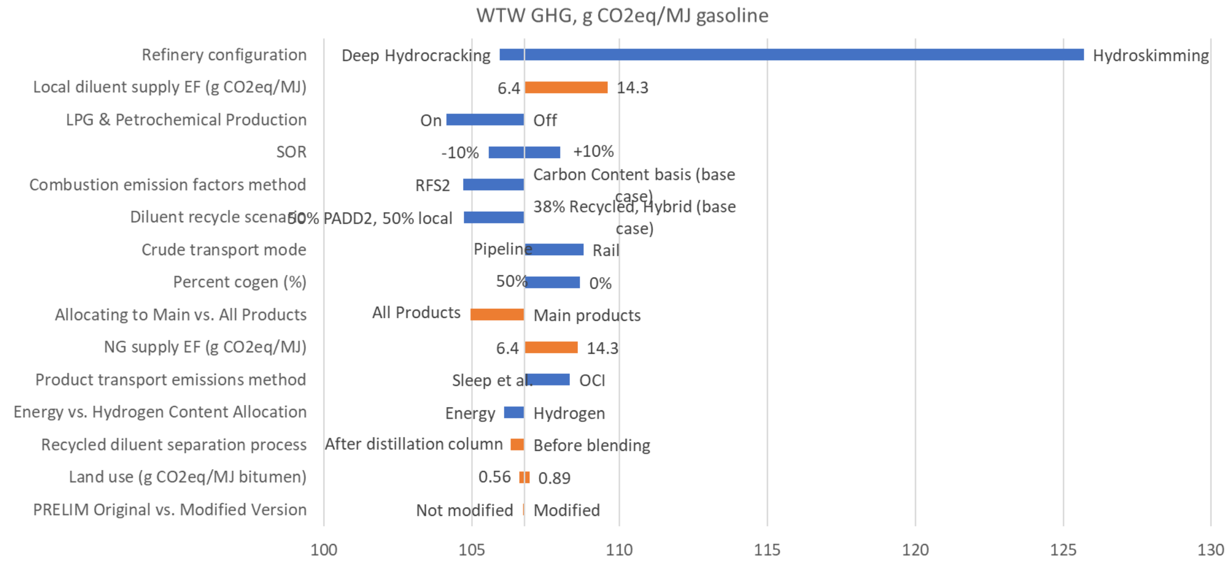


Figure 3-23. Sensitivity of WTW results to uncertainty and variability in model inputs for oil sands mining pathways. Results are presented per MJ of gasoline produced

a) MEG SAGD pathway



Sb) MEG eMSAGP pathway



c) Imperial SA-SAGD pathway

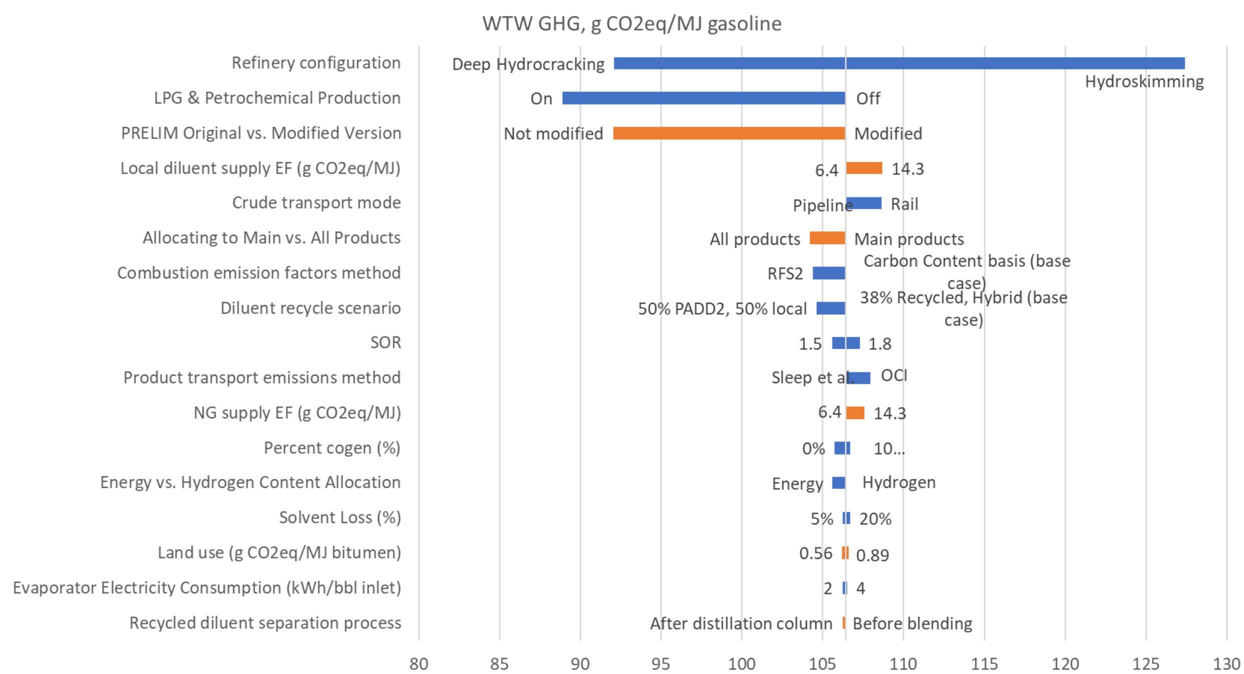


Figure 3-24. Sensitivity of WTW results to uncertainty and variability in model inputs for in situ pathways. Results are presented per MJ of gasoline produced.

3.8 Updates to OPGEE

The following changes were made to the OPGEE model as a result of this project. These will be incorporated into OPGEE 3.0.

Four types of updates are made to better represent the oil sands pathways in OPGEE as outlined in Section 2.3.1.

3.8.1 Modifications to SAGD modeling approach

These modifications have been or are proposed for incorporation into OPGEE 3.0:

1. Redesigned steam generation module: The steam generation module depicted in Figure 2.1 (the OPGEE process diagram) was re-designed to allow more detailed calculations and more heat recovery potential via air pre-heaters, economizers, and blowdown water heat recovery, as well as to better characterize cogeneration units.
2. Available blowdown water treatment: To comply with Alberta's water usage policies, most in situ projects recycle a large portion of the blowdown water. A stream going from the steam generation module to produced water and blowdown water treatment module (Figure 2.1) has been added to OPGEE 3.0 to allow blowdown water treatment at a user-specified recycling rate.
3. Included more water treatment technologies: Blowdown water has a high concentration of dissolved solids and requires water treatment processes which are typically energy intensive. For example, Imperial proposed using an evaporator to treat the blowdown water. An evaporator option has been added as a water treatment option in OPGEE 3.0 based on energy intensity presented in COSIA templates.
4. An alternative method of modeling heavy oil dilution has been added: OPGEE 3.0 calculates dilbit heating values based on diluent heating value, bitumen heating value, and volumetric fraction of diluent. As described in section 2.11.5, diluent sourcing is uncertain and variable. In practice, it is sometimes harder to determine the heating value of diluent used than to decide on a dilbit heating value. Therefore, an alternative method of modeling heavy oil dilution is proposed. Rather than always treating dilbit heating value as a free variable, users can now decide between choosing dilbit heating value or diluent heating value as the input variable based on the relative confidence in data sources of the two values.

3.8.2 Updates to OPGEE input parameters to better reflect the Alberta context

OPGEE typically employs generic inputs that do not account for regional variability. For this study, where appropriate, inputs are updated to Alberta-specific values. These changes from generic defaults listed in Table 3-2 will not be incorporated into OPGEE 3.0 because the OPGEE model does not typically account for region-specific inputs.

Table 3-2. OPGEE input parameters customized for Alberta oil sands.

Parameters	OPGEE default	Alberta-specific value	Data sources and notes of Alberta-specific value
Electricity import credit	0.549 t CO2eq/MWh	0.696 t CO2eq/MWh	Alberta Government 2018
Electricity export credit	0.549 t CO2eq/MWh	0.418 t CO2eq/MWh	Alberta Environment 2018
Upstream natural gas emission factor	14.3 g CO2eq/MJ	6.4 g CO2eq/MJ	Senobari 2016

Upstream (local) diluent emission factor	14.3 g CO2eq/MJ	6.4 g CO2eq/MJ	Senobari 2016
In situ land use emissions	Model based on Yeh 2010: land use intensity based on field development intensity and crude ecosystem carbon richness and	0.73 g CO2eq/MJ	Yeh 2015
Miscellaneous emissions	0.5 g CO2eq/MJ	0 g CO2eq/MJ	Section 2.11.4

3.8.3 Updates to OPGEE's generic energy inputs

Updates to generic energy inputs for each oil sands pathway (e.g., energy consumed in mining projects with integrated upgrader) to reflect recent operations assessed in this project are presented in Appendix B. These will not be incorporated into OPGEE 3.0 because the current inputs to OPGEE are intended to be representative of typical operations within each pathway rather than the specific projects included in this study.

3.8.4 Modifications to incorporate emerging in situ pathways

There are three existing steam flooding options available in OPGEE 3.0, cyclic steam simulation (CSS), steam flooding (SF), and SAGD. It is proposed that eMSAGP and SA-SAGD be incorporated into OPGEE in addition to the three existing pathways.

Additionally, "smart default" values are proposed to be automatically used when the emerging technologies are selected by users. These defaults are listed in Table 3-3.

Table 3-3. OPGEE default values when emerging in-situ technologies are selected

Parameters	CSS & SF defaults[1]	SAGD defaults	eMSAGP defaults	SA-SAGD defaults
Produced gas composition[2]	OPGEE default	OPGEE default	Gas composition test results by Maxxam and MEG	OPGEE default
Fraction of produced gas in total gas fed into OTSG and cogeneration[3]	0.1	0.1	0.25	0.1
Desired steam quality[4]	0.7	0.95	0.95	0.95
Steam quality at generator outlet[5]	0.7	0.7	0.7	0.8
Fraction of blowdown water recycled	0	0.7	0.7	0.7
Blowdown water treatment technology	N/A	N/A	N/A	evaporator

[1]CSS and SF have the same set of smart default values in OPGEE 3.0. [2]Produced gas from eMSAGP wells is a combination of solution gas and recovered natural gas for injection, as opposed to be solely comprised of solution gas in the cases of other technologies. [3]Natural gas is first injected into the eMSAGP wells before being recovered and fed into steam generators or turbines. Hence, by default eMSAGP practices generate more "produced gas" and should be associated with a greater fraction of produced gas of total fuel. [4]SF and CSS in general require lower quality steam than other types of in situ pathways due to their differences in specialties to recover oil from different reservoir formations. Although a desired steam quality of 1 is used for SAGD, eMSAGP, and SA-SAGD in this study, the default is set to be 0.95. [5]By Imperial's design, SA-SAGD uses boilers in series to achieve higher steam quality at generator outlet and lower flow rate of blowdown water. In lieu of modeling boilers in series, a higher steam quality is assigned to SA-SAGD's steam generators by default.

3.9 Comparison to Other Studies

Each study that has previously estimated life cycle GHG emissions intensities from fuels produced from oil sands-derived crudes is distinct in terms of its goal, scope, boundaries, data employed, projects or pathways characterized, modelling approaches used, and assumptions made throughout the study. Without some alignment of boundaries, assumptions, etc., no two studies can be directly compared (not an apples-to-apples comparison).

This study presents data that has been focused on steady state operations and use of data that best reflects the Alberta context. While we have used the same open-source tool (e.g., OPGEE) employed in other life cycle studies of petroleum-derived crudes (e.g., Masnadi et al. 2018; Gordon et al. 2015), several changes were made to the model to both adapt the model to represent the Alberta context and to generate (in consultation with companies), the most accurate representation of their specific project operations using data available at the time of the study. Below is an overview of the general steps taken to facilitate a comparison between this study's results and the oil sands pathways characterized in Masnadi et al.

While we have attempted to represent the Alberta context, the comparison below is not intended to imply that in all cases our representation of the Alberta context represents better data than was employed in Masnadi et al., just the primary factors contributing to differences between the two studies and the comparison between the projects modelled in this study and the more general oil sands pathways modelled in Masnadi et al. As Masnadi et al. characterizes WTR emissions across the globe, limited data availability in other jurisdictions and the number of projects characterized prevented detailed representation of the regional context (e.g., upstream emissions factors, crude transport distances from production site to refinery) in their study. Some Alberta-specific inputs employed in this study (particularly natural gas upstream emissions intensity and diluent recycling scenarios) are still approximations with significant uncertainty and require further investigation.

