Oil Production Greenhouse Gas Emissions Estimator

OPGEE v1.1 DRAFT A

User guide & Technical documentation

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Part I

Introduction and user guide

1 Introduction

The Oil Production Greenhouse gas Emissions Estimator (OPGEE) is an engineering-based life cycle assessment (LCA) tool that estimates greenhouse gas (GHG) emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery gate (see Figure 1.1).

This technical documentation introduces OPGEE and explains the calculations and data sources in the model. First, the overall goals and motivation for OPGEE are described. Then, the general structure of OPGEE is introduced with a brief explanation of the worksheets contained in the model. Next, each production stage is explained in detail, outlining the methods and assumptions used to generate estimates of energy use and emissions for that stage. Then supplemental calculation worksheets are outlined. Next, the gathering worksheets which collect and aggregate intermediate results are described. Lastly, we describe the worksheets that contain fundamental data inputs.

1.1 Model motivation

Current research suggests that GHG emissions from petroleum production can be quite variable [1–8]. Facilities will have low GHG emissions per unit of energy produced if they do not rely on energy intensive production methods and apply effective controls to fugitive emissions sources. In contrast, some crude oil sources can have higher GHG emissions if they rely on energy-intensive production methods.

The variability in crude oil production emissions is partly due to the use of energy-intensive secondary and tertiary recovery technologies [6, 9, 10]. Another major factor is significant variation in the control of venting, flaring and fugitive (VFF) emissions [11–13]. Other emissions arise from increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio).

The existing set of general fuel cycle emissions models, exemplified by GREET and GHGenius [10, 14], cover a wide range of transport fuels, from biofuels to electric vehicles. These broad models have the advantage of being publicly available and transparent. Unfortunately, they lack process-level detail for any particular fuel cycle and only represent pathway averages. For example, all conventional crude oil production in GREET is modeled using a

Box 1.1. Goals of OPGEE

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.
2. Use detailed data, where available, to provide maximum accuracy and flexibility.
3. Use public data wherever possible.
4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g. refining)

common default production pathway, fuel mix, and energy efficiency. While these LCA tools have been useful to date, future regulatory approaches will require a more specific method of assessing the differences between crude oil sources.

1.2 OPGEE model goals

The goals of OPGEE development are listed in Box 1.1.

First, OPGEE is built using engineering fundamentals of petroleum production and processing. This allows more flexible and accurate emissions estimations from a variety of emissions sources.

OPGEE is constructed using *Microsoft Excel* to ensure transparency and maximum accessibility by stakeholders, including industry, governments, and members of the public. OPGEE will be available for download from Stanford University servers, and servers of future institutions in which Adam Brandt is employed. This will ensure its future availability. Regular updates of the model are expected in intervals of 1-2 years.

Another goal of OPGEE is the generation of comprehensive documentation. Model functions and input data are documented within the *Excel* worksheet to allow effective use and modification of the tool by users. This document serves to explain model calculations and assumptions and provides information on model data sources.

1.3 OPGEE model construction

1.3.1 Model functional unit

The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional

unit is held constant across different production and processing pathways included in OPGEE. This functional unit allows integration with other fuel cycle models that calculate refinery emissions per unit of crude oil processed, and will enable ntegration with future work on refinery models. The heating value basis can be chosen as lower or higher heating value (LHV or HHV), depending on the desired basis for the emissions intensity. The model defaults to LHV basis for best integration with GREET.

1.3.2 Model scope and focus

OPGEE includes emissions from all production operations required to produce and transport crude hydrocarbons to the refinery gate (see Figure 1.1 for model system boundaries). Included production technologies are: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion.

1.3.3 Spreadsheet structure

OPGEE is modular in structure, with interlinked worksheets representing each production stage. Within each major production stage, a number of activities and processes occur (e.g., fluid production or fluid injection). Calculations take place sequentially and are numbered in a hierarchical fashion (see Box 1.1 for explanation of pointers to the model in this document).

1.3.4 Modeling detail and default specifications

OPGEE models oil production emissions in more detail than previous LCA models. For example, the energy consumed in lifting produced fluids (oil, water, and associated gas) to the surface is computed using the fundamental physics of fluid lifting, accounting for lifting efficiencies and pump efficiencies.

Increased modeling detail results in an increase in the number of model parameters. All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given facility, most input values will remain equal to defaults. In contrast, if detailed field-level data are available, a more accurate emissions estimate can be generated.

For some processes and sub-processes, correlations or relationships are developed for defaults, which we call "smart defaults". For example, the amount of water produced with oil (water-oil-ratio, or WOR) affects the energy consumed in lifting, handling, and separating fluids. If the WOR is known, it can be inputed directly. However, in some regions, water production is not reported, so OPGEE includes a statistical relationship for water production as a function of reservoir age (see Appendix **??** for a description of the analysis underlying this smart default).

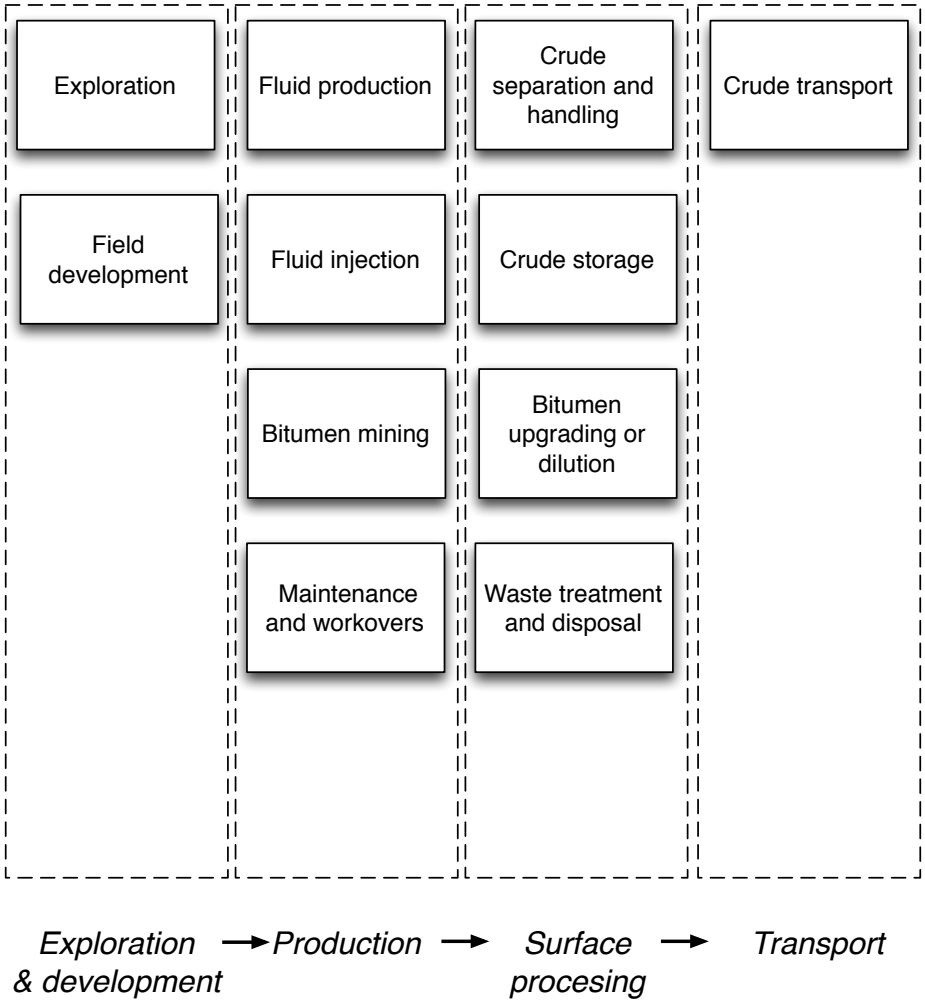


Figure 1.1: Schematic chart showing included stages within OPGEE.

A workflow for updating and improving the data basis and accuracy of an emissions estimate using OPGEE is shown in Figure 1.2. This workflow represents one possible way that OPGEE could be used.

1.3.5 Emissions sources classification

Each process stage or sub-process in OPGEE can result in a variety of emissions sources. For example, the *'Drilling & Development'* process stage includes the terrestrial drilling sub-process. Terrestrial drilling includes the following emissions sources:

- Combustion emissions from drilling rig prime mover;
- Flaring emissions from drilling rig (for reservoirs with significant gas production);
- Vents and other upset emissions from drilling rig;

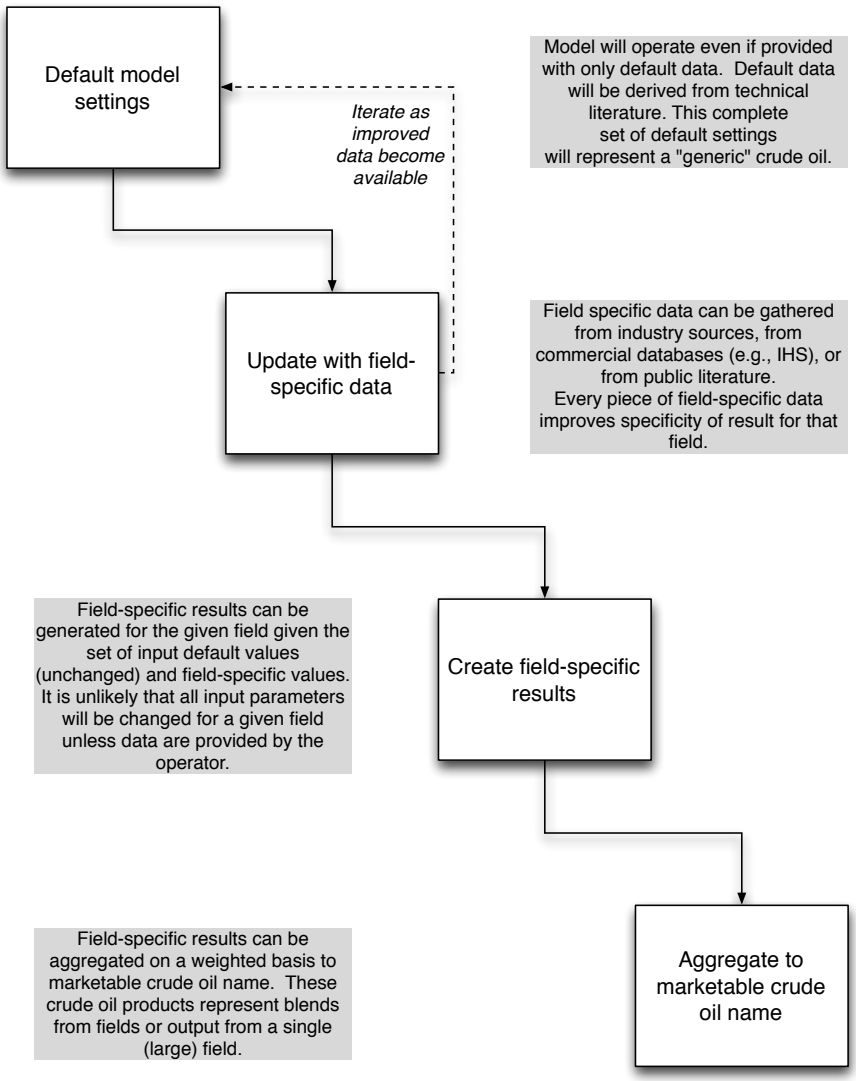


Figure 1.2: Proposed workflow for improving emissions estimates using OPGEE.

- Combustion emissions from work performed in land clearing and site preparation;
- Biogenic emissions from ecosystem disturbance during development;
- Embodied emissions in cement and casing;
- Embodied emissions in other consumable materials (e.g., fracturing sand)

Note that these emissions sources are of significantly different magnitude and have different causation and potential methods of mitigation. In total, over 100 emissions sources are classified in OPGEE v1.1 across all process stages (e.g., all included processes and sub-processes). See Appendix C for a complete tabulation and classification of emissions sources.

Table 1.1: Emissions classification, order of magnitude emissions, and significance description.

Class	Est. mag. [gCO_2/MJ]	Description
*	0.01	Minor emissions sources not worthy of further study or estimation. This is the most common classification. One-star emissions are accounted for by adding a value for miscellaneous minor emissions.
**	0.1	Minor emissions sources that are often neglected but may be included for physical completeness.
***	1	Sources that can have material impacts on the final GHG estimate, and therefore are explicitly modeled in OPGEE.
****	10	Sources that are large in magnitude (though uncommon). Examples include steam production for thermal oil recovery and associated gas flaring. These sources are significant enough to require their own dedicated OPGEE modules.