3.9.1 Comparison between results of this study and representation of oil sands pathways in Masnadi et al. (2018)

Figure 3-25 through Figure 3-28 below show the differences between the Masnadi et al. (2018) quantification of oil sands WTR GHG emissions intensities and base case 2018 WTR GHG emissions intensities estimated in this study for Imperial Kearl, CNRL Horizon, MEG SAGD/eMSAGP, and Imperial SAGD/SA-SAGD pathways. Generally, across pathways the biggest change that is seen in estimates between Masnadi et al. and the current study is due to assumptions of upstream natural gas emissions intensity, diluent sourcing assumptions, transport distances and land use emissions assumptions. Some of these factors have been made more reflective of the Alberta context (e.g., a more representative assumption about the emissions intensity of the production, processing and transport of the natural gas that is consumed) while others are assumptions about a specific case of a specific project. For example, in this study we assume in the base case that the crude oil is transported by pipeline to PADD 2 (the Chicago area). This is grounded in the assumption that the largest portion of oil sands-derived crudes are processed in PADD 2 (approximately 70% in 2018, U.S. EIA 2019). At the time of this study, oil sands-derived crudes are processed in multiple PADDs throughout the US and are anticipated to be shipped overseas in the future. These point estimates should be considered as a single case among many scenarios that could be used to represent current operations. Other current situations and potential future scenarios are considered in the sensitivity analysis but are considered examples of variation that is plausible, not a comprehensive or detailed forecast.

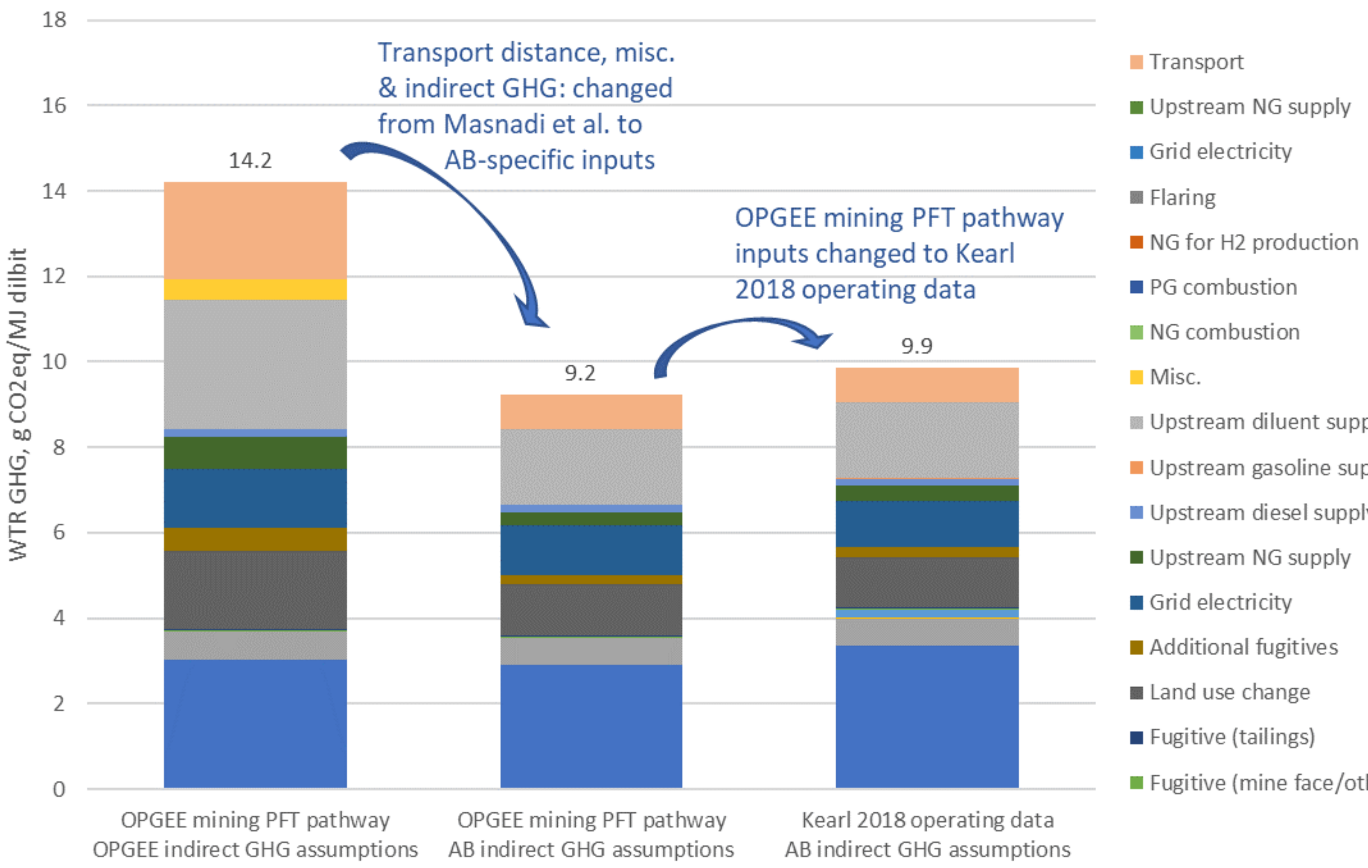


Figure 3-25. Comparison of OPGEE's mining PFT pathway's WTR GHG emissions intensity aligned with Masnadi et al. assumptions to Kearl 2018 base case WTR GHG emissions intensity estimate from this study.

Differences between this study and Masnadi et al. are characterized into two types: 1) changes from generic OPGEE inputs (upstream natural gas and electricity emissions factors, land use change emissions) and Masnadi assumptions (diluent fraction API gravity of crude produced, crude transport distance, miscellaneous emissions) to represent the Alberta context and 2) changes from a generic OPGEE mining PFT pathway to Kearl-specific operating data from 2018. Uncertainty and variability are present in both OPGEE and Masnadi's generic inputs and assumptions as well as Alberta-specific inputs. Uncertainty and variability are not documented here but are explored in the sensitivity analysis.

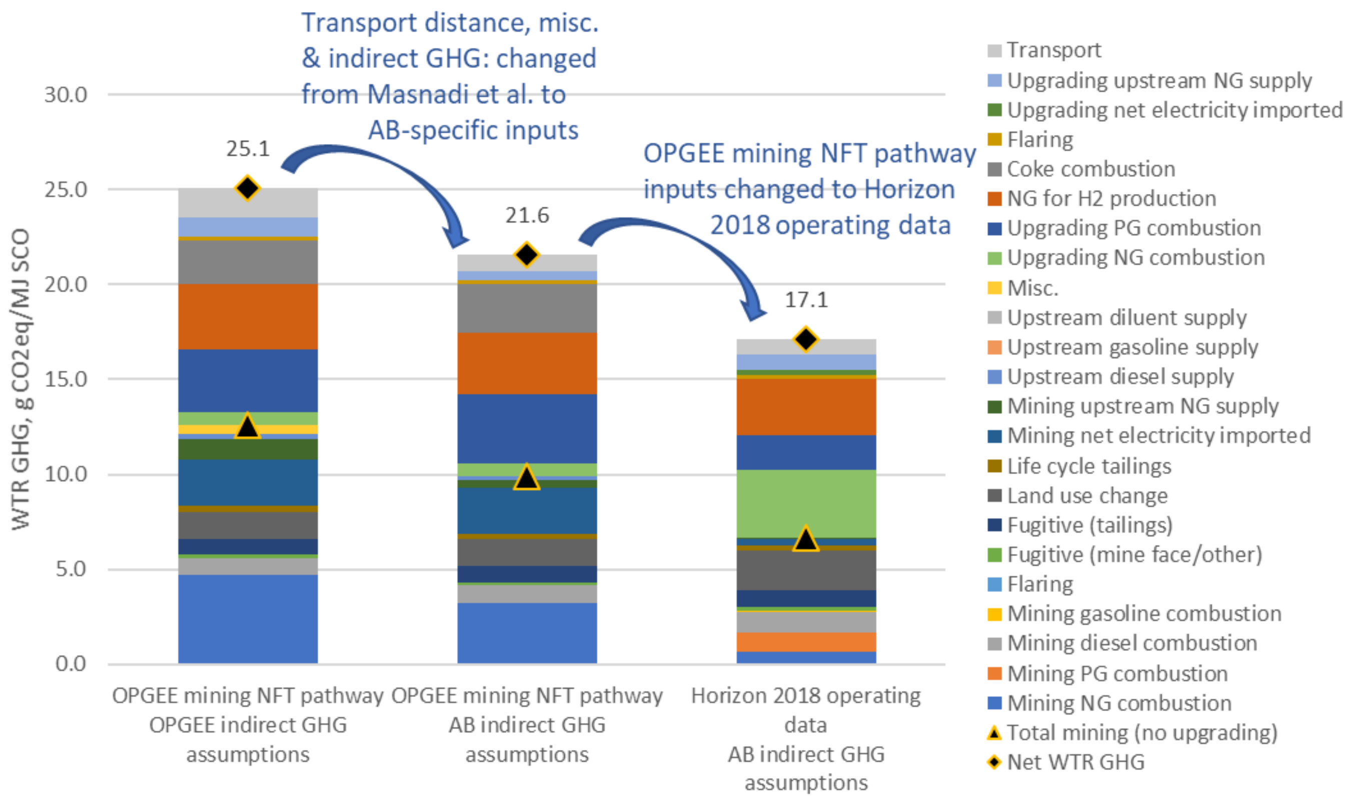


Figure 3-26. Comparison of OPGEE's mining NFT pathway's WTR GHG emissions intensity aligned with OPGEE's indirect GHG assumptions to Horizon 2018 base case WTR GHG emissions intensity estimate from this study.

Differences between this study and Masnadi et al. are characterized into two types: 1) changes from generic OPGEE inputs (upstream natural gas and electricity emissions factors, land use change emissions) and Masnadi assumptions (crude transport distance, miscellaneous emissions) to represent the Alberta context and 2) changes from a generic OPGEE mining NFT pathway to Horizon-specific operating data from 2018. Uncertainty and variability are present in both OPGEE and Masnadi's generic inputs and assumptions as well as Alberta-specific inputs. Uncertainty and variability are not documented here but is explored in the sensitivity analysis.

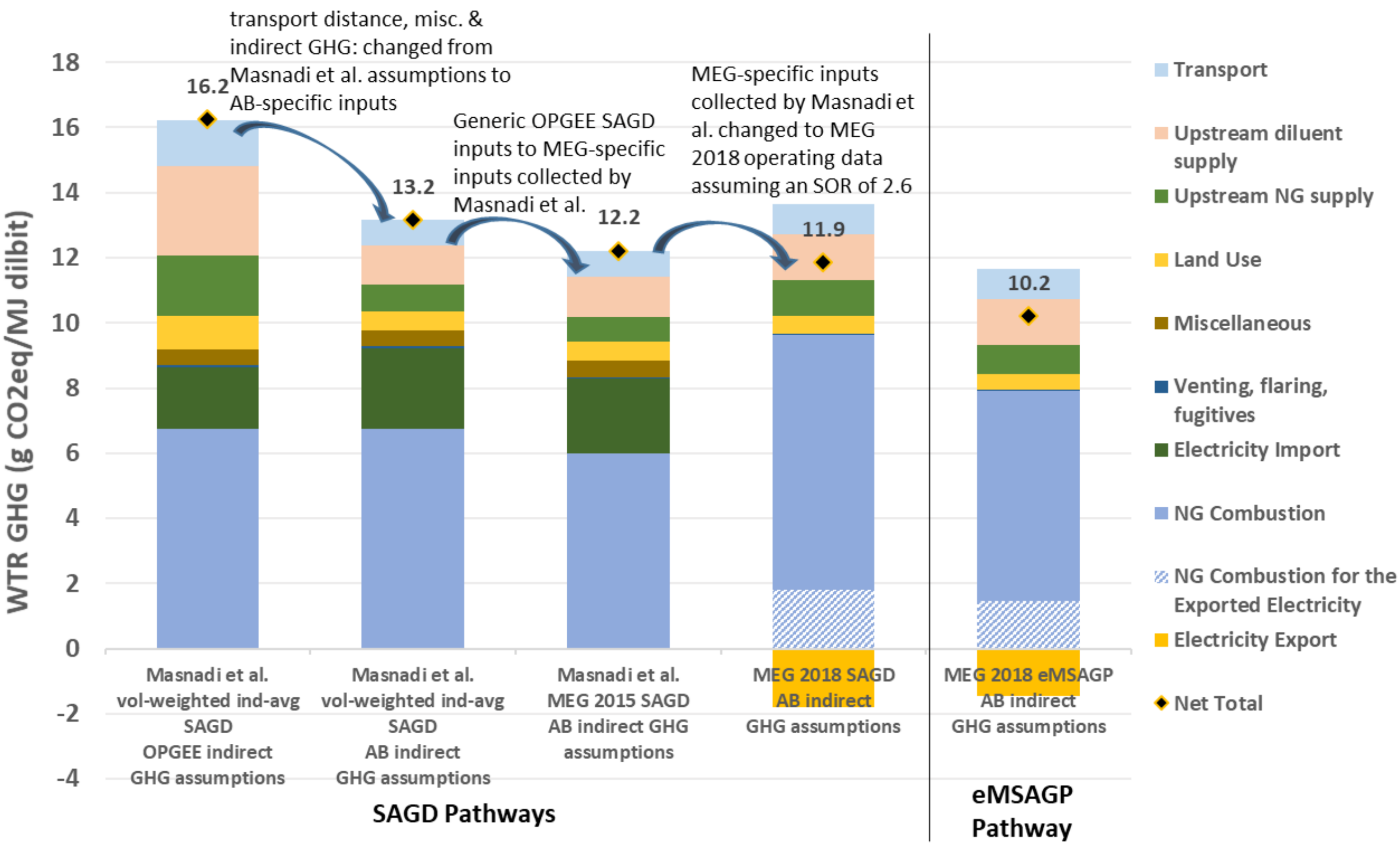


Figure 3-27. Comparison of Masnadi's volume-weighted industry-average 2015 SAGD pathway's WTR GHG emissions intensity aligned with OPGEE indirect GHG assumptions to MEG's 2018 SAGD and eMSAGP emissions intensity estimates from this study. All estimates are generated using OPGEE.