1.3.6 Emissions source significance cutoffs

It would be infeasible (and counter-productive) for regulators or producers to attempt to estimate or model the magnitude of every emissions source listed in Appendix C. Fortunately, a small number of emissions sources will result in most of the emissions from petroleum production operations.

For this reason, emissions sources included in the OPGEE system boundary are classified by estimated emissions magnitude. These emissions magnitudes are meant to represent *possible* emissions magnitudes from a source, not the actual emissions that would result from that source for any particular field. An order-of-magnitude estimation approach is used, with each source assigned a rating in "stars" from one-star (*) to four-star (****) corresponding to 0.01 to 10 g CO_2 eq. per MJ of crude oil delivered to the refinery gate. These classifications are explained in more detail in Table 1.1.

Emissions estimated to be one-star emissions (*) are not modeled in OPGEE due to insignificant magnitude. Since these small sources are known to have non-zero emissions, they are included in the overall emissions estimate by including a "small sources" term. Two-star (**) sources are included simply or are included in the small sources term. Often, two-star sources are minor in magnitude, but are modeled due to the need to model the physics and chemistry of crude oil production and processing.[1] Three-star (***) sources are explicitly modeled in OPGEE. Four-star sources (****) are modeled in detail with stand-alone modules to allow variation and uncertainty analysis.

User Inputs & Results 3.9

[1] No strict criteria exist to determine the inclusion or exclusion of two-star sources. Modeler judgement is applied to determine the need for modeling these sources.

1.3.7 Data sources

Because of the need for transparent data basis, OPGEE uses data from a variety of technical reference works. For example, emissions factors are derived from standard engineering references from the American Petroleum Institute (API) and EPA [15, 16]. A large number of technical references, journal articles, and fundamental data sources have been consulted during the construction of OPGEE, including:

- Exploration and drilling [16–23]
- Production and surface separations [15, 16, 24–53]
- Secondary and tertiary recovery [54–59]
- Water treatment and waste disposal [23, 48, 51, 60–63]
- Venting, flaring, and fugitive emissions [24–26, 26–33, 64–68]
- Petroleum transport and storage [30, 33, 43, 67, 69–73]

2 User guide

OPGEE is divided into three types of worksheets: (i) process stage worksheets, (ii) supplementary worksheets, and (iii) output worksheets.

2.1 Process stage worksheets

Process stage worksheets form the core of OPGEE, and are where most model calculations occur. These worksheets have red-colored tabs.

2.1.1 *'Exploration'* worksheet

The *'Exploration'* worksheet contains pre-production emissions that occur during primary exploration for petroleum. These emissions are generally very small in magnitude when amortized over the productive life of an oil field, as they occur only at the outset of production. For this reason, these sources are classified as below the significance cutoff in OPGEE v1.1. Exploration emissions are described in more detail in Section 3.1, and emissions sources from exploration are listed and classified in Table C.1.

2.1.2 *'Drilling & Development'* worksheet

The *'Drilling & Development'* worksheet includes emissions that occur during development of crude oil production facilities. Key sources include drilling and land use impacts from land clearing and conversion. Drilling and development emissions tend to be relatively small because they only occur at the outset of production or sporadically during field life. Drilling and development emissions are described in more detail in Section 3.2, and emissions sources from drilling and development are listed and classified in Table C.2.

2.1.3 *'Production & Extraction'* worksheet

The *'Production & Extraction'* worksheet models the work required to lift fluids from the subsurface and to inject fluids into the subsurface. OPGEE includes the two most common lifting technologies: sucker-rod pumps and gas lift. Also included are the energy requirements of water flooding, gas flooding, and steam flooding. The lifting model used for calculating lifting energy is a single phase flow model which neglects gas slippage. Injection horsepower is

calculated based on operating pressures and temperatures using fundamental physics. Production emissions are described in more detail in Section 3.3, and emissions sources from production are listed and classified in Table C.3.

2.1.4 *'Surface Processing'* worksheet

The *'Surface Processing'* worksheet models handling of crude, water, and associated gas with a set of common industry technologies. By defining default configurations and parameter values, the amount of data required is reduced. For example, in gas processing, default processes are assumed such as the amine-based acid gas removal (AGR) and glycol-based gas dehydration units. Process flow diagrams are included in the surface processing worksheet for improved readability. Surface processing emissions are described in more detail in Section 3.4, and emissions sources from surface processing are listed and classified in Table C.4.

2.1.5 *'Maintenance'* worksheet

The *'Maintenance'* worksheet includes venting and fugitive emissions associated with maintenance. These emissions occur during compressor blowdowns, well workovers and cleanups, and gathering pipeline maintenance. Maintenance emissions are described in more detail in Section 3.5, and emissions sources from maintenance are listed and classified in Table C.5.

2.1.6 *'Waste Disposal'* worksheet

The *'Waste Disposal'* worksheet includes emissions associated with waste disposal are within the system boundary of OPGEE. These sources are believed to be below the significance cutoff, so they are not explicitly modeled in OPGEE. Waste disposal emissions are described in more detail in Section 3.6, and emissions sources from waste disposal are listed and classified in Table C.6.

2.1.7 *'Crude Transport'* worksheet

The *'Crude Transport'* worksheet calculations allow variation in transport modes and in the distance travelled. Transport emissions are modeled using the method established in CA-GREET [74]. Transport emissions are described in more detail in Section 3.7, and emissions sources from transport are listed and classified in Table C.7.

2.1.8 *'Bitumen Extraction & Upgrading'* worksheet

The *'Bitumen Extraction & Upgrading'* worksheet models extraction of crude bitumen separately from the production of conventional crude oil, due to the differences in technologies applied (e.g., mining and upgrading equipment have

no analogues in conventional crude oil operations). Instead of detailed process models, data from the GHGenius model are included in OPGEE v1.1[10]. Bitumen extraction and upgrading emissions are described in more detail in Section 3.8.

2.2 Supplementary worksheets

Supplementary worksheets support calculations throughout OPGEE, including: calculating intermediate outputs in the process stage worksheets, compiling output in the gathering worksheets, and calculating final results in the *'User Inputs & Results'* worksheet. Supplementary worksheets have blue-colored tabs.

'Gas Balance' worksheet This worksheet tracks produced gas composition from production to final user or sale to ensure that all produced gas is accounted for in the gas processing equipment, VFF emissions, and final gas sales. The *'Gas Balance'* worksheet is described in Section 4.1

'Steam Injection' worksheet This worksheet is supplementary to the production and extraction worksheet and calculates in detail the natural gas consumed and electricity cogenerated (if applicable) during steam generation. The *'Steam Injection'* worksheet is described in Section 4.2

'Electricity' worksheet This worksheet determines the offsite electricity mix and calculates the energy consumption in onsite electricity generation (other than electricity co-generated with steam). The *'Electricity'* worksheet is described in Section 4.3.

'Drivers' worksheet This worksheet provides a database of energy consumption for different types and sizes of prime movers (gas and diesel engines, gas turbines and electric motors). The *'Drivers'* worksheet is described in Section 4.4

'Fuel Cycle' worksheet This worksheet retrieves and calculates the fuel cycle energy consumption and GHG emissions for the calculation of credits/debits from fuel exports/imports. The *'Fuel Cycle'* worksheet is described in Section 4.5.

'Emission Factors' worksheet This worksheet retrieves and builds emissions factors for the calculation of combustion and non-combustion GHG emissions from energy use and losses. The *'Emissions Factors'* worksheet is described in Section 4.6.

'Venting & Fugitives' worksheet This worksheet calculates in detail the GHG emissions associated with Venting and fugitives. The *'Venting & Fugitives'* worksheet is described in Section 4.7.

'Flaring' worksheet This worksheet calculates in detail the GHG emissions associated with flaring. The *'Flaring'* worksheet is described in Section 4.8.

'Fuel Specs' worksheet This worksheet provides fuel specifications required for OPGEE calculations. The *'Fuel Specs'* worksheet is described in Section 6.

'Input Data' worksheet This worksheet provides other needed data inputs such as conversion factors and steam enthalpies. The *'Input Data'* worksheet is described in Section 6.

2.3 Output gathering worksheets

Output worksheets gather the information from the process stage calculations and compile them into summed energy consumption (including energy co-production credits) and summed GHG emissions (including any offsets from co-produced energy). Also included in the output worksheets is the worksheet where users input key parameters and display summary results. Output worksheets have green-colored tabs.

'Energy Consumption' worksheet The *'Energy Consumption'* worksheet gathers data on energy consumption for sub-processes from all process worksheets. Each main process worksheet is included in the gathering table. All energy consumed is summed by type across all stages. This gross consumption is used to compute net consumption and energy imports and exports. The *'Energy Consumption'* worksheet is described in Section 5.1

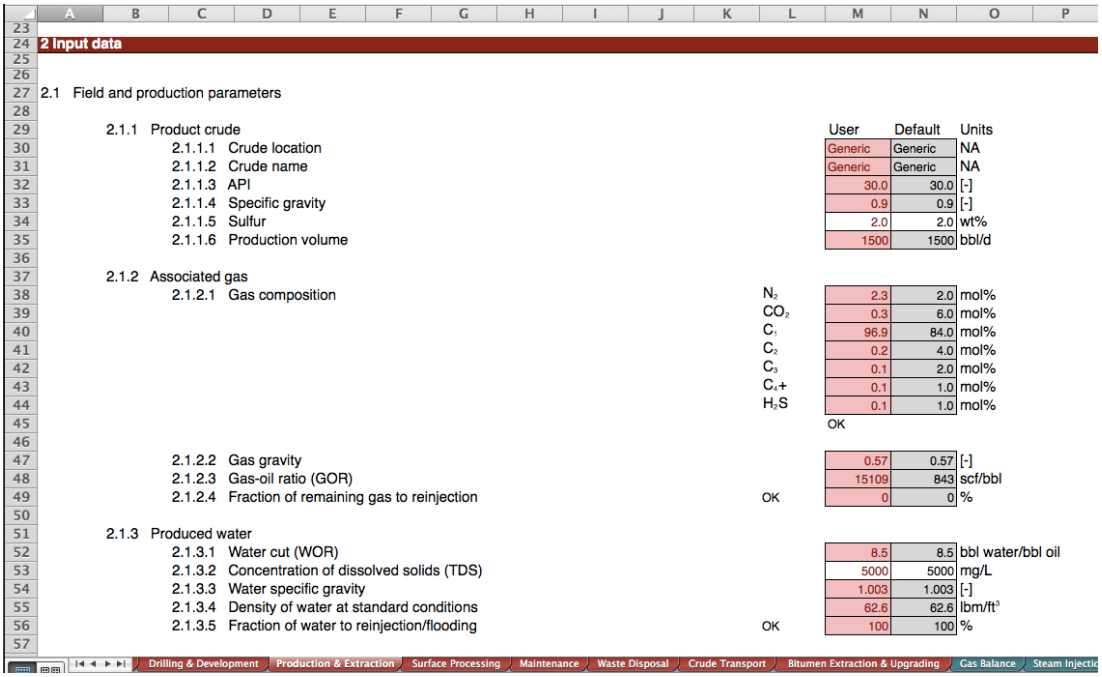
'GHG Emissions' worksheet The *'GHG Emissions'* worksheet takes the energy quantities consumed in each stage and converts them to emissions using emissions factors. It also gathers any emissions associated with land use change and VFF emissions. Emissions are computed as $gCO_2eq./d$. The *'GHG Emissions'* worksheet is described in Section 5.2.

'User Inputs & Results' worksheet The *'User Inputs & Results'* worksheet serves two functions. First, it serves as the place for primary model interaction (see below). Also, this worksheet presents summary results in tabular and graphical form. The *'User Inputs & Results'* worksheet is described in Section 5.3.

2.3.1 Structure of each worksheet

Each process stage worksheet is divided into two main sections: (i) input data and (ii) calculations. The input data section (see Figure 2.1) is where the user enters the input parameters (e.g., API gravity, production volume). The input section of each worksheet has two data columns: *User* and *Default*, in columns M and N, respectively. The cells within the *User* column are the active cells, and are used to generate results. The cells within the *Default* column are used for reference, bookkeeping of default values, and generating defaults using correlations based on field data.