Differences between this study and Masnadi et al. are characterized into two types: 1) changes from generic OPGEE inputs (upstream natural gas and electricity emissions factors, land use change emissions) and Masnadi assumptions (diluent fraction API gravity of crude produced, crude transport distance, miscellaneous emissions) to represent the Alberta context and 2) changes from a generic industry-average SAGD pathway generated using 2015 operating data to MEG-specific operating data from 2018. Uncertainty and variability are present in both OPGEE and Masnadi's generic inputs and assumptions as well as Alberta-specific inputs. Uncertainty and variability are not documented here but is explored in the sensitivity analysis.

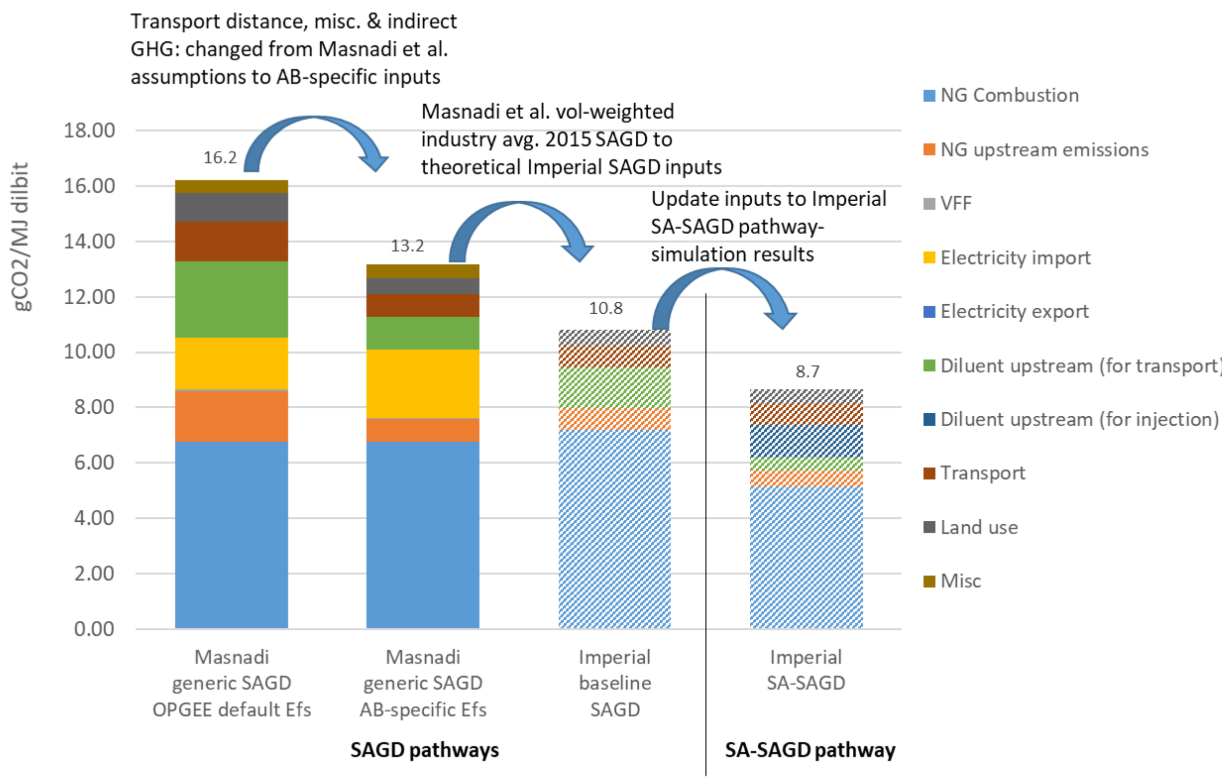


Figure 3-28. Comparison Masnadi's volume-weighted industry-average 2015 SAGD pathway's WTR GHG emissions intensity with OPGEE indirect GHG assumptions to theoretical Imperial Aspen SAGD and SA-SAGD base case WTR GHG emissions intensity estimate from this study. Differences between this study and Masnadi et al. are characterized into two types: 1) changes from generic OPGEE inputs (upstream natural gas and electricity emissions factors, land use change emissions) and Masnadi assumptions (diluent fraction API gravity of crude produced, crude transport distance, miscellaneous emissions) to represent the Alberta context and 2) changes from a generic industry-average SAGD pathway generated using 2015 operating data to Imperial SAGD/SA-SAGD-specific simulated data from Aspen SA-SAGD regulatory applications. Uncertainty and variability are present in both OPGEE and Masnadi's generic inputs and assumptions as well as Alberta-specific inputs. Uncertainty and variability are not documented here but is explored in the sensitivity analysis.

This study assesses oil sands projects that are considered "above-average performers". This can be seen when the project specific estimates are compared to the volume weighted industry average (column 2 and 1 respective in the Figures 1-2 and 1-3). For the mined NFT SCO pathway, changing from the OPGEE default mining NFT and delayed coking upgrading inputs to CNRL Horizon's above-average performing project using 2018 operating data reduces WTR GHG emissions intensity by 4.5 g CO_2eq/MJ SCO (from 21.6 to 17.1 g CO_2eq/MJ). For the OPGEE/Masnadi et al. SAGD pathway, changing from the OPGEE/Masnadi et al. volume-weighted industry-average SAGD based on 2015 operating data to the MEG 2015 project reduces WTR GHG emissions intensity by 1.0 g CO_2eq/MJ dilbit (from 13.2 to 12.2 g CO_2eq/MJ) This helps to demonstrate industry leading operations, innovation, and favourable reservoirs for bitumen production. Previous work has investigated the drivers of upstream GHG emissions intensities for oil sands-derived crudes on a project basis (Sleep et al. 2018; Orellana et al. 2017). However, the pathways modelled in this study should not be considered as representative of industry averages or typical cases.

In addition to showing the performance of these above-average performing projects to oil sands bitumen production pathways characterized in Masnadi et al., we demonstrate the observed (MEG eMSAGP) and anticipated (Imperial SA-SAGD) GHG intensity reductions from the application of two emerging in situ bitumen production technologies. Compared to a SAGD project deployed in the same reservoir, MEG's eMSAGP and Imperial's SA-SAGD technologies are expected to reduce WTR GHG emissions intensities by 14 and 19%, respectively.

Based on the comparisons shown above, we find that, if the Alberta inputs used to adapt the OPGEE runs for the projects in this study are verified (particularly the upstream natural gas intensity), above-average performing oil sands projects could approach the global average WTR GHG emissions intensity estimated by Masnadi et al. (10.3 g CO2eq/MJ crude). A robust comparison of these oil sands projects to a global average GHG emissions intensity of crude production would require that the approach taken in this study to characterize the emissions from oil sands projects in the Alberta region be completed for all crude producing regions globally. This is outside of the scope of the current study. However, this study demonstrates the potential reduction in GHG intensities from emerging technologies compared to current projects and the impact of adopting regional emissions factors on WTR GHG intensity estimates of oil sands projects. The two emerging technologies modeled in this study (eMSAGP and SA-SAGD) can further reduce upstream GHG emissions intensities by 14 and 19% compared to a SAGD project deployed at the same reservoir. Changing the Masnadi et al. and OPGEE generic inputs and assumptions to Alberta-specific inputs reduce WTR GHG emissions intensities estimates by up to 35% (Imperial Kearl pathway). Further work is required to understand how other pathways from Masnadi et al. would be affected by similar adjustments of generic OPGEE inputs to account for regional differences. On a WTW basis, these reductions from the adoption of emerging technologies are approximately 1.6 and 1.9% of the full life cycle on a per MJ gasoline basis for eMSAGP and SA-SAGD, respectively.

While WTR comparisons provide an idea of how these projects perform, as crude compositions across oil fields vary, resulting in different downstream emissions from refining and combusting products derived from the crude, the full life cycle should be accounted for to fully understand differences in the GHG emissions intensity impacts of producing and processing these crudes.

3.9.2 Recommendations for future work

The Alberta government and companies participating in this study have provided unprecedented access to both public and confidential operating data and data to better characterize the regional context that allowed for a much more robust estimate than in other jurisdictions. This can and should be done for other jurisdictions, but current public data does not allow for such an assessment.

The Alberta specific data employed in this study represents the most detailed data available but still has uncertainty. For example, upstream GHG emissions intensities from western Canadian natural gas should be estimated in a more comprehensive manner than has been done in the public realm at the time of this study. The upstream natural gas emissions intensity number used in this study is a better representation of natural gas supplied to oil sands operators than the default employed in OPGEE (which is obtained from the GREET model) but still has uncertainty due to poor public data availability. Future work should attempt to reduce this uncertainty.

The two new technologies assessed in this study (eMSAGP and SA-SAGD) have the potential to reduce upstream SAGD emissions by 14 and 19%, respectively, if they perform as proposed by the companies themselves (as reported in operating performance reports and regulatory applications). The full life cycle should also be considered where these emissions reductions are 1.6 and 1.9% lower on a full life cycle basis (since 60 to 80% of the life cycle emissions come from combusting the transport fuels). Compared to the upstream model validation, similarly rich information was not provided in this study to investigate downstream activities and models. Future work should investigate the downstream components of the life cycle to comprehensively evaluate the impacts of these emerging technologies on a WTW basis.

The comparison to Masnadi et al. demonstrates the scale of impact that adopting an upstream natural gas emissions intensity estimate intended to reflect western Canadian gas production has on WTR GHG intensity estimates of oil sands pathways. As noted in Section 3.8.2 (Table 3-2), OPGEE employs a generic upstream natural gas emissions intensity factor (14.3 g CO_2eq/MJ LHV) obtained from the GREET1_2017 model (Wang 2017), who developed these emissions intensity factors based on the U.S. Environmental Protection Agency (EPA)'s annual GHG inventories (method described in Burnham et al. 2017). As such, this upstream emission factor for natural gas supply was developed based on U.S. data and is expected to be most representative of that region. In addition to being affected by the region from which natural gas is supplied, upstream emissions intensity estimates are both highly variable and uncertain. Recent literature (e.g., Brandt et al. 2014) has shown large discrepancies in fugitive emissions estimates for natural gas supply between top-down and bottom-up analyses, contributing to wide uncertainty ranges around natural gas extraction, processing, and transport emissions even from a single region when different modeling methods and assumptions are used to estimate the emissions intensity. Within the GREET model itself, the upstream natural gas emissions intensity estimate is updated annually, and has ranged from 15.1 g CO_2eq/MJ LHV in GREET1_2016 to 12.4 g CO_2eq/MJ LHV in GREET1_2019.