Below the input data section is the calculations section of a worksheet, where intermediate model outputs are calculated. These intermediate outputs are summarized and compiled by the gathering worksheets to provide



		User	Default	Units
2 Input data				
2.1 Field and production parameters				
2.1.1 Product crude				
2.1.1.1 Crude location		Generic	Generic	NA
2.1.1.2 Crude name		Generic	Generic	NA
2.1.1.3 API		30.0	30.0	[-]
2.1.1.4 Specific gravity		0.9	0.9	[-]
2.1.1.5 Sulfur		2.0	2.0	wt%
2.1.1.6 Production volume		1500	1500	bbl/d
2.1.2 Associated gas				
2.1.2.1 Gas composition	N_2	2.3	2.0	mol%
	CO_2	0.3	6.0	mol%
	C_1	96.9	84.0	mol%
	C_2	0.2	4.0	mol%
	C_3	0.1	2.0	mol%
	C_4+	0.1	1.0	mol%
	H_2S	0.1	1.0	mol%
		OK		
2.1.2.2 Gas gravity		0.57	0.57	[-]
2.1.2.3 Gas-oil ratio (GOR)		15109	843	scf/bbl
2.1.2.4 Fraction of remaining gas to reinjection	OK	0	0	%
2.1.3 Produced water				
2.1.3.1 Water cut (WOR)		8.5	8.5	bbl water/bbl oil
2.1.3.2 Concentration of dissolved solids (TDS)		5000	5000	mg/L
2.1.3.3 Water specific gravity		1.003	1.003	[-]
2.1.3.4 Density of water at standard conditions		62.6	62.6	lbm/ft^3
2.1.3.5 Fraction of water to reinjection/flooding	OK	100	100	%

Figure 2.1: Input data section of *'Production & Extraction'* worksheet. User inputs are in column M, while defaults are kept as reference in column N.

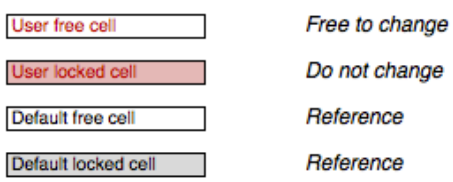


Figure 2.2: Types of cells. *User Free* and *Default Free* cells can be changed, while *Locked* cells should not be changed due to possibility of compromising model functionality.

the overall energy and emissions measures compiled in the *'User Inputs & Results'* worksheet.

2.3.2 Types of model cells

Four main types of cells exist in the calculation columns M and N: *User Free*, *User Locked*, *Default Free*, *Default Locked* (See Figure 2.2). As might be expected, locked cells should not be changed.[1] This is typically because locked cells contain formulas that draw on other cells and therefore should not be changed. "User Free" cells are cells that allow entry of user data.

[1]Note: 'locked' cells are not locked via *Excel* password-protected locking mechanism, so they can be changed if desired by the user. However, this should be done with care, as the model can easily be rendered inoperable.

Box 2.1: Using OPGEE documentation and model together

OPGEE model documentation aligns with the model itself. Pointers to the model are contained in the right-hand margin of the model documentation in red, italic text. For example, a reference to the Production & Extraction worksheet calculation of water specific gravity, which is calculation number 2.1.3.3 on that worksheet (see Figure 2.4, Row 54), would be referred to in the right-hand margin as *Production & Extraction 2.1.3.3*

2.4 Working with OPGEE

This section explains how to work with OPGEE. Box 2.1 shows how to best use this documentation in concert with the OPGEE model itself.

2.4.1 Primary interaction

The first level of interaction with OPGEE (which this document calls "primary" interaction) consists of changing a small number of key parameters to determine the energy consumption and emissions from an oil production facility. These key parameters have the following characteristics:

- They have a significant effect on the GHG emissions from an oil and gas operation;
- They vary significantly across different operations and therefore could cause variability between different fields or projects;
- They are likely to be measured or are well-understood by operators.

The list of key inputs is a relatively small list of important factors. Other factors excluded from this list are left to process worksheets.

2.4.1.1 Controls on the 'User inputs & Results' worksheet

The "User Inputs" section of the *'User Inputs & Results'* worksheet is where key field parameters can be easily changed (see Figure 2.3). These key parameters are explained below.

User Inputs & Results 3.1 - 3.9

Production methods Controls to turn on or off production methods including downhole pump, water reinjection, gas reinjection, water flooding, gas lifting, gas flooding, and steam flooding.

User Inputs & Results 3.1

- Downhole pump: This option is used when the natural energy of the reservoir is not enough to lift the fluids from the subsurface to the surface at the desired wellhead pressure.
- Water reinjection: This option is used when injecting a fraction of the produced water. This option does not apply if the amount of water injected is more than the amount of water produced after treatment.

- Gas reinjection: This option is used when injecting a percentage of the amount of gas produced. This option does not apply if the amount of gas injected is more than the amount of gas remaining after processing and VFF losses. The remaining gas is shown in the *'Gas Balance'* worksheet.

- Water flooding: This option is used when injecting an amount of water which is more than the amount of water produced. The amount of water injected is determined by the injection ratio (given in bbl water/bbl oil) and the fraction of water produced to reinjection/flooding must be set to 1.0. **The option of water reinjection must be turned OFF when the option of water flooding is turned ON.**

- Gas lifting: This option is used when gas is not injected into the reservoir, but injected into production tubular to reduce the pressure at the reservoir interface and induce production from the reservoir.

- Gas flooding: This option is used when injecting an amount of gas which is more than the amount of gas remaining after processing. The amount of gas injected is determined by the injection ratio (given in scf/bbl oil) and the fraction of remaining gas to reinjection must be set to 1.0. This option can also be used when flooding nitrogen gas. **The option of gas reinjection must be turned OFF when the option of gas flooding is turned ON.**

Field properties Field properties, including field location, field name, field age, field depth, oil production volume, number of producing wells, well diameter, productivity index, and average reservoir pressure. *User Inputs & Results 3.2*

Fluid properties A variety of fluid properties, including API gravity of crude oil and composition of produced associated gas. *User Inputs & Results 3.3*

Production practices A variety of production practices or operating ratios. These include gas-to-oil ratio (GOR), water-to-oil ratio (WOR), water-injection ratio, gas lifting injection ratio, gas flooding injection ratio, steam-to-oil ratio (SOR), fraction of required electricity generated on site, fraction of remaining gas reinjected, fraction of water produced reinjected, fraction of steam generation via co-generation and volume fraction of diluent. WOR, GOR, and SOR are common parameters and self explanatory. Other less common parameters are explained below. *User Inputs & Results 3.4*

- Water injection ratio: The ratio of the amount of water injected in water flooding to the amount of oil produced. This is required only when the option of water flooding is turned ON.

- Gas lifting injection ratio: The ratio of the amount of gas injected for lifting to the amount of liquid (water + oil) produced. The amount of gas injected for gas lifting **does not** include gas injected into the reservoir. This is required only when the option of gas lifting is turned ON.

- Gas flooding injection ratio: The ratio of the amount of gas injected in gas flooding to the amount of oil produced. This is required only when the option of gas flooding is turned ON.
- Fraction of required electricity generated onsite: This parameter determines the fraction of the electricity required that is generated onsite not including electricity co-generation with steam generation. The fraction entered can be greater than 1.0, designating electricity export to the grid.
- Fraction of remaining gas reinjected: This parameter determines the fraction of gas remaining that is reinjected into the reservoir. In the case of methane gas flooding this fraction must be equal to 1.0 (the amount of gas injected is more than the amount of gas remaining).
- Fraction of water produced reinjected: This parameter determines the fraction of water produced after treatment that is reinjected into the reservoir. In the case of water flooding this fraction must be equal to 1.0 (the amount of water injected is more than the amount of water produced).
- Fraction of steam generation via co-generation: OPGEE allows the modeling of steam generation for thermal enhanced oil recovery with or without electricity co-generation. This parameter determines the share of steam generation via co-generation of electricity.

Processing practices Binary variables which represent the use of heater/treaters, stabilizer columns and gas processing units (AGR, dehydrator and demethanizer), the ratio of gas flared to oil produced, and the ratio of gas vented to oil produced. Some parameters are explained below.

User Inputs & Results 3.5

- Heater/treater: Binary variables (0 or 1) are used to determine the use of a heater/treater in the oil-water separation process. 1 is used to turn ON the heater/treater and 0 is used to turn OFF the heater/treater. More detailed choices for heater/treaters are made in the *'Surface Processing'* worksheet.
- Stabilizer column: Binary variables (0 or 1) are used to determine the use of a stabilizer column in the oil-gas separation process. 1 is used to turn ON the stabilizer column and 0 is used to turn OFF the stabilizer column. The stabilizer column is defined in section 3.4.2.2.
- Ratio of flaring to oil production: This is the ratio of gas flared to oil produced.
- Ratio of venting to oil production: This is the ratio of gas vented (not including operational venting or default leaks) to oil produced. **This ratio only includes venting used for gas disposal, as an alternative to flaring. It does not address normal operational vents and leaks**. Other default leaks are accounted in the *'Venting & Fugitives'* worksheet.

- Volume fraction of diluent: In some cases heavy crude is diluted after production using light hydrocarbons. This parameter determines the fraction of diluent or natural gas liquid (NGL) in diluted crude. The default case is the minimum NGL blend as determined by user inputs. The process model produces NGL in the demethanizer (if applicable), a fraction of which is blended as specified in the *'Surface Processing'* worksheet.

Land use impacts Parameters that determine the GHG emissions from land use change, including ecosystem carbon richness and relative disturbance intensity. *User Inputs & Results 3.6*

- Ecosystem carbon richness: Ecosystem carbon richness controls the amount of carbon emissions per unit of disturbed land, and varies from semi-arid grasslands (low potential carbon emissions) to forested (high potential carbon emissions).

- Field development intensity: The intensity of development can be chosen to be low, medium, or high. High intensity development resembles California thermal EOR operations, well production and injection wells are drilled on tight spacing. Low intensity development resembles conventional natural gas development or directional drilling from centralized drill pads, where the land disturbed per well is small.

Crude oil transport Parameters which determine transport modes and distances. This includes the fraction of crude oil transported by each mode of transport and the transport distance (one way) of each mode. The total fraction of all modes may exceed 1.0 because more than one transportation leg may be involved for transporting the crude oil from field to refinery. *User Inputs & Results 3.8*

Small emissions sources An added term to account for all emissions sources that are not explicitly included in OPGEE through calculations. Tables C.1 through C.7, as well as the *'Model Organization'* worksheet in OPGEE, describe which sources are explicitly included in the model. All sources that are not explicitly included are deemed to small to model, and are included in the small emissions sources term. *User Inputs & Results 3.9*

After entry into *'User Inputs & Results'*, values for key parameters are propagated to other worksheets as needed for calculations. Therefore, if a key parameter (such as API gravity) is to be changed, it **must** be changed on the front *'User Inputs & Results'* worksheet so that it is changed identically in all calculations.

OPGEE provides defaults for all required input parameters; these can be replaced with user inputs where data are available. In some cases, OPGEE calculates 'smart default' values dynamically based on user inputs for other parameters. For instance, the default flaring volume is determined from NOAA data based on the specified field location [13]. These smart defaults can also be overruled by user inputs.

			User	Default	Unit	Notes
49						
50	**3 User inputs - Conventional**					
51						
52	*Enter primary input parameters and choices*					
53						
54	3.1 Production methods					
55	Note: Enter "1" where applicable and "0" where not applicable					
56						
57	3.1.1 Downhole pump		0	1	NA	
58	3.1.2 Water reinjection		1	1	NA	If water flooding applies then "0"
59	3.1.3 Gas reinjection		0	1	NA	If gas flooding applies then "0"
60	3.1.4 Water flooding		0	0	NA	This is used for injecting amoun
61	3.1.5 Gas lifting	OK	1	0	NA	This is used for gas lifting
62	3.1.6 Gas flooding		0	0	NA	This is used for injecting a differ
63	3.1.7 Steam flooding		0	0	NA	This is used for injecting steam
64						
65	3.2 Field properties					
66	3.2.1 Field location (Country)	OK	Generic	Generic	NA	
67	3.2.2 Field name		Generic	Generic	NA	
68	3.2.3 Field age		35	35	yr	
69	3.2.4 Field depth		7240	7240	ft	
70	3.2.5 Oil production volume		1500	1500	bbl/d	
71	3.2.6 Number of producing wells		8	8	[-]	
72	3.2.7 Number of water injecting wells		4	4	[-]	
73	3.2.8 Well diameter		2.8	2.8	in	
74	3.2.9 Productivity index		3.0	3.0	bbl/psi-d	
75	3.2.10 Average reservoir pressure		1556.6	1556.6	psi	
76						
77	3.3 Fluid properties					
78	3.3.1 API gravity of produced crude		30	30	deg. API	
79	3.3.2 Associated gas composition					
80		N_2	2.3	2.0	mol%	Composition on dry basis
81		CO_2	0.3	6.0	mol%	
82		C_1	96.9	84.0	mol%	
83		C_2	[illegible]	[illegible]	mol%	

Introduction / Model Organization / Model changes / User Inputs & Results / Bulk Assessment / Energy Consumption / GHG Emissions / Exploration / Drilling & Development / Production & Extraction / St

Figure 2.3: User inputs section of the *'User Inputs & Results'* worksheet.