In this study, we employ an upstream natural gas emissions intensity estimate of 6.4 g CO_2eq/MJ (LHV) from Senobari (2016), intended to represent local natural gas supply in western Canada. Emissions intensity estimates for Canadian natural gas supply vary widely in the literature. GHGenius (v5.0e; (S&T)^2 2019) estimates the emissions intensity for Canadian natural gas supply to be 10.4 g CO_2eq/MJ (LHV). Previous upstream GHG intensity estimates in GHGenius for conventional western Canadian natural gas and shale gas from the Horn River and Montney formations have been 8.3, 13.3, and 6.8 g CO_2eq/MJ (LHV), respectively ((S&T)^2

2011). Sapkota et al. (2018) estimate that emissions from the recovery and processing of shale gas from western Canada's Horn River and Montney formations range from 5.9-11.5 g CO_2eq/MJ (they do not specify if on a lower or higher heating value basis). It is important to note that the rigor and transparency of the current western Canadian estimates are limited at the present time and that further work is needed to validate and support these estimates. Further, should a region-specific upstream natural gas emissions intensity be adopted for the oil sands in global crude GHG intensity estimates, region-specific upstream inputs should be employed for all oil producing regions as each region will have its own set of characteristics and upstream emissions intensities. For example, a study of natural gas supply across the European Union found national upstream natural gas emissions factors ranging from 3.1 g CO_2eq/MJ (Denmark) to 15.3 g CO_2eq/MJ (Spain; European Commission 2015). At present, limited data exists in the public realm to model upstream natural gas supply chain emissions for each crude producing region in a consistent and transparent way. An important outcome of this study is that we identify through this work the importance of regional variability in natural gas upstream emissions on WTR emissions intensities of crude production. Future work should improve upon these estimates

While it was out of scope to provide detailed comparison to other studies, it is recommended that a similar method of comparison be undertaken to provide further insights about the emissions intensities of these pathways as well as the impacts of different model assumptions and data (i.e., IHS Markit, 2019; Gordon et al. 2015).

4 Discussion

Existing oil sands technologies and projects have been well characterized in the public literature and open source tools are available to estimate their relative GHG emissions intensities. However, these models can be further improved through evaluation and comparison with industry operating data. In addition, LC GHG emissions intensities estimates of emerging technologies can be assessed within the framework provided in these tools with the addition of new functionality and data from operating pilots, etc. This project conducts LCAs of five oil sands pathways.

The GHG emissions intensities of three existing oil sands projects are estimated in this project: 1) CNRL's Horizon mining project (pathway: surface mining (naphthenic froth treatment) + upgrading + refining, modeled); 2) Imperial's Kearl mining project (pathway: surface mining (paraffinic froth treatment) + dilution + refining; and 3) MEG's Christina Lake Regional Project (CLRP) Steam Assisted Gravity Drainage (SAGD) project (pathway: SAGD + dilution + refining. The life cycle GHG emissions intensities of two new emerging oil sands projects are also estimated in this project: 1) the enhanced Modified Steam And Gas Push (eMSAGP) technology developed by MEG Energy; and 2) the Solvent-Assisted SAGD (SA-SAGD) technology developed by Imperial.

This analysis shows that when project specific input data and boundaries are aligned, the open source upstream tool (OPGEE) generates GHG emissions estimates that are within 1-4% of company reported data. When the boundary is expanded to reflect the set of activities typically considered in LC studies (i.e., expanding the boundary from direct emissions included in company reported data to also include indirect emissions from natural gas production, electricity and diluent supply, lifetime land use and lifetime tailings ponds emissions), upstream GHG emissions Intensities for current oil sands pathways (extraction to refinery entrance gate) can increase by almost 100% (from 25.7, 70.6, and 37.9 kg CO_2eq/bbl crude to 54.7, 93.9, and 55.7 kg CO_2eq/bbl crude for Imperial Kearl, CNRL Horizon, and MEG eMSAGP pathways, respectively). Note that each pathway produces a crude with unique properties that will have distinct downstream emissions, particularly the CNRL Horizon pathway which produces synthetic crude oil (SCO) while other pathways produce dilbit. While no evaluation of downstream activities (refining and combustion of fuels) was conducted in this project, their inclusion helps to demonstrate that emissions from upstream oil sands operations contribute between 9.6-17% of the LC emissions (507, 552, and 507 kg CO_2eq/bbl crude for Imperial Kearl, CNRL Horizon, and MEG SAGD pathways, respectively). The exercise of comparing model estimates to publicly reported data demonstrates the need for careful treatment, understanding, and interpretation of publicly reported data for use in life cycle assessment models. It also emphasizes the need for complete and transparent statements about boundaries (what activities are and are not included) in all studies and public reporting of project emissions. Regional regulatory reporting requirements may utilize boundaries that differ from LCA studies so are not always aligned with the data input needs and boundary choices when life cycle estimates are the goal.

The two mining pathways in this study are estimated to have achieved short-term upstream (bitumen production, extraction, and dilution/upgrading, not full life cycle or WTW) GHG intensity reductions for dilbit/SCO production of 6.0% (Imperial Kearl pathway) and 14% (CNRL Horizon pathway), assessed by comparing 2015-2017 emissions to 2018 current (anticipated steady state) emissions. The two emerging oil sands pathways show that there may be a potential to reduce extraction emissions if these technologies are deployed. eMSAGP shows that there is potential to reduce upstream emissions by approximately 14% below SAGD on the same reservoir and SA-SAGD has the potential to reduce upstream emissions by approximately 19% below SAGD on the same reservoir. These reductions are somewhat muted when placed on a full WTW basis (as 83-90% of LC emissions occur downstream of the extraction facilities). Over the WTW, on the same reservoir eMSAGP and SA-SAGD reduce emissions by approximately 1.6 and 1.9%, respectively. Scaling these estimates from intensity estimates based on operating data (eMSAGP) and regulatory application data (SA-SAGD) introduces additional uncertainties. However, to provide some context, the annual emissions reductions through deployment of these technologies at the scale proposed by these companies could be on the order of 0.58 million and one million tonnes of CO_2eq for MEG's Christina Lake and Imperial's Aspen projects, respectively, compared to SAGD deployed at that project under the same conditions.

New emerging in situ technologies may achieve additional reductions in upstream GHG emissions intensities. A current project by COSIA has shown reductions in land footprints at in situ sites over the 2012-2017 period of 6.9% which may lead to similar reductions in life cycle land use emissions for in situ projects (COSIA 2019). Better data may soon be available (e.g., improved data on land use and fugitive emissions through continuous monitoring at oil sands sites) that may reduce both the absolute GHG intensity as well as the uncertainty associated with the emissions estimates for those parameters. As such, the GHG emissions intensity estimates and near-term emissions intensity reductions presented in this study are not intended to be representative of future emissions intensity reductions, but rather show how these technologies perform (or are expected to perform in the case of SA-SAGD) and for existing technologies, how that performance has changed over the 2015-2018 operating period.

While every effort was made to model emissions for these technologies as accurately as possible, uncertainty and variability exist and should be considered when conducting LCAs. For example, sources of uncertainty include how new technologies will perform at large scale at reservoirs different from their current or proposed project sites. LCA models will also continue to have uncertainty and variability in characterizing outcomes of deploying technology to other reservoirs, processing the resulting crudes in different refinery configurations, producing different final product slates, etc. Specific sources of uncertainty in this study that merit future investigation include fugitive and land use change emissions estimates and diluent sourcing.

Several changes were made to the default settings in OPGEE as part of the customized runs to better reflect the specific projects and regional conditions of this study. These include modification of OPGEE inputs to better reflect Alberta context (rather than generic defaults employed in OPGEE, generally derived from the U.S. Department of Energy's Argonne National Laboratory's GREET model), modification of OPGEE inputs to better reflect the specific projects evaluated in this study by evaluating OPGEE's inputs relative to actual operating data, and the addition of emerging technology pathways to OPGEE that were not previously available in the model.

The accuracy and representativeness of the OPGEE model in characterizing upstream emissions from oil sands pathways generally was also improved through this comparison exercise. This includes 1) redesigning the steam generation module to allow more detailed calculations and more heat recovery potential via air pre-heaters, economizers, and blowdown water heat recovery, as well as to better characterize cogeneration units, 2) more detailed modelling of available blowdown water treatment to allow the user to input a blowdown water treatment recycling rate, 3) addition of more water treatment technologies, and 4) additional methods for modelling heavy oil dilution. These modifications have been or are proposed for incorporation into OPGEE 3.0.

Each study that has previously estimated life cycle GHG emissions intensities from fuels produced from oil sands-derived crudes is distinct in terms of its goal, scope, boundaries, data employed, projects or pathways characterized, modelling approaches used, and assumptions made throughout the study. Without some alignment of boundaries, assumptions, etc., no two studies can be directly compared (not an apples-to-apples comparison). This study presents results based on data reflective of steady state operations for five oil sands projects and use of data that best reflects the Alberta context. While we have used the same open-source tool (e.g., OPGEE) employed in other life cycle studies of petroleum-derived crudes (e.g., Masnadi et al.

2018; Gordon et al. 2015), several changes were made to the model to both adapt the model to represent the Alberta context and to generate (in consultation with companies), the most accurate representation of their specific project operations using data available at the time of the study.

We find that, if the Alberta inputs used to adapt the OPGEE runs for the projects in this study are verified (particularly the upstream natural gas intensity), above-average performing oil sands projects could approach the global average WTR GHG emissions intensity estimated by Masnadi et al. (10.3 g CO2eq/MJ crude). A robust comparison of these oil sands projects to a global average GHG emissions intensity of crude production would require that the approach taken in this study to characterize the emissions from oil sands projects in the Alberta region be completed for all crude producing regions globally. This is outside of the scope of the current study. However, this study demonstrates the potential reduction in GHG intensities from emerging technologies compared to current projects and the impact of adopting regional emissions factors on WTR GHG intensity estimates of oil sands projects. The two emerging technologies modeled in this study (eMSAGP and SA-SAGD) can further reduce upstream GHG emissions intensities by 14 and 19% compared to a SAGD project deployed at the same reservoir. Changing the Masnadi et al. and OPGEE generic inputs and assumptions to Alberta-specific inputs reduce WTR GHG emissions intensities estimates by up to 35% (Imperial Kearl pathway). Further work is required to understand how other pathways from Masnadi et al. would be affected by similar adjustments of generic OPGEE inputs to account for regional differences. On a WTW basis, these reductions from the adoption of emerging technologies are approximately 1.6 and 1.9% of the full life cycle on a per MJ gasoline basis for eMSAGP and SA-SAGD, respectively.

The Alberta government and companies participating in this study have provided unprecedented access to both public and confidential operating data and data to better characterize the regional context that allowed for a much more robust estimate than in other jurisdictions. This can and should be done for other jurisdictions, but current public data does not allow for such an assessment.

Appendices

A. Additional data

A.1. Additional background on fugitive and land use emissions data sources

Table A-1. Assumptions for the Base GHG model to estimate tailings ponds emissions proposed by Burkus et al. (2014)

Parameter	Paraffinic (P)	Naphtha (N8) light	Naphtha (N10) heavy
Empirical formula of proxy molecule	C_6H_{14}	C_8H_{18}	$C_{10}H_{22}$
Molar mass (approximate)	86	114	142
Carbon %	83.72	84.21	84.51
Density, Kg/m^3 (SG_{dil})	655	703	(730*) 780
Volatilized (1 - VF_{VOC})	40%	35%	30%
Aerobic fermentation in pond (1 - AnF)	10%	10%	10%
Loss to other fermentations (1 - SRBF)	10%	10%	10%
CO_2 : CH_4 molar ratio	1.25 : 4.75	1.75 : 6.25	2.25 : 7.75
Methane from theoretical maximum (MEF)	90%	90%	90%

* density of pure n-decane

Source: Burkus et al. (2014)

Table A-2. Base GHG model results for tailings ponds emissions from Burkus et al. (2014).

Step	Parameter and unit	Multiplier factor	Diluent: Paraffinic (P)	Diluent: Naphtha (N8) light	Diluent: Naphtha (N10) heavy
	Proxy molecule →		C_6H_{14}	C_8H_{18}	$C_{10}H_{22}$
1	1 barrel of bitumen, L		159	159	159
2	Diluent loss to tailings, DVLF	0.004	0.004	0.004	0.004
3	Volume of diluent lost, L		0.636	0.636	0.636
4	Density, g/L	variable	685[1]	703	780*
5	Weight of diluent lost, g		435.66	447.108	496.08
6	Carbon mass ratio in diluent	variable	72/86	96/114	120/142
7	Carbon weight in lost dil. g		**364.74**	**376.51**	**419.22**
8	VF_{voc} – volatility factor	variable	0.6	0.65	0.7
9	Carbon left in pond , g		**218.84**	**244.73**	**293.46**
10	AnF (anaerobic-aerobic split)	0.9	0.9	0.9	0.9
11	Carbon for anaerobic processes, g		196.96	220.26	264.11
12	SRBF (10% loss to other fermentations)	0.9	0.9	0.9	0.9
13	Carbon in methanogenesis, g		**177.26**	**198.23**	**237.70**
14	CH_4 molar part of carbon	variable	4.75 : 6	6.25 : 8	7.75 : 10
15	Carbon available for methane, g		140.33	154.87	184.22
16	MEF – methane efficiency	0.9	0.9	0.9	0.9
17	Carbon emitted as methane, g		**126.30**	**139.38**	**165.80**
18	CO_2eq factors	16/12 x 25	16/12 x 25	16/12 x 25	16/12 x 25
19	Methane CO_2eq, g/bbl		4,210.0	4,646.1	5,526.5
20	Factor per MJ energy	1/6,100	1/6,100	1/6,100	1/6,100
21	**Methane CO_2 eq/MJ, g**		**0.69**	**0.76**	**0.91**
22	Carbon available for CO_2, g (step 9 minus step 17)		**92.54**	**105.35**	**127.66**
23	Carbon to carbon dioxide	44/12	44/12	44/12	44/12
24	CO_2 (from step 22), g		339.3	386.3	468.1
25	Factor per MJ energy	1/6,100	1/6,100	1/6,100	1/6,100
26	**CO_2/MJ (from step 24)**		**0.056**	**0.063**	**0.077**
27	**Total pond GHG emissions intensity CO_2eq/MJ, g**		**0.75**	**0.83**	**0.98**

* Heavy naphtha – assumed heavier than pure decane whose density is 730 g/L
[1] Real density on Shell site is 0.645 to 0.655 meaning it is a mix of pentane and hexane
Multiplication factors are in red; values in bold are: **Black** – mass of carbon, **Green** – methane GHG intensity, **Brown** – CO_2 intensity, **Blue** – Total GHG intensity

Source: Burkus et al. (2014).

Table A-3. Lifetime land use change emissions estimates from Yeh et al. (2015) for mining and in situ projects operating in 2009.

	Total C emissions to date, 2009 (Mt C)		*Average Land use CI (tC/ha)*		*Estimated total C emissions from the entire lifetime of the project (Mt C)*		*Estimated LU CI from the entire lifetime of the project (gCO_2e/MJ)*	
Surface mining								
	Low	High	Low	High	Low	High	Low	High
Suncor-MSV mines	8.7	8.8	698	706	16.4	16.6	2.42	2.45
Syncrude (Mildred Lake	6.5	6.6	453	461				
and Aurora North)					10.5	10.7	0.80	0.82
Mildred Lake	3.0	3.1	318	327	-	-		
Aurora North Mine	3.5	3.5	704	711	-	-		
Muskeg and expansion	3.5	3.5	719	727	13.7	13.8	2.98	3.01
Horizon	1.9	2.0	411	419	15.2	15.5	2.87	2.92
Total	*20.6*	*20.9*	*515*	*523*	55.8	56.6	1.87	1.90
In-situ								
Surmont	0.18	0.28	55	88	0.26	0.41	1.57	2.49
Christina Lake	33	55	68	114	0.16	0.27	0.56	0.94
Mackay River	13	19	52	74	0.05	0.07	0.21	0.30
Long Lake	147	225	47	71	0.26	0.39	0.82	1.26
Firebag	56	88	56	89	0.14	0.21	0.13	0.20
Jackfish	34	57	71	118	0.18	0.30	0.60	0.99
Christina Lake Regional	30	49	66	105	0.25	0.39	2.12	3.39
Total	*0.49*	*0.77*	*57*	*87*	*1.3*	*2.1*	0.56	0.89

Source: Yeh et al. (2015)

A.2. Crude assays

Crude assays employed in modelling refinery emissions from each pathway are shown in Table A-4 to Table A-8 below.

Table A-4. Crude assay, Imperial Kearl dilbit

Assay #		**Cutoff Temp [°C]**	**80**	**180**	**290**	**340**	**400**	**450**	**525**	**525 +**	**400 +**
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	100,086	8,919	12,957	12,158	4,697	6,442	5,633	9,820	39,461	54,530
Vol Flow	m^3/d	15,913.75	1,418	2,060	1,933	747	1,024	896	1,561	6,274	8,670
Mass Flow	kg/d	14,641,612	846,973	1,444,115	1,673,139	687,748	965,118	862,013	1,546,321	6,616,186	9,024,520
Sulfur	wt%	4.17	0.00	0.17	1.21	2.06	2.66	3.34	4.21	6.86	6.07
Nitrogen	mass ppm	4184.02	7.2	0.8	32.7	269.8	807.8	1550.0	2780.8	8252.11	6674.4
API gravity	°API	22.0	105.1	70.16	31.82	22.02	18.53	15.38	11.24	2.55	4.31

Density	kg/m³	920.86	597.2	701.0	865.53	920.8	942.2	962.4	990.4	1054.5	1040.9
Hydrogen	wt%	11.78	18.99	15.81	12.16	11.51	11.36	11.21	10.94	10.23	10.45
MCR	wt%	8.42								18.45	13.66
Char Factor	Kw (approx)	12.09	14.00	12.80	11.23	11.07	11.14	11.20	11.22	11.23	11.23
Tb(50%) weight basis	°C	495.17	53	129	238	318	370	425	492	653	616

Temp: temperature; LSR: light straight run; AGO: atmospheric gas oil; LVGO: light vacuum gas oil; HVGO: heavy vacuum gas oil; VR: vacuum residue; AR: atmospheric residue; Vol: volume; bpd: barrel per day; wt%: percentage on a weight basis; ppm: parts per million; API: American Petroleum Institute; MCR: micro carbon residue. Char: Characterization; Kw: Watson characterization factor approx: approximate

Table A-5. Crude assay, CNRL Horizon pathway SCO

Assay #		**Cutoff Temp [°C]**	**80**	**180**	**290**	**340**	**400**	**450**	**525**	**525 +**	**400 +**
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,792	491	21,667	41,884	13,353	12,303	5,819	3,696	579	10,087
Vol Flow	m³/d	15,866.87	78	3,445	6,660	2,123	1,956	925	588	92	1,604
Mass Flow	kg/d	13,500,114	53,637	2,608,973	5,683,879	1,891,524	1,776,798	853,510	546,481	85,312	1,485,303
Sulfur	wt%	0.05	0.01	0.00	0.02	0.06	0.10	0.16	0.23	0.13	0.19
Nitrogen	mass ppm	173.90	11.1	1.7	41.9	156.4	353.0	662.7	1050.5	492.75	795.6
API gravity	°API	35.0	74.37	55.16	34.13	27.17	24.13	21.73	20.52	21.13	21.14
Density	kg/m³	849.06	686.7	757.3	853.5	890.9	908.31	922.5	929.9	926.2	926.11
Hydrogen	wt%	12.63	15.48	14.15	12.45	12.12	12.01	11.95	11.99	11.70	11.95
MCR	wt%	0.01								1.57	0.09
Char Factor	Kw (approx)	11.62	12.45	12.01	11.39	11.44	11.53	11.67	11.87	12.29	11.73
Tb(50%) weight basis	°C	262.40	75	146	238	316	366	421	477	549	441

Temp: temperature; LSR: light straight run; AGO: atmospheric gas oil; LVGO: light vacuum gas oil; HVGO: heavy vacuum gas oil; VR: vacuum residue; AR: atmospheric residue; Vol: volume; bpd: barrel per day; wt%: percentage on a weight basis; ppm: parts per million; API: American Petroleum Institute; MCR: micro carbon residue. Char: Characterization; Kw: Watson characterization factor approx: approximate

Table A-6. Crude assay, MEG SAGD and eMSAGP pathways

Assay #		**Cutoff Temp [°C]**	**80**	**180**	**290**	**340**	**400**	**450**	**525**	**525 +**	**400 +**

Property	Units	Full Crude	LSR	Naphtha	Kerosene	Diesel	AGO	LVGO	HVGO	VR	AR
Vol Flow	bpd	99,851	10,874	14,179	12,409	4,600	6,171	5,278	8,951	37,389	51,192
Vol Flow	m³/d	15,876.32	1,729	2,254	1,973	731	981	839	1,423	5,945	8,140
Mass Flow	kg/d	14,581,769	1,055,724	1,586,096	1,681,614	665,812	916,665	804,132	1,412,600	6,459,126	8,675,858
Sulfur	wt%	4.20	0.00	0.14	1.03	1.82	2.43	3.13	4.08	7.36	6.43
Nitrogen	mass ppm	4062.08	10.6	0.7	41.8	276.3	781.8	1481.4	2641.0	8256.09	6713.9
API gravity	°API	22.6	100.00	69.43	34.35	23.80	19.81	16.02	10.93	-1.39	1.12
Density	kg/m³	917.09	610.62	703.54	852.32	910.24	934.27	958.27	992.52	1086.50	1065.88
Hydrogen	wt%	11.74	18.34	15.70	12.47	11.72	11.51	11.29	10.90	9.78	10.10
MCR	wt%	10.55								23.58	17.73
Char Factor	Kw (approx)	12.08	13.70	12.74	11.40	11.20	11.23	11.25	11.20	10.94	11.01
Tb(50%) weight basis	°C	484.22	53	128	237	318	370	425	491	663	626

Temp: temperature; LSR: light straight run; AGO: atmospheric gas oil; LVGO: light vacuum gas oil; HVGO: heavy vacuum gas oil; VR: vacuum residue; AR: atmospheric residue; Vol: volume; bpd: barrel per day; wt%: percentage on a weight basis; ppm: parts per million; API: American Petroleum Institute; MCR: micro carbon residue. Char: Characterization; Kw: Watson characterization factor approx: approximate

Table A-7. Crude assay, Imperial SA-SAGD pathway

Assay #		Cutoff Temp [°C]	80	180	290	340	400	450	525	525 +	400 +
Property	Units	Full Crude	LSR	Naphtha	Kerosene	Diesel	AGO	LVGO	HVGO	VR	AR
Vol Flow	bpd	107,323.07	6,132.38	7,079.96	10,479.59	4,806.34	7,061.35	6,470.46	11,486.68	53,806.31	71,645.59
Vol Flow	m³/d	17,064.37	974.97	1,125.62	1,666.12	764.15	1,122.66	1,028.72	1,826.24	8,554.52	11,390.74
Mass Flow	kg/d	14,933,847.00	922,200.22	1,077,510.73	1,591,668.40	726,763.34	1,058,240.17	956,869.62	1,662,768.05	6,937,826.46	9,557,464.13
Sulfur	wt%	4.03	0.01	0.51	1.35	2.05	2.65	3.23	3.89	6.30	5.57
Nitrogen	mass ppm	3,873.14	3.32	7.26	50.17	259.57	743.93	1,452.63	2,477.05	7,389.28	5,940.31
API gravity	°API	19.01	17.96	16.19	16.49	17.15	18.48	20.49	23.77	42.82	36.99
Density	kg/m³	939.31	945.87	957.26	955.31	951.08	942.61	930.16	910.49	811.01	839.06
Hydrogen	wt%	12.55	6.25	8.87	10.27	10.91	11.35	11.81	12.40	14.98	14.21
MCR	wt%	10.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.08	16.93
Char Factor	Kw (approx)	11.89	8.59	9.40	10.19	10.72	11.13	11.59	12.20	14.75	13.99
Tb(50%)	°C	504.07	26.23	133.16	240.89	317.95	370.71	425.43	490.93	679.72	626.58

weight basis

This assay was generated by blending the Cold Lake_Crude Monitor_Old assay with the ColdLake_Thermal_Alberta.ca assay in PRELIM's assay inventory (0.85 and 0.15 by mass ratio, respectively). Temp: temperature; LSR: light straight run; AGO: atmospheric gas oil; LVGO: light vacuum gas oil; HVGO: heavy vacuum gas oil; VR: vacuum residue; AR: atmospheric residue; Vol: volume; bpd: barrel per day; wt%: percentage on a weight basis; ppm: parts per million; API: American Petroleum Institute; MCR: micro carbon residue. Char: Characterization; Kw: Watson characterization factor approx: approximate.