2.4.2 Secondary interaction

If more detailed data are available for a given oil production operation, and more specific estimates are desired, secondary interaction can be pursued by changing parameters on process-stage specific worksheets and supplementary worksheets.

It should not be necessary to change these secondary input parameters in basic use of OPGEE. The secondary parameters include parameters with less effect on the resulting emissions, that are not highly variable across operations, or that are less likely to be known by model users. Examples include compressor suction pressure and temperature, type of prime mover, or pump efficiency. Note that some of these parameters (e.g., pump efficiency) have significant effects on model results, but are not believed to be highly variable across fields (except in cases of especially old or poorly maintained equipment).

All secondary input parameters are free for the user to change in the input data sections of the process stage worksheets. Parameters that are classified as *User Locked* (see Figure 2.2 above) should not be changed because they are either calculated from other primary inputs or derived from the *'User Inputs & Results'* worksheet.

Figure 2.4 shows the input data section of the *'Production & Extraction'* worksheet. Moving left to right across the screen, features of interest include:

Parameters and sub-parameters In columns A through K, the names and descriptions of parameters and calculation results are numbered in a hierarchical fashion. Each parameter or calculation result has a unique number to allow ease of reference to the model. For example, in the Produced Water group of parameters and calculations (2.1.3), the water specific gravity (2.1.3.3) is calculated using the concentration of dissolved solids (2.1.3.2).

User and default columns Columns M and N include the user and default inputs for the production calculations. Column M is always used in the final calculations. Column N is included for reference, and includes default values. Before any user input is changed, all user values are equal to default values.

Free and locked cells As shown in Figure 2.2, *User Free* and *Default Free* cells are included with light tones, while *User Locked* and *Default Locked* cells are included with dark tones. For example, in Figure 2.4 the highlighted cell M40 represents the mol% of methane (C_1) in the associated gas. Because this quantity is a key input parameter and is defined on the *'User Inputs & Results'* worksheet, it is marked here as *User Locked*. Therefore, if the user wishes to change the gas composition, this should be done on the *'User Inputs & Results'* worksheet where gas composition is classified as *User Free*.

Units In column O, units are listed for all input parameters, variables, and calculation results (where applicable).

User and default reference Columns Q and S are spaces to record the data sources of input parameters. Where applicable, the source of the default value is listed

Box 2.2: Hints for using OPGEE without errors

1. Do not change formulas in *User locked* or *Default locked* cells, as these can result in mis-calculation;
2. Always check error reports in *'User Inputs & Results'* section 7.1 for errors before considering results final;
3. Use care to collect physically realistic and consistent data where default values will be overwritten (e.g., if depth of field is greatly increased, operating pressure will often increase as well);
4. To ensure reproducibility of results, document any sources for user inputs in the 'User Reference' column;
5. Save individual field assessments as separate worksheets to prevent incorrect propagation of changed cells.

in the *Default reference* column. If a user changes a parameter to a non-default value, they can place any desired information about the source (such as author, page, dataset, vintage, data quality, expected uncertainty, etc.) in the *User reference* column.

Notes To the right of the default reference column is the notes column (not shown, column Y). The *Notes* column contains explanatory notes or other information that may be useful to the user.

2.4.3 Checking for errors

It is possible to mistakenly enter data that are invalid, contradictory, or otherwise result in errors. In OPGEE, errors are checked at the bottom of the *'User Inputs & Results'* worksheet. Before reporting results from an OPGEE calculation, the user should check that no errors appear in the error check section.

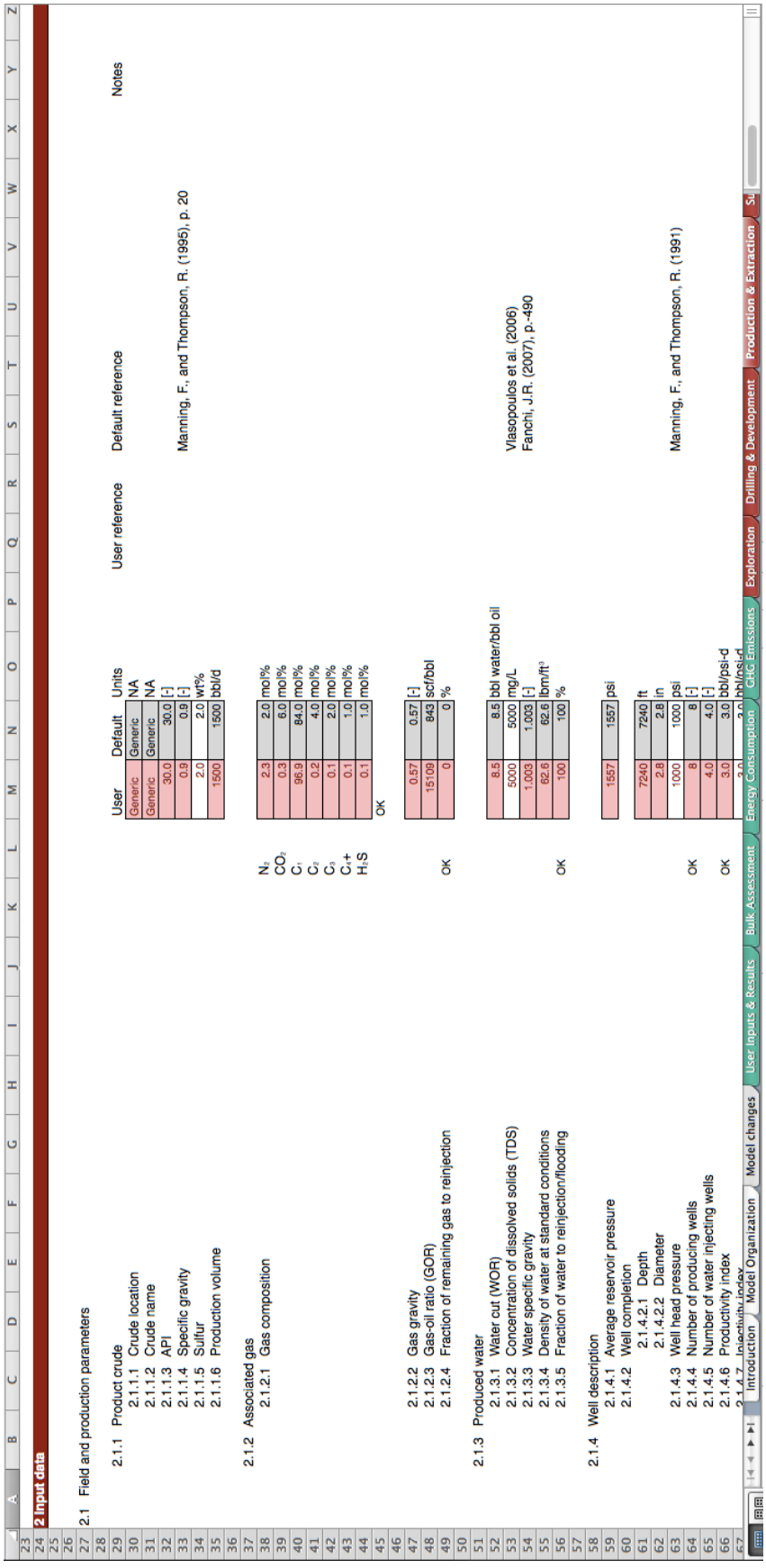
User Inputs & Results 3.10 & 7.1

A summary indicator for model errors is *'User Inputs & Results'* reported as the 'Overall error check.' An error found in the overall error check here can be traced to a particular worksheet and cell by examining the 'Specific error checks.' Specific error checks can be debugged by moving to the worksheet and cell in question and tracing any logical or inputs errors that have flagged that error check. Common sources of errors include logical errors in pathway selection (e.g., more than one mutually exclusive technology selected) and input errors (e.g., gas composition sums to more than 100 mol%).

User Inputs & Results 3.10

User Inputs & Results 7.1.1 - 7.1.25

Hints for using OPGEE without errors are given in Box 2.2.



		User	Default	Units	User reference	Default reference	Notes
2 Input data							
2.1 Field and production parameters							
2.1.1 Product crude		Generic	Generic	NA			
2.1.1.1 Crude location		Generic	Generic	NA			
2.1.1.2 Crude name		30.0	30.0	[-]			
2.1.1.3 API		0.9	0.9	[-]			
2.1.1.4 Specific gravity		2.0	2.0	wt%		Manning, F., and Thompson, R. (1995), p. 20	
2.1.1.5 Sulfur		1500	1500	bbl/d			
2.1.1.6 Production volume							
2.1.2 Associated gas							
2.1.2.1 Gas composition	N_2	2.3	2.0	mol%			
	CO_2	0.3	6.0	mol%			
	C_1	96.9	84.0	mol%			
	C_2	0.2	4.0	mol%			
	C_3	0.1	2.0	mol%			
	C_4+	0.1	1.0	mol%			
	H_2S	0.1	1.0	mol%			
		OK					
2.1.2.2 Gas gravity		0.57	0.57	[-]			
2.1.2.3 Gas-oil ratio (GOR)	OK	15109	843	scf/bbl			
2.1.2.4 Fraction of remaining gas to reinjection		0	0	%			
2.1.3 Produced water							
2.1.3.1 Water cut (WOR)		8.5	8.5	bbl water/bbl oil			
2.1.3.2 Concentration of dissolved solids (TDS)		5000	5000	mg/L		Vlasopoulos et al. (2006)	
2.1.3.3 Water specific gravity		1.003	1.003	[-]		Fanchi, J.R. (2007), p.-490	
2.1.3.4 Density of water at standard conditions		62.6	62.6	lbm/ft³			
2.1.3.5 Fraction of water to reinjection/flooding	OK	100	100	%			
2.1.4 Well description							
2.1.4.1 Average reservoir pressure		1557	1557	psi			
2.1.4.2 Well completion							
2.1.4.2.1 Depth		7240	7240	ft			
2.1.4.2.2 Diameter		2.8	2.8	in			
2.1.4.3 Well head pressure		1000	1000	psi		Manning, F., and Thompson, R. (1991)	
2.1.4.4 Number of producing wells	OK	8	8	[-]			
2.1.4.5 Number of water injecting wells		4.0	4.0	[-]			
2.1.4.6 Productivity index	OK	3.0	3.0	bbl/psi-d			
2.1.4.7 Injectivity index		2.0	2.0	bbl/psi-d			

Figure 2.4: Input data section of *'Production & Extraction'* worksheet.

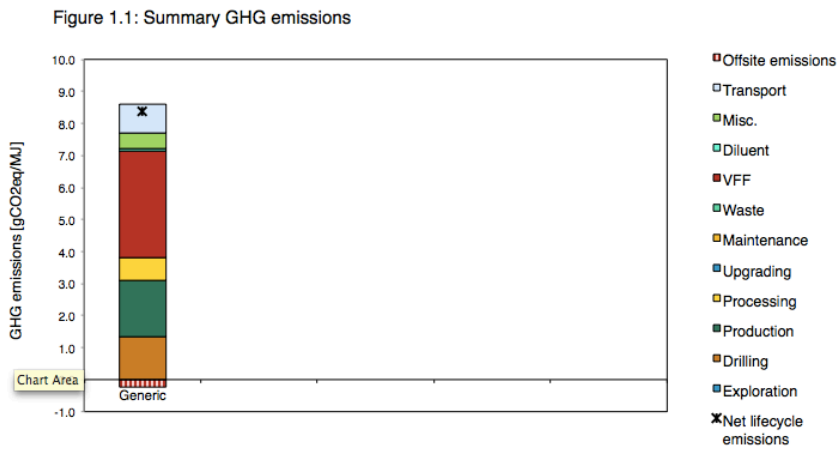


Figure 2.5: Graphical results for a 'Generic' crude oil. *'User Inputs & Results'* Figure 1.1.

2.4.4 Results

After the user enters data, OPGEE computes the resulting GHG emissions from that project. Emissions results are presented in tabular form in gCO_2 equivalent GHG emissions per MJ LHV crude oil delivered to the refinery gate.[2] Emissions are broken down by stage (generally) or by type, with fugitive emissions for all process stages summed together for convenient interpretation as 'VFF' emissions. Emissions are plotted in graphical form as well, with space for up to 5 comparative assessments. Total energy consumed per unit of energy delivered to the refinery gate is also presented in tabular and graphical form. These tabular and graphical results are illustrated in Figures 2.5 and 2.6.

User Inputs & Results Table 1.1

User Inputs & Results Figure 1.1

User Inputs & Results Table 1.2, Figure 1.2

[2]The heating value basis of the denominator crude oil can be changed so that emissions are calculated per MJ HHV of refinery input. This can be changed on the *'Fuel Specs'* worksheet. See discussion below in Section 6.4.

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	Generic				
Exploration	0.0				
Drilling	1.3				
Production	1.8				
Processing	0.7				
Upgrading	0.0				
Maintenance	0.0				
Waste	0.0				
VFF	3.4				
Diluent	0.0				
Misc.	0.5				
Transport	0.9				
Offsite emissior	-0.2				
Net lifecycle em	8.36				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 2.6: Tabular results for a 'Generic' crude oil. *'User Inputs & Results'* Table 1.1.

2.5 Bulk assessment

2.5.1 Introduction to bulk assessment

OPGEE has a built-in capability to analyze a number of fields or oil production projects and bookkeep the results for comparison and further analysis. The *'Bulk Assessment'* worksheet has a similar structure to the *'User Inputs & Results'* worksheet. However, the *'Bulk Assessment'* worksheet is expanded to allow multiple projects to be assessed in one computational run.

The bulk assessment capability is developed using a Microsoft VBA macro. In addition to running a number of fields in sequence, the bulk assessment machinery has a built-in feature to programmatically resolve errors that arise from input data inconsistencies. It also automates iterative calculations such as the reconfiguration of gas composition in the case of gas lift or setting gas export to zero by incrementally increasing gas reinjection.

2.5.2 Using the bulk assessment tool

At the top of the *'Bulk Assessment'* worksheet the user enters the number of fields to be assessed. In the input data section the user enters available data for each assessed field. When limited datasets are available, the bulk assessment macro will complete the datasets by filling required inputs with defaults and smart defaults where applicable. The results are generated for all fields in one computational run. The bulk assessment machinery is run by pressing the "Run Assessment" command button.

Bulk Assessment 1.1-1.9

Bulk Assessment 1.10

2.5.3 Bulk assessment macro description

Figure 2.7 shows the outer structure of the bulk assessment macro. For every field under study, the macro first copies user entries into the model front worksheet (*'User Inputs & Results'*). Then checks for empty user entries. For every empty user input, the macro copies the default value from the model front worksheet. In the case of 0 entry for number of producing wells, a warning appears and prompts the user to enter a valid number of producing wells. When the data set of the field under study is complete, the macro copies the complete set of data into the model front worksheet, initiates errors fixing and entry adjustments procedure, and returns the completed and corrected/adjusted set of data into the bulk assessment worksheet. Finally the macro copies the full data set back into the front worksheet and returns the output into the bulk assessment worksheet. The same process is repeated for each field under study.

The bulk assessment machinery is capable of fixing errors, performing iterative calculations and adjusting input parameters where necessary. It is not practical to perform these computational tasks manually when assessing a large number of projects (100+). The built-in macro ensures consistent treatment across all fields. Errors that are addressed in the macro include:

- Discrepancies between country-average default flaring rate and entered GOR (e.g., flaring module predicts more flaring than field has gas available);
- Discrepencies between default fugitive emissions of gaseous components and gas available from production;
- Requirement to iteratively solve for the gas composition in the wellbore in the case of gas lift;
- Error with productivity index resulting in negative bottomhole pressures;
- Error resulting from very large frictional lifting penalties due to too-small default wellbore diameter;
- Requirement to iteratively solve for gas reinjected to result in 0 gas export.

Appendix D details the functioning of these error correction features.

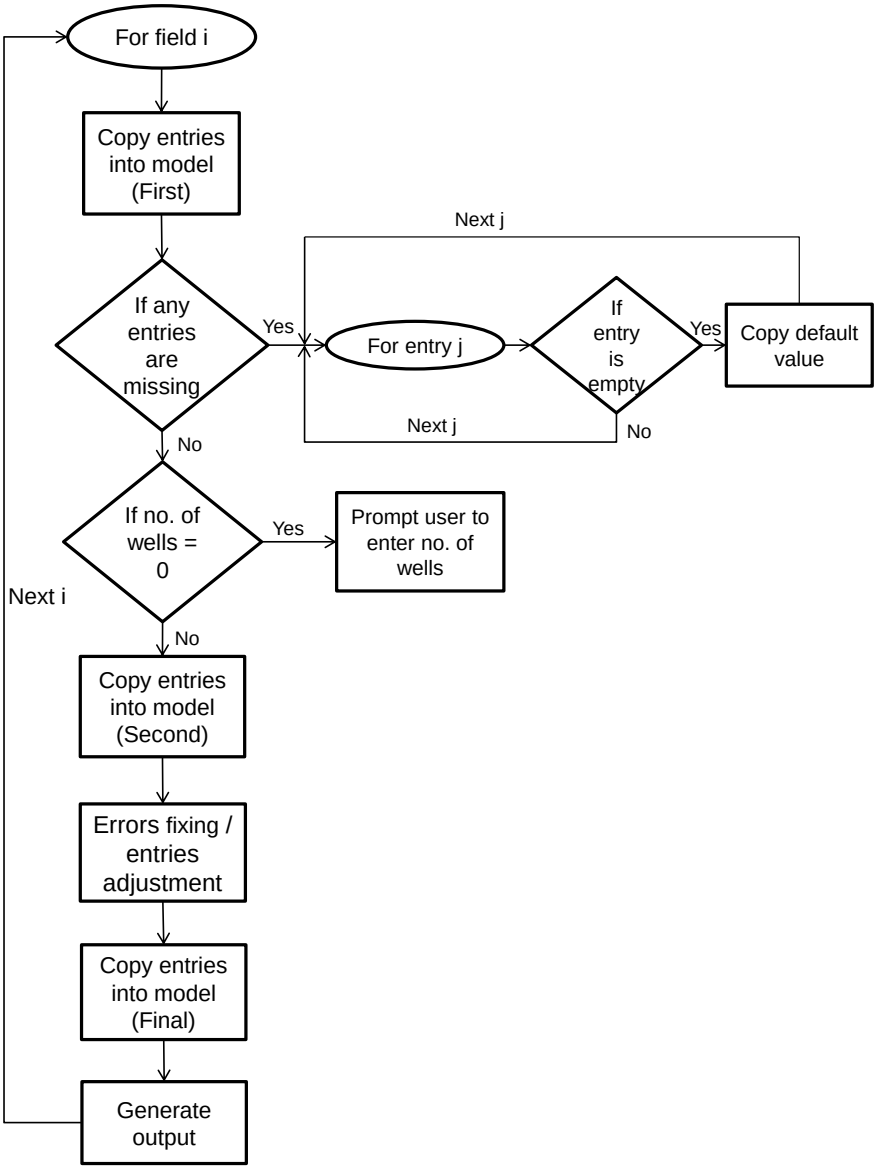


Figure 2.7: The overall structure of the bulk assessment macro.

Part II

Technical documentation

3 Process stage worksheets

This section explains the main assumptions and calculations for each process stage worksheet. Items discussed include user assumptions and choices, process calculation assumptions, calculations of input parameters, and calculations of intermediate outputs.

3.1 Exploration emissions

3.1.1 Introduction to petroleum exploration

Emissions from petroleum exploration occur during clearing of land for seismic surveys, operation of seismic survey equipment, drilling of exploratory wells, and from fugitive emissions during drilling operations. Offsite emissions occur due to other materials and services consumed during drilling (e.g., computing energy consumed during seismic data processing). A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.1.

3.1.2 Calculations for petroleum exploration

Because petroleum exploration emissions only occur at the outset of production, they are likely to be very small when amortized over the producing life of an oil field. For this reason, emissions from exploration are considered below the significance cutoff in the OPGEE v1.1.

3.1.3 Defaults for petroleum exploration

Because exploration activities are believed to be below the significance cutoff, modeled exploration emissions default to 0 gCO_2/MJ. Therefore, any exploration emissions are assumed to be part of the small emissions sources term.

User Inputs & Results 3.9

3.2 Drilling & development

3.2.1 Introduction to drilling & development

Drilling and development operations result in a variety of emissions. Well drilling and installation of production equipment results in on-site energy use (e.g., for rigs and other construction equipment) as well as indirect offsite energy use (e.g., embodied energy consumed to manufacture well casing). Drilling and development also results in land use impacts, which can release biogenic carbon from disturbed ecosystems [75]. In addition, fugitive emissions can occur during the drilling process. A list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.2.

3.2.2 Calculations for drilling & development

Two aspects of field drilling and development are modeled in OPGEE v1.1: drilling energy consumption and land use impacts. Other emissions from drilling and development are not explicitly modeled and therefore would be accounted for in the small sources term. The parameters and variables used in the drilling and development model equations are listed in Table 3.3.

User Inputs & Results 3.9

3.2.2.1 Emissions from drilling

Drilling oil wells consumes fuel. This fuel is consumed on site in prime movers (generally diesel engines) for a variety of purposes: to power mud pumps; apply torque to drill string; pull drill string; raise, lower and retrieve subsurface monitoring equipment; and pump cement. The amount of fuel consumed per unit of depth drilled increases as a well gets deeper, due to slower drilling progress with depth.

Relationships for these functions are from Brandt [76]. Data from Canadian drilling operations are collected for the years 2000, 2001, 2002, and 2005 [77–79]. True drilling depth (not vertical depth) is related to amount of fuel consumed per well. An exponential relationship is found between drilling depth and fuel use (see Figure 3.1). High and low energy consumption curves are fit to these data:

Drilling & Development 1.2.2

$$e_{DR} = a_{DR} \exp\left(b_{DR} h_W\right) \qquad \text{[mmBtu/1000 ft]} \tag{3.1}$$

where e_{DR} = depth-specific drill rig energy intensity [mmBtu/1000 ft]; a_{DR} = drill rig energy intensity scaling constant [mmBtu/1000 ft]; b_{DR} =drill rig energy intensity growth constant [1/1000 ft]; and h_W = true well depth (not vertical depth) [1000 ft]. When fitting this equation to high and low-intensity drilling data, fits are of moderate predictive ability (R^2 = 0.708 for low intensity, 0.589 for high intensity).

Drilling energy consumption must be amortized over the producing life of a well. Also, drilling and development energy must account for drilling of

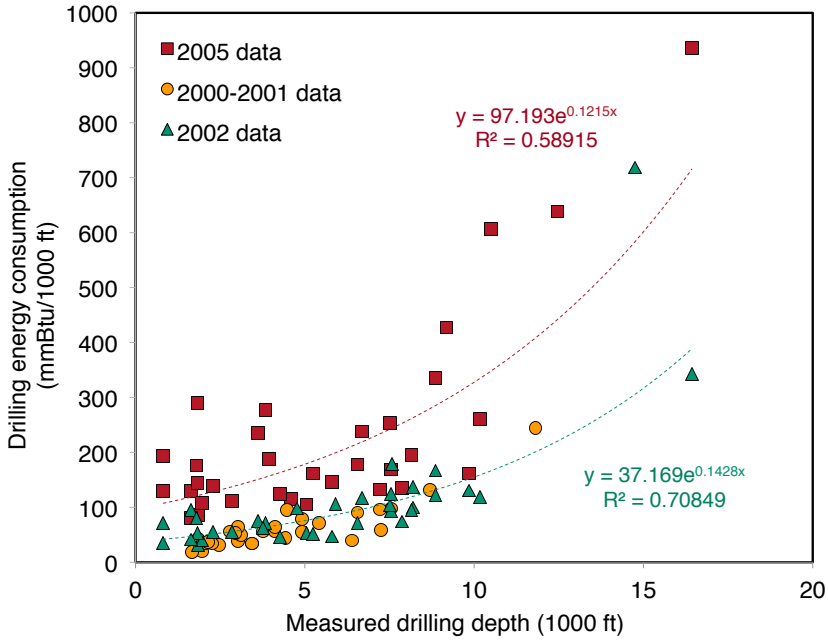


Figure 3.1: Drilling energy intensity as a function of well depth as measured for Canadian drilling operations.

water injection wells. The lifetime productivity of wells varies by orders of magnitude, depending on the quality of the oil reservoir and its size. In order to obtain a central estimate for the productivity of a well, we use historical data from California.