Table A-8. PADD2 blended crude oil assay

Assay #		**Cutoff Temp [°C]**	**80**	**180**	**290**	**340**	**400**	**450**	**525**	**525 +**	**400 +**
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,200	-	122	4,902	5,001	9,828	10,827	21,137	49,383	81,663
Vol Flow	m^3/d	16,090.88	-	19	779	795	1,563	1,722	3,361	7,852	12,984
Mass Flow	kg/d	16,066,004	-	16,752	692,345	727,024	1,481,280	1,677,689	3,323,226	8,147,687	13,148,602
Sulfur	wt%	4.33	1.14	0.98	1.43	2.12	3.06	3.63	3.98	5.29	4.75
Nitrogen	mass ppm	3406.85	81.1	25.3	61.4	216.5	714.4	1470.6	2538.1	5225.31	4067.0
API gravity	°API	8.4	32.21	31.94	27.65	23.11	17.63	13.55	11.46	4.73	8.10
Density	kg/m^3	1010.44	863.47	864.89	888.20	914.32	947.93	974.54	988.81	1037.68	1012.65
Hydrogen	wt%	10.90	11.08	11.50	11.83	11.65	11.26	11.00	10.97	10.64	10.77
MCR	wt%	13.28								25.92	16.23
Char Factor	Kw (95pprox.)	11.19	10.46	10.72	11.11	11.17	11.08	11.07	11.24	11.29	11.31
Tb(50%) weight basis	°C	532.57	137	171	262	320	373	426	492	623	565

Temp: temperature; LSR: light straight run; AGO: atmospheric gas oil; LVGO: light vacuum gas oil; HVGO: heavy vacuum gas oil; VR: vacuum residue; AR: atmospheric residue; Vol: volume; bpd: barrel per day; wt%: percentage on a weight basis; ppm: parts per million; API: American Petroleum Institute; MCR: micro carbon residue. Char: Characterization; Kw: Watson characterization factor approx: approximate. Source: Cooney et al. 2017 (pg Si-38).

A.3. PADD2-average crude upstream and crude transport emissions

Data from Cooney et al. (2017) is employed to estimate the emissions associated with producing and transporting an average barrel of crude refined in PADD2. Extraction and transport emissions for each crude are estimated in Cooney et al. using OPGEE. A PADD-average emissions intensity in g CO_2eq/kg crude is calculated using the data provided in Cooney et al. Tables SI-11 and SI-36 (see Table A-9). For this study, emissions are converted to kg CO_2eq/bbl crude employing the PADD2 average crude density of 138.6 kg CO_2eq/bbl (see Table A-8).

Table A-9. Rebuild of PADD2-average upstream and crude transport emissions based on crude mix refined in PADD2 in 2014

Country	PRELIM Crude	OPGEE Crude	Contributions to PADD2 refinery mix (mass %)[1]	Extraction and transport GHG (g CO2eq/kg crude)[2]	Contribution to PADD2 GHG (g CO2eq/kg crude)
Canada	Cold Lake_Crude Monitor	Bitumen	19.8%	526	103.8
Canada	Albian Residual Blend_Crude Monitor	Canada Average (Conventional)	1.5%	355	5.3
Canada	Bow River North_Crude Monitor	Canada Average (Conventional)	1.9%	355	6.8
Canada	Lloyd Blend_Crude Monitor	Canada Average (Conventional)	1.9%	355	6.6
Canada	Lloyd Kerrobert_Crude Monitor	Canada Average (Conventional)	1.7%	355	6.2
Canada	Seal Heavy_Crude Monitor	Canada Average (Conventional)	1.8%	355	6.4
Canada	Smiley-Coleville_Crude Monitor	Canada Average (Conventional)	1.4%	355	5.1
Canada	Wabasca Heavy_Crude Monitor	Canada Average (Conventional)	1.9%	355	6.7
Canada	Western Canadian Blend_Crude Monitor	Canada Average (Conventional)	1.8%	355	6.2
Canada	Western Canadian Select_Crude Monitor	Canada Average (Conventional)	1.7%	355	6.1
Canada	Lloyd minister Statiev	Canada Average (Conventional)	1.8%	355	6.2
Canada	Hibernia_Exxon	Canada-Hibernia	1.7%	231	4.0
Canada	Hibernia_Statoil	Canada-Hibernia	1.8%	231	4.2
Canada	Hibernia_Chevron	Canada-Hibernia	1.4%	231	3.1
Canada	High Sour Edmonton_Crude Monitor	Canada-Hibernia	1.8%	231	4.2
Canada	Midale_Crude Monitor	Canada-Midale (Southeast Saskatchewan)	3.0%	480	14.2
Canada	Husky Synthetic Blend_Crude Monitor	SynCrude	4.7%	1086	50.9
Canada	Suncor Synthetic A_Crude Monitor	SynCrude	4.8%	1086	52.3
Canada	Suncor Synthetic H_Crude Monitor	SynCrude	0.2%	1086	1.7
Canada	Syncrude Synthetic_Crude Monitor	SynCrude	4.3%	1086	47.1

U.S.	Mars_BP	US-PADD3 - GOM Offshore	0.1%	215	0.3
U.S.	Bakken	US-Bakken-PADD2	6.1%	444	26.9
U.S.	West Texas intermediate	US-PADD3 - Texas	24.7%	253	62.5
U.S.	West Texas Sour	US-PADD3 - Texas	0.1%	253	0.2
U.S.	PADD1 Estimate	US-PADD1 - All	0.3%	289	0.9
U.S.	PADD4 Estimate	US-PADD4 - All	8.0%	318	25.5
TOTAL	**N/A**	**N/A**	**100%**	**N/A**	**463**

[1]Source: Cooney et al. (2017) Supporting Information Table SI-11. [2]Source: Cooney et al. (2017) Supporting Information Table SI-26.

A.4 Additional background on refined products transport distances

PADD 2 capacity: **3,922,200 bbl/day –** assuming a yield of 87% → **3,415,314**
Assume: Minneapolis to Chicago as average distance inside PADD 2- 400-450 miles

Outbound shipments from PADD 2 averaged **158,000 b/d** in 2015 – only 5% of total production

- Approximately 83,000 b/d moved from PADD 2 to PADD 4 primarily via Magellan's Chase Pipeline from Kansas refineries to the Denver area
  - 530 miles HollyFrontier El Dorado Refining to Denver
  - 650 miles Coffeyville Resources LLC to Denver
  - 470 miles CHS Refinery at McPherson KS to Denver
  - 400 miles from Oklahoma Panhandle in PADD 2 to Denver
- Meanwhile, 48,000 b/d moved from PADD 2 to PADD 3 on Magellan pipelines from Oklahoma and Kansas refineries to Arkansas
  - 450 miles
  - 350 miles
  - 520 miles
  - Oklahoma to Arkansas 450 miles
- 27,000 b/d moved from PADD 2 to PADD 1 on Buckeye, Sunoco, and Marathon pipelines from Ohio refineries into the Pittsburgh market in western Pennsylvania.
  - Ohio to Pittsburgh 200 miles

(U.S. EIA 2017)

B. Detailed list of OPGEE inputs for each oil sands pathway

Table B-1 through Table B-4 show the detailed OPGEE input parameters employed in modelling each oil sands pathway.

Table B-1. List of input parameters used in OPGEE to model Imperial Kearl pathway

Parameter			Unit	Value (2015-2017)	Value (2018)	Reference
In	p	Production methods	Downhole pump		0	0	
			Water reinjection		0	0	

	Natural gas reinjection		0	0	
	Water flooding		0	0	
	Gas lifting		0	0	
	Gas flooding		0	0	
	Steam flooding		0	0	
	Oil sands mine (integrated with upgrader)		0	0	
	Oil sands mine (non-integrated with upgrader)		1	1	
Field properties	Field location (Country)		Canada	Canada	
	Field name		Kearl	Kearl	
	Field age	yr	6	6	
	Field depth	ft	0	0	
	Oil production volume	bbl/d	170,231	208,865	Bitumen leaving facility reported to AER ST39 ("bitumen deliveries")
	Number of producing wells		0	0	
	Number of water injecting wells		0	0	
	Production tubing diameter	in	0	0	
	Productivity index	bbl/psi-d	0	0	
	Reservoir pressure	psi	0	0	
	Reservoir temperature	˚F	0	0	
	Offshore?		0	0	
Fluid properties	API gravity	deg.API	8.4	8.4	Athabasca mining bitumen assay from Alberta's Bitumen Assay Program (Alberta Government 2019)
Production practices	Fraction electricity generated on-site		0.30	0.30	Calculated from electricity production and plant use data in AER ST39. Linked to "bitumen mining" worksheet.
Processing practices	Upgrader type	0 = none 1 = delayed coking	0	0	
	Flaring-oil-ratio	scf/bbl crude	17.9	18.6	Calculated from flaring data in AER ST39. Linked to "bitumen mining" worksheet.
	Venting-oil-ratio	scf/bbl crude			
	Volume fraction of diluent		0.25	0.28	Calculated from volumes of bitumen and diluent leaving facility in AER ST39 (reported as "bitumen deliveries")
Crude oil transport	Fraction oil transported by each mode				
	Ocean tanker		0		
	Barge		0		
	Pipeline		1		
	Rail		0		
	Truck		0		

		Transport distance (one way)	mile			
		Ocean tanker		0		
		Barge		0		
		Pipeline		1553		2,500 km assumed distance from oil sands facilities to PADD2
		Rail		0		
		Truck		0		
	Small sources emissions		g CO_2eq/MJ crude	0	0	Assumed not applicable to oil sands mining pathways as all fuel consumption on-site is reported to either AER ST39 or SGER. Emissions from these sources are all explicitly estimated in this study.
Bitumen mining worksheet	Mining energy intensity input table	Diesel fuel use	gal diesel/bbl bitumen	0.55	0.53	Annual volume of diesel consumed reported in SGER reports. Obtained from Imperial upon request.
		Natural gas use	scf/bbl bitumen	551.0	479.2	Natural gas consumption data reported in AER ST39 ("natural gas fuel use")
		Electricity use	kWh/bbl bitumen	18.6	18.4	Electricity use data reported in AER ST39 ("electricity plant use")
		Electricity gen.	kWh/bbl bitumen	5.4	6.1	Electricity generation data reported in AER ST39 ("electricity generation")
		Net electricity imported	kWh/bbl bitumen	13.2	12.3	Calculated from electricity production and plant use data in AER ST39.
		Fraction electricity generated on-site		0.3	0.3	Calculated from electricity production and plant use data in AER ST39. Linked to "inputs" worksheet.
		Gasoline use	gal diesel/bbl bitumen	0.022	0.025	Annual volume of gasoline consumed reported in SGER reports. Obtained from Imperial upon request.
		Flaring-oil-ratio	scf/bbl bitumen	17.9	18.6	Calculated from flaring data in AER ST39. Linked to "inputs" worksheet.
Heavy oil dilution	Heavy oil or bitumen dilution	Stream heating values				
		Heavy oil heating value	mmbtu/bbl			
		Bitumen heating value	mmbtu/bbl bitumen	6.1	6.1	
		Diluent heating value	mmbtu/bbl diluent			Calculated from diluent heating value required to meet dilbit API gravity 22º given vol. fraction of diluent
		Volume fraction of bitumen or heavy crude in dilbit		0.25	0.28	Calculated from volumes of bitumen and diluent leaving facility in AER ST39 (reported as "bitumen deliveries")
		Dilbit heating value	mmbtu/bbl dilbit	5.72	5.72	From "Fuel Specs" worksheet for API 22º dilbit
		API dilbit	deg API	22	22	Imperial Kearl crude assay (from PRELIM assay inventory)

Table B-2. List of input parameters used in OPGEE to model CNRL Horizon pathway (base case inputs)

		Parameter	Unit	Value (2015-2017)	Value (2018)	Reference
Inputs worksheet	Production methods	Downhole pump		0	0	
		Water reinjection		0	0	
		Natural gas reinjection		0	0	
		Water flooding		0	0	
		Gas lifting		0	0	
		Gas flooding		0	0	
		Steam flooding		0	0	
		Oil sands mine (integrated with upgrader)		1	1	
		Oil sands mine (non-integrated with upgrader)		0	0	
	Field properties	Field location (Country)		Canada	Canada	
		Field name		Horizon	Horizon	
		Field age	yr	10	10	
		Field depth	ft	0	0	
		Oil production volume	bbl/d			SCO leaving facility reported to AER ST39 ("SCO deliveries")
		Number of producing wells		0	0	
		Number of water injecting wells		0	0	
		Production tubing diameter	in	0	0	
		Productivity index	bbl/psi-d	0	0	
		Reservoir pressure	psi	0	0	
		Reservoir temperature	˚F	0	0	
		Offshore?		0	0	
	Fluid properties	API gravity	deg.API	35.0	35.0	Athabasca mining bitumen assay from Alberta's Bitumen Assay Program (Alberta Government 2019)
	Production practices	Fraction electricity generated on-site		0.66	0.66	Calculated from electricity production and plant use data in AER ST39. Linked to "bitumen mining" worksheet.
	Processing practices	Upgrader type	0 = none 1 = delayed coking	1	1	
		Flaring-oil-ratio	scf/bbl crude	0	0	All flaring data reported to AER ST39 allocated to upgrading
		Venting-oil-ratio	scf/bbl crude	0	0	
		Volume fraction of diluent		0	0	
	Crude oil transport	Fraction oil transported by each mode				
		Ocean tanker		0	0	
		Barge		0	0	
		Pipeline		1	1	
		Rail		0	0	
		Truck		0	0	