California reports the number of producing and shut-in wells, with ≈ 100,000 wells counted in recent years [75]. However, these datasets do not include:

- Wells that are fully abandoned and therefore not classed as "shut-in",
- Wells that were drilled and plugged in abandoned fields,
- Wells that were drilled before 1915, when reporting began.

To address these shortcomings, wells drilled on a yearly basis were compiled from the California Department of Oil, Gas, and Geothermal Resources (DOGGR) annual reports [80]. Production and injection wells drilled per year are compiled from 1919-2005, while exploration wells drilled per year are compiled from 1926 to 2005 (exploratory wells were not reported before 1926). Total exploratory and production/injection drilling activity over these years was equal to 188,508 wells. Due to missing wells (early exploratory wells, all wells prior to 1919, other missing wells) we assume total wells drilled ≈ 200,000. Cumulative production in the entire state of California was ≈ 25.99 Gbbl at the end of 2005. Therefore, average oil produced per well drilled was ≈ 130,000 bbl/well.

Drilling & Development 1.3.1

The energy intensity of drilling per unit of energy produced is therefore calculated as follows:

Drilling & Development 1.4

$$ei_{DR} = \frac{e_{DR} h_W}{Q_{o,tot} LHV_o} \qquad \text{[mmBtu/mmBtu]} \tag{3.2}$$

where ei_{DR} = energy intensity of drilling [mmBtu/1000 ft]; h_W = average well depth [1000 ft]; $Q_{o,tot}$ = total lifetime productivity per well drilled [bbl oil/well]; and LHV_o = lower heating value of the crude produced [mmBtu LHV/bbl].

The energy intensity of drilling tends to be small when amortized over total well productivity, with default values on order 10^{-4} to 10^{-3} mmBtu/mmBtu.

3.2.2.2 Emissions from land use impacts

Land use impacts during drilling and field development are included in OPGEE for three categories: soil carbon that is oxidized upon disturbance of land, biomass carbon that is oxidized biomass disturbance, and emissions from foregone sequestration, due to the fact that biomass carbon sequestration is slowed on cleared land. For each of these impacts, emissions estimates from Yeh et al. [75] are included. Yeh et al. measured impacts over a 150 year period, which is not in alignment with other analyses that use 30 year land use impact calculations. For this reason, calculations from Yeh et al. were modified to reduce the timeframe for analysis to 30 years, reducing the amount of regrowth possible [81].

Drilling & Development 2.1 - 2.4

Emissions Factors Tables 1.5, 1.6

The user has the option to choose a 30 year or 150 year analysis timeframe. The default analysis timeframe is set to 30 years.

Drilling & Development 2.1.6

In order to estimate land use GHG emissions, three settings are required. First, the crude production method must be chosen. The options for crude production method include conventional production via wellbore (primary, secondary, and tertiary recovery of conventional and heavy hydrocarbons, including in situ recovery of bitumen) and mining-based production of bitumen.

Drilling & Development 2.1.3

Next, the carbon richness of the ecosystem is specified. Options include low, moderate, and high carbon richness. Low carbon richness estimates are derived from California production in the semi-arid to arid central valley of California [75]. The high carbon richness estimates are derived from forested regions in Alberta (e.g., rocky mountain foothills) [75]. Moderate carbon richness is considered a mixed ecosystem with carbon richness between these ecosystems.

Drilling & Development 2.1.4

Lastly, the intensity of field development must be specified. High intensity field development corresponds to high fractional disturbance, such as in a field drilled on tight spacing. Low intensity field development corresponds to a sparsely developed field with little fractional disturbance. Moderate field development occurs between these two extremes. Work by Yeh et al. [75] can be consulted for satellite images of low and high field development intensity.

Drilling & Development 2.1.5

Emissions associated with each choice are shown in Table 3.2 in units of gCO_2eq GHGs per MJ of crude oil produced. Land use emissions from oil

Emissions Factors Tables 1.5, 1.6

Table 3.1: Land use GHG emissions for 30 year analysis period from field drilling and development in OPGEE for conventional oil operations [g CO_2 eq./MJ of crude oil produced]. Data from Yeh et al. (2010).

	Low carbon stock (semi-arid grasslands)			Moderate carbon stock (mixed)			High carbon stock (forested)		
	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.
Soil carbon	0.03	0.13	0.35	0.22	0.57	1.93	0.40	1.01	3.51
Biomass	0.00	0.00	0.00	0.34	0.68	1.47	0.68	1.36	2.94
Foregone seq.	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02

Table 3.2: Land use GHG emissions for 150 year analysis period from field drilling and development in OPGEE for conventional oil operations [g CO_2 eq./MJ of crude oil produced]. Data from Yeh et al. (2010).

	Low carbon stock (semi-arid grasslands)			Moderate carbon stock (mixed)			High carbon stock (forested)		
	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.
Soil carbon	0.03	0.13	0.35	0.10	0.35	1.50	0.16	0.57	2.65
Biomass	0.00	0.00	0.00	0.01	0.09	0.33	0.02	0.17	0.65
Foregone seq.	0.00	0.00	0.00	0.02	0.03	0.05	0.03	0.05	0.09

sands operations are tracked separately on the *'Bitumen Extraction & Upgrading'* worksheet (see Section 3.8).

3.2.3 Defaults for drilling & development

Default values for drilling & development calculations are shown in Tables 3.3 and 3.2.

Table 3.3: Default inputs for drilling calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
a_{DR}	Drill rig energy consumption constant	-	37.169	37.169 - 97.193	[mmBtu/1000 ft]	[76]	a
b_{DR}	Drill rig energy consumption increase rate	-	0.1428	0.1215 - 0.1428	[1/1000 ft]	[76]	b
h_W	Well depth (true drilling depth)	-	$=h$	0.5 - 25	[1000 ft]	-	c
Q_{ot}	Total cumulative production per well over life of well	-	130,000	Unknown	[bbl/well]	[80, 82]	d
LHV	Lower heating value of crude oil	-	5.51	5.15 - 6.18	[mmBtu/bbl]	[83]	e

[a] Low and high drilling efficiency constants found from fitting data. Default set to low intensity.
[b] Exponential increase with drilling depth. Low intensity drilling actually has slightly higher growth rate.
[c] Default well depth chosen to be depth of field h. Range of field depths is large in practice.
[d] Cumulative production per well in California equals 130,000 bbl/well to the end of 2005.
[e] Higher heating value of crude depends on density and composition.

3.3 Production & extraction

3.3.1 Introduction to production & extraction

The production and extraction process transports reservoir fluids from the subsurface reservoir to the surface. Emissions from crude oil production and extraction mainly occur from fuel combustion for lifting and injection drivers, with other smaller sources such as fugitive emissions from wellbores.

The reservoir is the source of fluids for the production system. It can also furnish energy for production. In many cases, the reservoir is unable to furnish sufficient energy to produce fluids to the surface at economic rates throughout the life of the reservoir. When this occurs, artificial lift equipment is used to enhance production rates by adding energy to the fluids. Energy can be supplied to the fluids through a subsurface pump (e.g., downhole pump). Or, producers can reduce the back pressure on the reservoir with surface compression equipment that allows lower wellhead pressure. Also, producers can inject gas into the production string to reduce the flowing gradient of the fluid (i.e., gas lift) [41, p. 1].

In addition to artificial lifting, water can be injected into the reservoir to support reservoir pressure and increase oil recovery. Recovery is increased by maintaining reservoir pressure and by physically displacing oil with water from near injection wellbores to production wellbores [57, p. 1]. Tertiary recovery technologies (also known as enhanced oil recovery [EOR]) include gas flooding and steam injection.

Most common artificial lifting and improved oil recovery techniques are included in OPGEE. These include: downhole pump, gas lift, water flooding, gas flooding, and steam injection. In the *'User Inputs & Results'* worksheet the user is prompted to choose a combination of techniques applicable to the modeled operation. Some techniques are not built in the current version of OPGEE, including CO_2 flooding and hydraulic fracturing (also known as "fracking"). These modules will be added in the future.

A complete list of emissions sources from production, along with their estimated magnitude, is shown in Table C.3. A list of all of the equation parameters and their default values (if applicable) and sources is included in Table 3.5.

3.3.2 Calculations for production and extraction

Energy for lifting is required to overcome the pressure traverse, i.e., the pressure drop between the subsurface reservoir and the surface wellhead. The pressure traverse arises due to two factors: (i) flow against gravity, and (ii) frictional losses. The pressure required for lifting is calculated by adding the wellhead pressure to the pressure traverse and subtracting the wellbore pressure. The artificial lifting methods that can be chosen in OPGEE are: (i) downhole pump, and (ii) gas lift. The pressure required for lifting is equal to the

discharge pressure of the downhole pump. The power required to generate the required discharge pressure depends on the discharge flow rate and pump efficiency. Finally the energy required to drive the pump is calculated based on the power requirement (expressed as brake horsepower).

The calculation of the energy required in water injection- and gas injection-based enhanced oil recovery uses the user inputs for injection volume and discharge pressure. Smart defaults are in place to help assign the discharge pressure taking into account the well depth and frictional losses.

The energy required for steam flooding requires rigorous modeling of steam generation. An additional complexity is caused by the modeling of electricity co-generation. This is explained in Section 4.2.

In the case of gas lift, if the user enters the volume of gas injected and the discharge pressure, OPGEE will compute the compression energy. However, OPGEE is not sensitive to changes in the gas lift, i.e. the dynamics between the volume of gas lift and the lifting head are not considered. The calculation of these dynamics is beyond the scope of a linear GHG estimator. This requires a two phase flow model, which is not included in OPGEE v1.1.

Default values for production and extraction calculations are shown in Table 3.5.

3.3.2.1 *Oil specific gravity*

The specific gravity of crude oil is usually reported as API gravity, measured at 60 °F. The API gravity is related to the specific gravity γ_o by:

Production & Extraction 2.1.1.4

$$^{\circ}\text{API} = \frac{141.5}{\gamma_o} - 131.5 \qquad [\text{-}] \tag{3.3}$$

where API gravity and γ_o are dimensionless measures. The specific gravity is the ratio of the density of the liquid to the density of water at 60 °F [71, p. 478].

3.3.2.2 *Gas specific gravity*

The specific gravity of associated gas is calculated using air density at standard conditions with [84, p. 10]:

Production & Extraction 2.1.2.2

$$\gamma_g = \frac{\rho_{gsc}}{\rho_{asc}} \qquad [\text{-}] \tag{3.4}$$

where ρ_{gsc} = gas density at standard conditions [lbm/ft^3]; and ρ_{asc} = air density at standard conditions [lbm/ft^3]. Standard conditions refers to the temperature and pressure required to specify 1.0 scf (60 °F and 14.7 psia) [47, p. 35]. Accordingly, the gas density at standard conditions is calculated using:

$$\rho_{gsc} = \frac{p_b \text{MW}_g}{\text{R}T_b} \qquad \left[\frac{\text{lbm}}{\text{ft}^3}\right] \tag{3.5}$$

where MW_g = molecular weight of the associated gas mixture [lbm/lbmol]; p_b = base pressure [psia]; and T_b = base temperature [°R]; R = gas constant [ft^3-psia/lbmol-°R]. The molecular weight is calculated from the molecular weights and molar fractions of the gas constituents.

3.3.2.3 *Water specific gravity*

The specific gravity of produced water at standard conditions can be estimated with [42, p. I-481]:

Production & Extraction 2.1.3.3

$$\gamma_w = 1 + C_{sd} 0.695 \times 10^{-6} \qquad [-] \tag{3.6}$$

where C_{sd} = concentration of dissolved solids (also known as TDS) [mg/L]. The constant 0.695×10^{-6} has units of [L/mg].