		Transport distance (one way)	mile			
		Ocean tanker		0	0	
		Barge		0	0	
		Pipeline		1553	1553	2,500 km assumed distance from oil sands facilities to PADD2
		Rail		0	0	
		Truck		0	0	
	Small sources emissions		g CO_2eq/MJ crude	0	0	Assumed not applicable to oil sands mining pathways as all fuel consumption on-site is reported to either AER ST39 or SGER. Emissions from these sources are all explicitly estimated in this study.
Bitumen mining worksheet	Mining energy intensity input table	Diesel fuel use	gal diesel/bbl bitumen	0.76	0.54	Annual volume of diesel consumed reported in SGER reports. Obtained from CNRL upon request.
		Fraction diesel produced on-site from upgrader	%	0.55	0.93	Volume of diesel consumed from SGER reports. Volume diesel produced and consumed on-site from AER ST39 (“SCO fuel use”)
		Process gas use	scf/bbl bitumen	97.1	68.5	Process gas consumption data reported in AER ST39; allocated to mining and upgrading based on data provided by CNRL
		Natural gas use	scf/bbl bitumen	58.2	61.6	Natural gas consumption data reported in AER ST39; allocated to mining and upgrading based on data provided by CNRL
		Electricity use	kWh/bbl bitumen	11.5	6.0	Electricity use data reported in AER ST39 (“electricity plant use”); allocated to mining and upgrading based on data provided by CNRL
		Electricity gen.	kWh/bbl bitumen	8.2	3.9	Electricity generation data reported in AER ST39 (“electricity generated”); allocated to mining and upgrading based on data provided by CNRL
		Net electricity imported	kWh/bbl bitumen	3.3	2.1	Calculated from electricity production and plant use data in AER ST39.
		Fraction electricity generated on-site		0.71	0.66	Calculated from electricity production and plant use data in AER ST39. Linked to “inputs” worksheet.
		Gasoline use	gal diesel/bbl bitumen	0.11	0.05	Annual volume of gasoline consumed reported in SGER reports, provided by CNRL
		Flaring-oil-ratio	scf/bbl bitumen	0	0	All flaring data reported to AER ST39 allocated to upgrading
Hea vy	Upgrading data table	API gravity of resulting upgraded product output	deg API	35.0	35.0	CNRL Horizon crude assay from crudemonitor.ca

	Process gas (PG) yield per bbl SCO output	scf/bbl SCO	404	501	Process gas consumption data reported in AER ST39; allocated to mining and upgrading based on data provided by CNRL
	- Fraction PG to self use - Heating (W/O cogen)		0.404	0.650	Calculated from AER ST39 data
	- Fraction PG to self use - H2 gen		0.000	0.000	
	- Fraction PG exported		0.582	0.325	
	- Fraction PG flared		0.014	0.025	
	Coke yield per bbl SCO output	kg/bbl SCO	41.0	36.6	Coke production data reported in AER ST39; all coke is stockpiled by CNRL
	- Fraction coke to self use - Heating		0.0	0.0	
	- Fraction coke exported		0.0	0.0	
	- Fraction coke stockpiled		1.0	1.0	
	Electricity intensity	kWh/bbl SCO	13.7	7.1	Electricity consumption data reported in AER ST39; allocated to mining and upgrading based on data provided by CNRL
	- Fraction electricity self generated W/ cogen	0-1	0.66	0.66	
	- Cogenerated heat as steam	mbtu/bbl SCO	21.2	21.2	
	- NG to cogen unit	scf/bbl SCO	55.6	56.3	Calculated in OPGEE
	Natural gas intensity (W/O cogen)	scf NG per bbl SCO	588.6	620.2	Calculated in OPGEE
	- Fraction NG - Heating (W/O cogen)		0.47	0.51	Calculated in OPGEE
	- Fraction NG - H2		0.53	0.49	
	Cogen turbine efficiency	btu e- per btu NG LHV	0.30	0.30	OPGEE default
	Cogeneration steam efficiency	btu steam enthalpy per btu NG LHV	0.40	0.40	OPGEE default
	Steam boiler efficiency	btu steam enthalpy/btu NG LHV	0.80	0.80	OPGEE default
	SCO/bitumen ratio	bbl SCO/bbl bitumen	0.85	0.86	Calculated based on SCO leaving facility and bitumen sent to upgrader in AER ST39 (“SCO deliveries” and “bitumen further processing”)

Table B-3. List of input parameters used in OPGEE to model MEG SAGD and eMSAGP pathways (base case inputs)

Parameter	Unit	eMSAGP Value	eMSAGP Reference	SAGD Value	SAGD Reference

Inputs Sheet	Production Methods	Downhole pump		1		1	
		Water reinjection		0		0	
		Natural gas reinjection		0		0	
		Water flooding		0		0	
		Gas lifting		0		0	
		Gas flooding		1		0	
		Steam flooding		1		1	
		Oil sands mine (integrated with upgrader)		0		0	
		Oil sands mine (non-integrated with upgrader)		0		0	
	Field properties	Field age	yr	5	[1]	5	[1]
		Field depth	ft	1246.7	[1]	1246.7	[1]
		Oil production volume	bbl/d	81,720	[2] 2018 daily production average	81,720	[2] 2018 daily production average
		Number of producing wells		171	[1]	171	[1]
		Number of water injecting wells		126	[1]	126	[1]
		Production tubing diameter	in	3.5	[1]	3.5	[1]
		Productivity index	bbl/psi-d	Calculated	Determined by a lognormal distribution in OPGEE	Calculated	Determined by a lognormal distribution in OPGEE
		Reservoir pressure	psi	319.3	[1]	319.3	[1]
		Reservoir temperature	˚F	383	[1]	383	[1]
		Offshore?		0		0	
	Fluid properties	API gravity	˚API	8	[3]	8	[3]
		Gas composition	mol%				
		N2		0.41	[4]	2	OPGEE default
		CO2		6.00		6	
		C1		80.41		84	
		C2		4.91		4	
		C3		7.55		2	
		C4+		0.60		1	
		H2S		0.12		1	
	Produc	GOR	scf/bbl oil	137	Calculated with [1] & [2]	28.07	[7]

	Gas flooding injection ratio	scf/bbl oil		Confidential data provided by MEG	N/A	
	Flood gas: 1 = natural gas, 2 = nitrogen, 3 = carbon dioxide		1	[5]	N/A	
	WOR	bbl water/bbl oil	2.41	[2] Production weighted average	2.6	Baseline operation data provided by MEG
	Fraction of produced gas reinjected		0.11	[2] Production weighted average	0.11	[2] Production weighted average
	SOR	bbl steam/bbl oil	2.38	[2] Production weighted average	2.6	Baseline operation data provided by MEG
	Fraction of required electricity generated onsite		1.0	[1]	1.0	[1]
	Fraction of steam generation via cogeneration		0.5	[3]	0.5	[3]
Processing practices	Flaring-to-oil ratio	scf/bbl oil	0.0019	[6]	0.0019	[6]
	Venting-to-oil ratio	scf/bbl oil	0	[6]	0	[6]
	Volume fraction of diluent		0.27	Communication with MEG	0.27	Communication with MEG
	Heater/treater		1	[1]	1	[1]
	Stabilizer column		0		0	
	Associated Gas Processing Path		Acid Gas: Dehydrator + Amine Process	[1]	Acid Gas: Dehydrator + Amine Process	[1]
Crude oil transport	Fraction of oil transported by each mode					
	Ocean tanker			Confidential data provided by MEG		Confidential data provided by MEG
	Barge					
	Pipeline					
	Rail					
	Truck					
	Transport distance (one way)	Mile				
	Ocean tanker			Confidential data provided by MEG		Confidential data provided by MEG
	Barge					
	Pipeline					
	Rail					

		Truck					
	Small sources emissions		g CO_2eq/MJ	0	Communication with MEG	0	Communication with MEG
	Well and downhole pump	Well head pressure	psi	160	[7]	160	[7]
		Wellhead temperature	˚F	351	[7]	351	[7]
Secondary Inputs Sheet	**Heavy oil dilution**	Diluent API gravity	˚API	63.3	CRW 5 yr average	63.3	CRW 5 yr average
		Diluent temperature	˚F	39.2	[7] -- stream 119	39.2	[7] -- stream 119
		Diluent pressure	psia	275.8	[7] -- stream 119	275.8	[7] -- stream 119
		Final diluted crude mixture temperature	˚F	113.0	[7] -- stream 121	113.0	[7] -- stream 121
		Final diluted crude mixture pressure	psia	159.7	[7] -- stream 121	159.7	[7] -- stream 121
		Desired steam quality		1	[4]	1	[4]
		Steam quality at generator outlet		0.78	[3]	0.78	[3]
		Fraction of blowdown water recycled		0.9	OPGEE default	0.9	OPGEE default
		OTSG excess air in combustion	lbmol O_2 real/lbmol O_2 stoichiometric	1.2		1.2	
		OTSG inlet air temperature	˚F	32.36	Edmonton annual average	32.36	Edmonton annual average
		OTSG outlet exhaust temperature	˚F	340	[6]	340	[6]
		OTSG blowdown heat recovery availability		1	[1]	1	[1]
		OTSG blowdown heat recovery efficiency		0.95	OPGEE default	0.95	OPGEE default
		OTSG blowdown water rejection temperature	˚F	194	[7]	194	[7]
		Turbine type		GE 7EA	Communication with MEG	GE 7EA	Communication with MEG
		Gas turbine fuel- Fraction natural gas		0.81	Calculated from data provided by MEG	0.93	Calculated from [2]
		Gas turbine fuel- Fraction produced gas		0.19		0.07	
		HRSG outlet exhaust temperature	˚F	327	[7]	327	[7]

	Gas turbine exhaust temperature	˚F	999	[8]	999	[8]
	Gas turbine output partition - MJ electricity/MJ LHV input fuel		0.30	[8] states efficiency of 0.329; turned down to 0.30 to account for aging and to match with reported electricity generation	0.30	[8] states efficiency of 0.329; turned down to 0.30 to account for aging and to match with reported electricity generation
	Gas turbine output partition - MJ loss/MJ LHV input fuel		0.032	OPGEE default for turbine type C	0.032	OPGEE default for turbine type C
	Gas turbine output partition - MJ exhaust/MJ LHV input fuel		0.668	Calculate from the other two partition	0.668	Calculate from the other two partition

[1]Sources: [1] ISPP; [2] In-situ Water Publication; [3] MEG 2017 Annual Information Form; [4] Tested by Maxxam and reports provided by MEG; [5] MEG eMSAGP; [6] AER ST-60; [7] MEG Phase 3 Application; [8] GE 7EA turbine specification.

Table B-4. List of input parameters used in OPGEE to model Imperial SA-SAGD and reference SAGD pathway (base case inputs)

		Parameter	Unit	Value	Reference
Inputs Sheet	**Production Methods**	Downhole pump		1	
		Water reinjection		0	
		Natural gas reinjection		0	
		Water flooding		0	
		Gas lifting		0	
		Gas flooding		0	
		Steam flooding		1	
		Oil sands mine (integrated with upgrader)		0	
		Oil sands mine (non-integrated with upgrader)		0	
	Field properties	Field age	yr	1	
		Field depth	ft	787	(IOL 2013, 2015)
		Oil production volume	bbl/d	81,000	(IOL 2018)
		Number of producing wells		370	(IOL 2013)
		Number of water injecting wells		370	(IOL 2013)
		Production tubing diameter	in	5.5	(IOL 2013)

	Productivity index	bbl/psi-d	calculated	Determined by a probability distribution in OPGEE
	Reservoir pressure	psi	377.3	(IOL 2013)
	Reservoir temperature	˚F	438.8	(IOL 2013)
	Offshore?		0	
Fluid properties	API gravity	˚API	8	(IOL 2013)
	Gas composition	mol%		(IOL 2013)
	N2		0.95	
	CO2		4.14	
	C1		94.03	
	C2		0.13	
	C3		0.07	
	C4+		0.64	
	H2S		0.03	
Production practices	GOR	scf/bbl oil	28.1	(IOL 2015)
	WOR	bbl water/bbl oil	1.65	(IOL 2015)
	SOR	bbl steam/bbl oil	1.65	(IOL 2015)
	Fraction of required electricity generated onsite		1.00	Communication with IOL
	Fraction of steam generation via cogeneration		0.4	Communication with IOL
Processing practices	Flaring-to-oil ratio	scf/bbl oil	0.0025	
	Venting-to-oil ratio	scf/bbl oil	0	
	Fugitive-to-oil ratio	kgCO2eq/bbl oil	0.14	(IOL 2018)
	Volume fraction of diluent		0.25	(IOL 2015)
	Heater/treater		1	
	Stabilizer column		0	
	Associated Gas Processing Path		Acid Gas: Dehydrator + Amine Process	
Crude oil transport	Fraction of oil transported by each mode			
	Ocean tanker		0	
	Barge		0	
	Pipeline		1	
	Rail		0	
	Truck		0	
	Transport distance (one way)	Mile		
	Ocean tanker		0	
	Barge		0	
	Pipeline		1553	
	Rail		0	

	Truck		0	
	Small sources emissions	g CO_2eq/MJ	0	Communication with IOL
Secondary Inputs Sheet — **Well and downhole pump**	Well head pressure	psi	230.8	(IOL 2015)
	Wellhead temperature	˚F	327.2	(IOL 2015)
	Diluent temperature	˚F	39.2	(IOL 2015)
	Diluent pressure	psia	275.8	(IOL 2015)
	Final diluted crude mixture temperature	˚F	113.0	(IOL 2015)
	Final diluted crude mixture pressure	psia	159.7	(IOL 2015)
	Final diluted crude API gravity	˚API	19	General pipeline specifications
Produced water	Evaporator energy consumption	kWh/bbl input water	3.26	Communication with IOL
Steam Generation	Fraction of injected solvent lost to reservoir		0.11	(IOL 2015)
	Desired steam quality		1	(IOL 2015)
	Steam quality at generator outlet		1	(IOL 2018)
	Drum boiler- Fraction natural gas		0.98	Communication with IOL
	Drum boiler- Fraction produced gas		0.02	Communication with IOL
	Drum boiler excess air in combustion	lbmol O_2 real/lbmol O_2 stoichiometric	1.2	
	Drum boiler outlet exhaust temperature	˚F	323.33	(IOL 2018)
	Turbine type		GE 7EA	(IOL 2013)
	Gas turbine fuel- Fraction natural gas		1	Communication with IOL
	Gas turbine fuel- Fraction produced gas		0	Communication with IOL
	HRSG outlet exhaust temperature	˚F	332.3	(IOL 2018)
	Gas turbine output partition - MJ electricity/MJ LHV input fuel		0.327	OPGEE default for GE 7EA turbine type
	Gas turbine output partition - MJ exhaust/MJ LHV input fuel		0.641	Calculated
	Gas turbine output partition - MJ loss/MJ LHV input fuel		0.032	OPGEE default for GE 7EA turbine type

C. Model evaluation

C.1. First iteration of model validation for existing pathways

Preliminary results for existing pathways developed from the first round of company feedback are presented in Tables B1 to B3, below. Assumptions made in developing GHG intensity estimates are documented in table notes. For each year of operating data upon which emissions intensity estimates are based (2015 and 2016 for mining pathways, 2015 for SAGD pathway), OPGEE was run using operating data from that project and year of operation using base case assumptions (see table notes). Publicly reported emissions data employed in the model comparison include only direct emissions (on-site emissions, e.g., process fuel combustion, flaring, and fugitive emissions). OPGEE base case estimates include direct emissions as well as indirect emissions from land use change, upstream natural gas, diesel, electricity (grid) emissions, as well as emissions from the diluent supply chain where applicable. Emissions are reported per MJ of dilbit delivered (leaving project site) for the dilution pathways (Imperial Kearl and MEG Christina Lake) and per MJ SCO delivered (leaving project site) for the upgrading pathway (CNRL Horizon). For all years and pathways where OPGEE results were compared to company reported data, emissions intensity estimates were within 5.5%. These base case results are still preliminary and the research group is continuing to work with industry representatives to update their GHG intensity data. A detailed sensitivity analysis will be conducted on key model parameters (listed in Section 6.1).

Table C-1. Preliminary upstream, crude transport, and refinery GHG intensity results for Imperial Kearl pathway

<table>
<tr><th rowspan="2"></th><th colspan="2">2015 Upstream GHG [g CO2e/MJ dilbit]</th><th colspan="2">2016 Upstream GHG [g CO2e/MJ dilbit]</th></tr>
<tr><th>SGER reported[1]</th><th>OPGEE base case estimate[2]</th><th>SGER reported[1]</th><th>OPGEE base case estimate[2]</th></tr>
<tr><td>Drilling and Maintenance</td><td rowspan="5">Aggregate data reported</td><td>0</td><td rowspan="5">Aggregate data reported</td><td>0</td></tr>
<tr><td>Processing[3]</td><td>5.17</td><td>5.00</td></tr>
<tr><td>Venting and flaring[4]</td><td>0.15</td><td>0.14</td></tr>
<tr><td>Fugitives[5]</td><td>0.03</td><td>0.04</td></tr>
<tr><td>Misc.</td><td>0</td><td>0</td></tr>
<tr><td>Subtotal direct upstream</td><td>5.18</td><td>5.36</td><td>5.13</td><td>5.18</td></tr>
<tr><td>Exploration and Waste</td><td rowspan="6">Excluded from SGER</td><td>0</td><td rowspan="6">Excluded from SGER</td><td>0</td></tr>
<tr><td>Land Use[6]</td><td>3.0</td><td>3.0</td></tr>
<tr><td>Net electricity supply</td><td>1.21</td><td>1.24</td></tr>
<tr><td>Upstream diesel supply</td><td>0.18</td><td>0.18</td></tr>
<tr><td>Upstream NG supply[7]</td><td>0.53</td><td>0.51</td></tr>
<tr><td>Upstream diluent supply[8]</td><td>1.56</td><td>1.60</td></tr>
</table>

Subtotal indirect upstream	N/A	**6.48**	**N/A**	**6.52**
Total upstream	**N/A**	**11.8**	**N/A**	**11.7**
Transport[9]	N/A	1.30	N/A	1.30
Refinery[10]	N/A	10.0	N/A	10.0
Total Well-to-Refinery exit GHG	**N/A**	**23.1**	**N/A**	**23.0**

Notes: [1]SGER reported emissions (t CO_2e for project) converted to intensity based on MJ dilbit delivered (leaving site). Source: GHGRP (2018). [2]Base case estimate assumes all diluent is locally sourced; OPGEE updated with AER ST39 data (AER ST39 2019a) except fugitives (AEMERA 2015) and diesel (COSIA 2015). [3]Combustion emission factors ("Processing" stage) adjusted to be consistent with those in "CCI Quantification Methodologies report v1.1." Source: Alberta Climate Change Office (2018). [4]Assumes all NG flared/vented reported to AER is flared (no venting). [5]2015 fugitive GHG from AEMERA dataset; 2016 fugitive GHG is average of 2013-2015 (2016 data not available). [6]Land use emissions from Yeh et al. (2015). No Kearl data is available so Muskeg River is employed as proxy). [7]Base case NG upstream GHG: 7.2 g CO2e/MJ (ICF Canada 2012). [8]Base case diluent supply assumes all diluent is sourced locally from AB/BC/SK with an upstream emission factor of 7.2 g CO2e/MJ (ICF Canada 2012).

Table C-2. Preliminary upstream, crude transport, and refinery GHG intensity results for CNRL Horizon pathway

	2015 GHG intensity [g CO2e/MJ SCO]		**2016 GHG intensity [g CO2e/MJ SCO]**	
	SGER reported[1]	**OPGEE base case estimate[2]**	**SGER reported[1]**	**OPGEE base case estimate[2]**
Drilling and Maintenance	0	0	0	0
Processing[3]	Aggregate data reported	9.79	Aggregate data reported	10.9
Natural gas for H2		3.52		3.53
Venting and flaring[4]		0.98		0.36
Fugitives[5]	1.03	1.03	1.03	1.69
Misc.	0	0	0	0
Subtotal direct Upstream	**14.5**	**15.3**	**15.3**	**16.5**
Exploration and Waste	Excluded from SGER	0	Excluded from SGER	0
Land Use[6]		2.90		2.9
Net electricity supply		1.16		1.42
Upstream diesel supply[7]		0.42		0.40
Upstream NG supply[8]		0.74		1.05
Subtotal indirect upstream	N/A	**5.20**	**N/A**	**5.77**
Total upstream	**N/A**	**20.5**	**N/A**	**22.3**
Transport	N/A	1.20	N/A	1.20

Refinery	N/A	7.05	N/A	7.05
Total Well-to-Refinery exit	**N/A**	**28.8**	**N/A**	**30.5**

Notes: [1]SGER reported emissions (t CO_2e for project) converted to intensity based on MJ SCO delivered (SCO produced less SCO consumed on-site for fuel and as diluent). Source: GHGRP (2018). [2]Diesel consumption estimated based on SGER-reported diesel consumption (2016); other energy inputs in OPGEE updated with operating data from AER ST39 (2019a). [3]Combustion emission factors ("Processing" stage) adjusted to be consistent with those in "CCI Quantification Methodologies report v1.1". Source: Alberta Climate Change Office (2018). [4]Assumes all NG flared/vented reported to AER is flared (no venting). [5]2015 fugitive GHG from AEMERA (2015) dataset; 2016 fugitive GHG is average of 2013-2015 (2016 data not available). [6]Land use emissions from Yeh et al. (2015). [7]No upstream emissions allocated to diesel produced and consumed on-site ("SCO fuel use" reported to AER). [8]Base case NG upstream GHG: 7.2 g CO2e/MJ (ICF Canada 2012)

Table C-3. Preliminary upstream, crude transport, and refinery GHG intensity results for MEG Christina Lake pathway

	December 2015 GHG intensity [g CO2e/MJ dilbit]	
	MEG reported GHG intensity[1]	**OPGEE base case estimate**
Drilling	Aggregate data reported	0.00
Processing		9.38
Electricity Export		-4.00
Maintenance		0.00
Venting, flaring, fugitives[2]		0.07
Misc.		0.50
Subtotal direct upstream	**6.03**	**5.95**
Exploration	Excluded from reported emissions data	0.00
Waste		0.00
Land Use[3]		0.56 – 0.89
Upstream NG supply[4]		1.09 – 2.44
Upstream diluent supply[5]		1.59 – 3.54
Subtotal indirect upstream	N/A	**4.54 – 8.17**
Total upstream	**N/A**	**10.5 – 14.1**
Transport	N/A	1.30
Refinery	N/A	8.34
Total Well-to-Refinery exit	**N/A**	**18.7 – 22.2**

Notes: [1]MEG reported GHG intensity from MEG Energy Corp. (2008). [2]Venting, flaring, and fugitives from AER ST60 dataset (AER 2019b). [3]Land use change emissions from Yeh et al. (2015). [4]Base case NG upstream GHG: 7.2 g CO2e/MJ (ICF Canada 2012). [5]Base case diluent supply assumes all diluent is sourced locally from AB/BC/SK with an upstream emission factor of 7.2 g CO2e/MJ (ICF Canada 2012)

C.2 OTSG and HRSG model validation in OPGEE

OPGEE 3.0 uses an updated steam generation module which employs XSteam to calculate enthalpy changes and fuel requirements (Masnadi et al. 2019). When modelling MEG CLRP facilities, detailed stream properties including water temperature and pressure at different stages are taken from Table 3-2.4 MEG's CLRP Phase 3 application submitted to AER. For validating the OTSG and HRSG models in OPGEE, MEG provided confidential monthly data of fuel consumption in OTSGs and turbines, as well as detailed solution gas composition tested by Maxxam in 2018. The overall error in natural gas consumption is -4.4% for the year 2018, with some months of overestimation and other months of underestimation. The modeled electricity generation is -2.6% from the reported 2018 generation. The error of modeled electricity consumption by facilities onsite is -2.5%. It is concluded that the OPGEE steam generation module is sufficiently accurate given good input data quality.

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