3.3.2.4 *Gas compression ratio*

The total gas compression ratio is calculated using:

$$R_C = \frac{p_d}{p_s} \qquad [-] \tag{3.7}$$

where P_d = discharge pressure [psia]; and P_s = suction pressure [psia].

If ratio R_C is more than 5 to 1, two or more compressor stages will be required [71, p. 295]. The compression of gas generates significant amount of heat, but compressors can only handle a limited temperature change. Multiple stage compressors allow cooling between stages making compression less adiabatic and more isothermal. The same compression ratio is ideally used for each stage. Each stage has the same ratio if the compression ratio per stage is the Nth root of the total compression ratio, when N = number of stages:

Production & Extraction 2.4.1.3

$$\text{If } \frac{p_d}{p_s} < 5, \text{ then } R_C = \frac{p_d}{p_s}, \text{ otherwise if } \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}} < 5, \text{ then } R_C = \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}}, \ldots \tag{3.8}$$

where p_d = discharge pressure [psia]; and p_s = suction pressure [psia].

The number of stages is determined from the calculation of the compression ratio, as shown in eq. (3.8). OPGEE allows a maximum of 5 stages of compression.

3.3.2.5 *Gas compressor suction temperature*

When multiple stage compressors are used the gas must be cooled between stages to reduce the adiabatic work of compression. The discharge temperature of the compressor is calculated as [55, p. 105]:

$$\frac{T_d}{T_s} = \left(\frac{p_d}{p_s}\right)^{\left[\frac{\left(C_{p/v}-1\right)}{C_{p/v}}\right]} \qquad [-] \tag{3.9}$$

where T_d = discharge temperature [°R]; T_s = suction temperature [°R]; and $C_{p/v}$ = ratio of specific heats at suction conditions. Ideal gas behavior (i.e., gas compressibility factor (Z)= 1) is assumed.

The suction temperature of the subsequent compressor is estimated assuming 80% interstage cooling (imperfect cooling) so that:

Production & Extraction 2.4.1.6

$$T_{s2} = \lambda_{\Delta T} \left(T_d - T_s\right) + T_s \qquad [^\circ\mathrm{R}] \tag{3.10}$$

where T_{s2} = suction temperature of stage 2 compressor [°R]; and $\lambda_{\Delta T}$ = fraction of temperature increase remaining after cooling, 0.2 [fraction]. The default of ≈80% interstage cooling is taken from an example of imperfect cooling in [85, Table 7].

3.3.2.6 Well pressure traverse

The pressure traverse is the total pressure required to lift the crude oil mixture against gravity and overcome friction and kinetic losses. This is equal to the pressure drop along the well tubing from the wellbore to the wellhead which has two main components: (i) the elevation component, which is the pressure drop due to gravity; and (ii) the friction component, which is the pressure drop due to liquid contact with the inner walls of the well tubing.

The first step in the estimation of the pressure traverse is the calculation of the total head as:

Production & Extraction 3.1.1

$$h_{tot} = h_{el} + h_f \qquad [\mathrm{ft}] \tag{3.11}$$

where h_{tot} = total head [ft]; h_{el} = well depth [ft]; and h_f = friction head [ft]. The friction head is calculated using the Darcy formula [71, p. 447]:

Production & Extraction 3.1.1.2

$$h_f = \frac{f h_{el} v_{l,W}^2}{2 D_P g_c} \qquad [\mathrm{ft}] \tag{3.12}$$

where f = Moody friction factor [-]; h_{el} = well depth [ft]; $v_{l,W}$ = pipeline flow velocity [ft/s]; D_P = pipeline diameter [ft]; and g_c = gravitational constant, 32.2 [lbm-ft/lbf-s^2]. Frictional pressure losses in oil wells are usually rather low compared to the elevation pressure drop. In wells producing medium to high liquid rates, frictional drops amount to a maximum of 10% of the total pressure drop. This number increases for extremely high liquid rates [84, Section 2.5.3.1.3]. A major determinant of friction losses is the pipeline diameter or well tubing diameter (D_P). API and ISO are the international standards for products intended for worldwide use in the petroleum and natural gas industry. API tubing sizes range from outer diameters of 1.050 to 4.500 in. For high-rate wells, tubing larger than 4.5 in. may be beneficial [41, p. 106].

A Moody friction factor chart is shown in Figure 3.2 [86]. In laminar flow f varies with Reynold's Number (NRe). In turbulent flow f varies with NRe and the roughness of the pipeline [71, p. 481]. Table 3.4 shows the NRe ranges of different flow patterns.

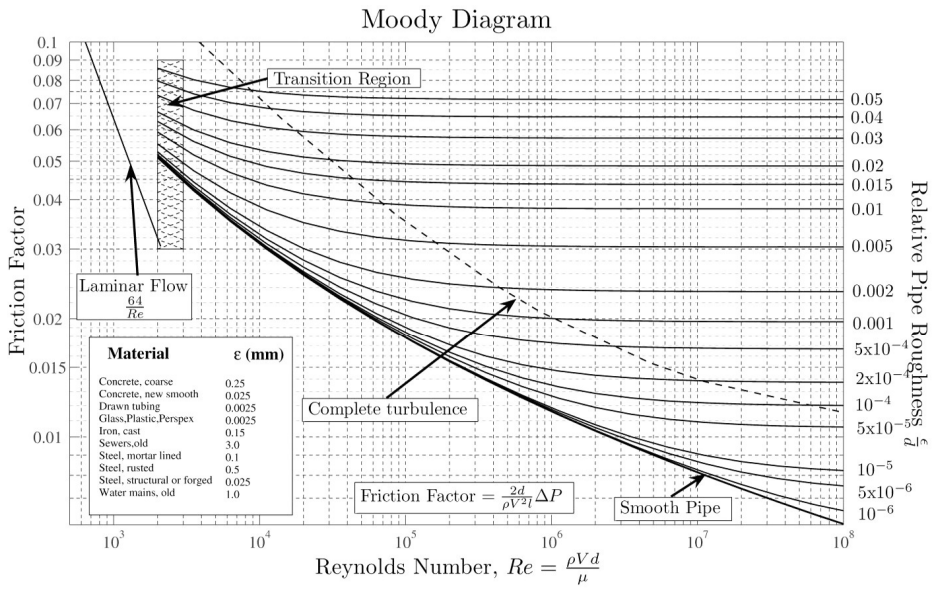


Figure 3.2: Moody friction factor chart [86].

The Moody friction factor is estimated using simplifications for the default case as follows. Water and oil are assigned viscosities of 1 and 10 cP, respectively. The viscosity of the oil-water mixture is assigned the volume-weighted viscosity of the two fluids.[1]

Reynolds number Nre is calculated as follows [87, p. 46]:

$$\text{Nre} = \frac{1.48 Q_l \rho_l}{D_P \mu_l} \tag{3.13}$$

where Q_l is the total liquid production rate [bbl/d]; ρ_l is the liquid density (oil-water mixture) [lbm/ft^3]; D_P is the wellbore production diameter [in], and μ_l is the fluid viscosity [cP]. Roughness of commercial steel of 0.0018 in is assumed [88], for a relative roughness r of 0.0006. The approximate friction factor can be calculated as [88, p. 625]:

$$f = \left(\frac{-1}{1.8 \log\left(\left[\frac{6.9}{\text{Nre}}\right] + \left[\frac{r}{3.7}\right]^{1.11} \right)} \right)^2 \tag{3.14}$$

This equation gives a friction factor f of 0.02 for default conditions. The friction factor is a user input on the *'Production & Extraction'* worksheet and can be adjusted based on the flowing fluids velocity.

[1]This simplification does not account for the complexity of oil-water mixture viscosity, but is used as a first-order approximation. Heavy oil can have very high viscosities as well.

Table 3.4: Reynold's Number ranges of different flow patterns. Data from McAllister (2009).

Flow pattern	NRe [-]
Laminar flow	NRe<2000
Transition flow	2000≤NRe≤4000
Turbulent flow	NRe> 4000

The pipeline flow velocity is calculated as:

$$v_{l,W} = \frac{Q_{l,W}}{A_P} \qquad [\text{ft/s}] \tag{3.15}$$

where $Q_{l,W}$ = wellbore flow rate or liquid production per well [ft^3/s]; and A_P = the cross sectional area of the pipe [ft^2]. The wellbore flow rate is calculated as:

Production & Extraction 3.1.1.2

$$Q_{l,W} = \frac{Q_l}{N_W} \qquad [\text{ft}^3/\text{s}] \tag{3.16}$$

where Q_l = total rate of liquid production [ft^3/s]; and N_W = number of producing wells. The total rate of liquid production is calculated as:

$$Q_l = Q_o(1 + \text{WOR}) \qquad [\text{ft}^3/\text{s}] \tag{3.17}$$

where Q_o = total rate of oil production [bbl/d]; WOR= water-to-oil ratio [bbl/bbl]. The total rate of liquid production is converted from [bbl/d] to [ft^3/s].

A column of fresh water at 60 °F exerts a gradient of ≈0.43 psi/ft [57, p. 25]. For brackish water, or to account for temperature, this gradient is multiplied by the specific gravity of the mixture at a given temperature. Accordingly the pressure traverse is estimated using the total head as [71, Table 1, p. 455]:

Production & Extraction 3.1.1.1

$$p_{trav,tot} = 0.43 h_{tot} \gamma_l \qquad [\text{psi}] \tag{3.18}$$

where $p_{trav,tot}$ = total pressure traverse [psi]; 0.43 = fresh water gradient at 60 °F [psi/ft]; $h_{tav,tot}$ = total head [ft]; and γ_l = the specific gravity of the crude oil mixture [-], calculated as:

$$\gamma_l = \gamma_o \lambda_o + \gamma_w \lambda_w \qquad [\text{-}] \tag{3.19}$$

where γ_o = the specific gravity of oil [-]; γ_w = the specific gravity of water [-]; λ_o = fraction of oil [fraction]; and λ_w = fraction of water [fraction]. The fraction of oil is calculated as:

$$\lambda_o = \frac{Q_o}{Q_o(1 + \text{WOR})} \qquad [\text{-}] \tag{3.20}$$

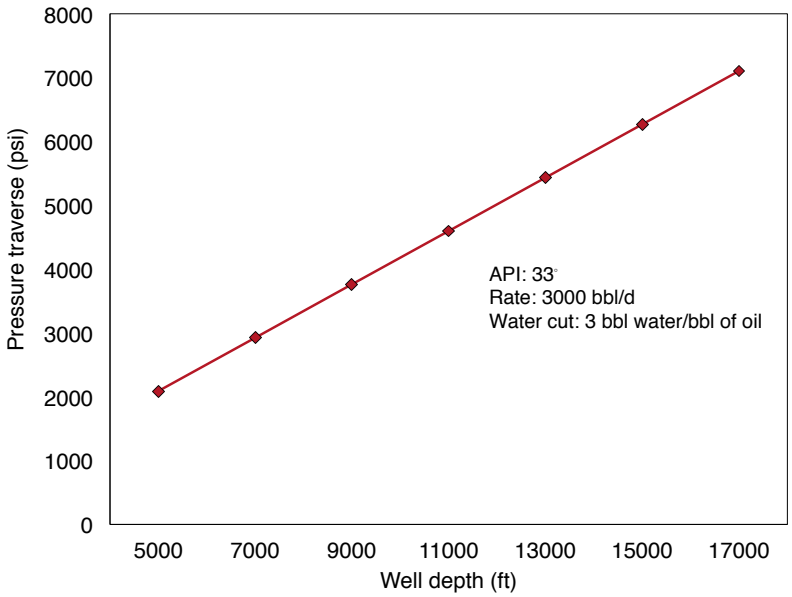


Figure 3.3: An example of a linear pressure traverse curve (GLR= 0).

The elevation component of the pressure traverse is estimated using a linear one phase flow model where the gas-to-liquid ratio is equal to zero (GLR= 0) and the temperature and pressure effects are ignored. Figure 3.3 shows an example of a linear pressure-traverse curve for a particular production rate and fluid properties. The slope of the curve is the relative density of the flowing oil-water mixture. For GLR>0 the relationship becomes non-linear and the pressure traverse becomes less sensitive to changes in the well depth with increasing GLR [41, Fig 1.12]. However, the generation of a non-linear relationship requires the application of the multi-phase flow correlations which requires an iterative, trial-and-error solution to account for the changes in flow parameters as a function of pressure. Due to the complexity of this approach, this is not implemented in the OPGEE v1.1.

3.3.2.7 Pressure for lifting

The second step after estimating pressure traverse is the calculation of the pressure for lifting which is the pressure required by artificial means (e.g., pump) to lift the oil-water mixture to the surface at the desired wellhead pressure. The pressure for lifting is calculated as:

Production & Extraction 3.1.2

$$p_{lift} = (p_{trav,tot} + p_{wh}) - p_{wf} \qquad \text{[psi]} \tag{3.21}$$

where p_{lift} = pressure for lifting [psi]; $p_{tav,tot}$ = total pressure traverse [psi]; p_{wh} = wellhead pressure [psi]; and p_{wf} = bottomhole pressure [psi]. The wellbore pressure is calculated from the average reservoir pressure by subtracting

the pressure drawdown. The pressure drawdown is the difference between the reservior pressure and the bottomhole pressure. This pressure drawdown causes the flow of reservoir fluids into the well and has the greatest impact on the production rate of a given well [84, p. 23].

$$\mathrm{PI} = \frac{Q_{l_W}}{(p_{res} - p_{wf})} \qquad \left[\frac{\text{bbl liquid}}{\text{psi-d}}\right] \tag{3.22}$$

where PI = well productivity index [bbl liquid/psi-d]; Q_{l_W} = liquid production per well [bbl liquid/d]; p_{res} = average reservior pressure [psi]; and p_{wf} = wellbore pressure [psi]. The increase in production requires an increase in pressure drawdown at a constant productivity index. In OPGEE a default productivity index of 3.0 [bbl liquid/psi-d] is assumed to calculate the pressure drawdown. The user has to control the inputs to satisfy the condition of $p_{wf} \geq 0$.

The pressure for lifting can either be applied by a downhole pump or by gas injection into the production string. The latter technique is known as gas lift. In some wells both a downhole pump and gas lift is used where the injected gas reduces the flowing gradient of the fluid.

3.3.2.8 Pump brake horsepower

The input horsepower to a pump is stated in terms of brake horsepower (BHP). The input is greater than the output because of pump efficiency. The brake horsepower is calculated using the pump discharge flow rate and the pumping pressure as [57, p. 27]:

Production & Extraction 3.1.3

$$\mathrm{BHP}_P = \frac{1.701 \times 10^{-5} Q_d \Delta p}{\eta_P} \qquad [\text{hp}]$$

This is broken down to:

$$\mathrm{BHP}_P\,[\text{hp}] = \frac{\frac{1[\text{hp}]}{1714[\text{gpm-psi}]} \frac{42\left[\frac{\text{gal}}{\text{bbl}}\right]}{24\left[\frac{\text{hr}}{\text{d}}\right]60\left[\frac{\text{min}}{\text{hr}}\right]} Q_d \left[\frac{\text{bbl}}{\text{d}}\right] \Delta p[\text{psi}]}{\eta_P} \tag{3.23}$$

where BHP_P = brake horsepower [hp]; Q_d = pump discharge rate [bbl/d]; Δp = pumping pressure [psi]; and η_P = pump efficiency [%]. The term 1714 is a dimensionless factor that converts between [hp] and [gpm-psi]. The pumping pressure is the difference between pump discharge and suction pressures. The default suction pressure is 0 [psi]. In the case of a downhole pump the pumping pressure is equal to the pressure for lifting as calculated in eq. (3.21).

3.3.2.9 Compressor brake horsepower

In determining compressor horsepower, the conventional compressor equation apply. For multi-stage compressors, horsepower calculations are made for each stage and summed to determine the required driver size. For assumed

reciprocating compressors, the ideal isentropic horsepower is calculated using [55, p. 105]:

Production & Extraction 3.3.1-3.3.5

$$-W_N = \left\{ \frac{C_{p/v}}{(C_{p/v} - 1)} \right\} \left(3.027 \cdot \frac{14.7}{520} \right) T_s \left\{ \left(\frac{p_d}{p_s} \right)^{\frac{(C_{p/v}-1)}{C_{p/v}}} - 1 \right\} \qquad \left[\frac{\text{hp-d}}{\text{MMscf}} \right] \tag{3.24}$$

where W_N = adiabatic work of compression of Nth stage [hp-d/MMscf] (-W denotes work output); $C_{p/v}$ = ratio of specific heats [-]; T_s = suction temperature [°R]; p_s = suction pressure [psia]; and p_d = discharge pressure [psia]. The constant 3.027 has a unit of [hp-d/MMscf-psia]. The base temperature and pressure is 14.7 [psia] and 520 [°R], respectively. Ideal gas behavior is assumed (i.e., Z = 1).

The total work of compression of the multiple stage compressor is multiplied by the compressor discharge rate and divided by the compressor efficiency to calculate the brake horsepower requirement as:

Production & Extraction 3.3.5

$$\text{BHP}_C = \sum_{N=1}^{3} \frac{W_N Q_d}{\eta_C} \qquad [\text{hp}] \tag{3.25}$$

where Q_d = compressor discharge rate [MMscf/d]; and η_C = compressor efficiency [fraction].

3.3.2.10 Driver fuel consumption

The total brake horsepower requirement (BHP) is used to determine the driver size. A database of drivers of different types and sizes (natural gas engine, diesel engine, electric motor, etc.) is built in the *'Drivers'* supplementary worksheet using technical worksheets of engine and motor manufacturers such as Caterpillar and General Electric [89, 90]. Natural gas fueled drivers, for example, range from 95 hp engine to 20,500 hp turbine. The appropriate driver is retrieved from a database based on the chosen driver type and the required driver size. Finally the fuel consumption of the component (pump, compressor, etc.) is calculated as:

Production & Extraction 3.3.6

$$E_j = \text{BHP}_j \cdot e_D \cdot \frac{24}{10^6} \qquad \left[\frac{\text{MMBtu}}{\text{d}} \right] \tag{3.26}$$

where E_j = component fuel consumption [MMBtu/d]; and e_D = driver fuel consumption [Btu/hp-hr]. The type of fuel consumed (i.e. natural gas, diesel, etc.) is determined by the chosen type of driver.

The driver fuel consumption is required for the calculation of energy consumption of various production components. This includes sucker-rod pumps, electric submersible pumps, water injection pumps, and gas compressors.

3.3.3 Production and extraction defaults

Default values for production and extraction equations are shown in Table 3.5. The data basis for smart defaults for production and extraction modeling are described below.

Table 3.5: Default inputs for production and extraction.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
°API	API gravity	(3.3)	-	-	[-]	[48, p. 47]	
A_P	Pipeline cross sectional area	-	$\pi\left(\frac{D_P}{2}\right)^2$	-	[ft^2]		
BHP_P	Pump brakehorse power	(3.23)	-	-	[hp]	[57, p. 27]	
BHP_C	Compressor brakehorse power	(3.25)	-	-	[hp]		
BHP_j	Component j brakehorse power	-	-	-	[hp]		
C_{sd}	Concentration of dissolved solids	-	5000	-	[mg/L]	[91]	
$C_{p/v}$	Ratio of specific heats	-	1.28	1.16-1.40	[-]	[71, p. 320]	a
D_P	Well diameter	-	2.78	1.04-4.50	[in]	[41, p. 121]	
η_P	Pump efficiency	-	65%	70%	[-]	[57, p. 27]	b
η_C	Compressor efficiency	-	70%	75-85%	[-]	[55, p. 105]	c
E_j	Fuel consumption of component j	(3.26)	-	-	[MMBtu/d]		
e_D	Driver fuel consumption	-	var.	Section 4.4	[Btu/hp-hr]		
f	Friction factor	(3.14)	0.02	$\leq$0.1	[-]		d
γ_o	Oil specific gravity	-	0.84	0.8-1.05	[-]	[83]	e
γ_g	Gas specific gravity	(3.4)	-	-	[-]	[84, p. 10]	
γ_w	Water specific gravity	(3.6)	-	-	[-]	[42, p. I-481]	
γ_l	Liquid mixture specific gravity	(3.19)	-	-	[-]	[84]	
g_c	Gravitational constant	-	32.2	-	[lbm-ft/lbf-s^2]		
h	Well depth	-	7240	-	[ft]	Figure 3.6	
h_{tot}	Total head	(3.11)	-	-	[ft]		
h_{el}	Elevation head	-	h	-	[ft]		
h_f	Frictional head	(3.12)	-	-	[ft]	[71, p. 447]	
λ_o	Volume fraction of oil	(3.20)	-	-	[-]		
λ_w	Volume fraction of water	-	$1-\lambda_o$	-	[-]		

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
MW_g	Gas molecular weight	-	var.	-	[lbm/lbmol]	[47, p. 35]	f
μ_l	Fluid viscosity	-	var.	-	[cP]		
Nre	Reynolds number	(3.13)	-	-	[unitless]	[87]	
N_W	Number of producing wells	-	$\frac{Q_o[\text{bbl/d}]}{183[\text{bbl/well-d}]}$	-	[-]	Section 3.3.3.3	
p_b	Base pressure	-	14.7	-	[psi]	[47, p. 35]	
p_d	Flow discharge pressure	-	var.	-	[psi] or [psia]		
p_s	Compressor suction pressure	-	125	-	[psia]		
$p_{trav,tot}$	Total pressure traverse	(3.18)	-	-	[psi]	[71, p. 455]	g
p_{lift}	Pressure for lifting	(3.21)	-	-	[psi]		
p_{wh}	Wellhead pressure	-	1000	-	[psi]	[47, p. 80]	
p_{res}	Reservoir pressure	-	$0.5\left(\frac{h[\text{ft}]}{2.31[\text{ft/psi}]}\right)$	-	[psi]		
p_{wf}	Bottomhole pressure	-	-	-	[psi]		
PI	Well productivity index	(3.22)	3	-	[bbl liquid/psi-d]		
$Q_{l,W}$	Wellbore flow rate	(3.16)	-	-	[ft^3/s]		
Q_d	Discharge flow rate	-	var.	-	[bbl/d] or [MMscf/d]		
Q_l	Total rate of liquid production	(3.17)	-	-	[ft^3/s]		
Q_o	Total rate of oil production	-	1500	-	[bbl/d]		
r	Relative pipe roughness	-	0.0006	-	[unitless]	[88]	
R_C	Compression ratio	(3.7)	-	-	[-]		
ρ_{gsc}	Gas density at standard conditions	(3.5)	-	-	[lbm/ft^3]	[47, p. 35]	
ρ_{asc}	Air density at standard conditions	-	0.0764	-	[lbm/ft^3]	[84, p. 10]	
T_b	Base temperature	-	520	-	[°R]	[47, p. 35]	
T_d	Compressor discharge temperature	(3.9)	-	-	[°R]	[55, p. 105]	
T_s	Compressor 1 suction temperature	-	656.7	-	[°R]		
T_{s2}	Compressor 2 suction temperature	(3.10)	-	-	[°R]		h
$v_{l,W}$	Pipeline flow velocity	(3.15)	-	-	[ft/s]	[84]	
WOR	Water-to-oil ratio	-	Section **??**	-	[bbl water/bbl oil]		

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
Z	Compressibility factor	-	1.0	-	[-]		

a - The default of the ratio of specific heats for methane (not pure) is 1.28. In the case of nitrogen gas the default is 1.40.
b - A typical centrifugal pump efficiency is 70% [57, p. 23]. OPGEE default is slightly more conservative to account for wear, tear, older equipments, etc.
c - Compression efficiency accounts for losses of energy stemming from thermodynamics and mechanical causes. A typical range for compression efficiency is 75-85% [55, p.05]. OPGEE default is more conservative to account for wear, tear, older equipments, etc.
d - For the calculation of the friction head a Moody friction factor of 0.02 is assumed.
e - See *'Fuel specs'*. Crude oil specific gravity varies between 0.8 and 1.05 in most cases.
f - Calculated based on the molecular weights and molar fractions of gas constituents.
g - Pressure traverse is calculated from the total head using the pressure gradient of fresh water.
h - Assume compressibility factor Z of 1.0 in the calculation of the compression energy.

3.3.3.1 Default field age

Field age data were collected for global oil fields. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [92]. A total of 4837 of these fields had reported discovery dates. No data are available on date of first production, although this commonly occurs less than 5 years after discovery.

The histogram of field discovery dates is shown in Figure 3.4. Because of a lack of field-specific production data in the same dataset, a production-weighted average age figure was not thought to provide an accurate representation of the true production-weighted age distribution, so this was not calculated. The mean date of discovery in the dataset was 1972.1. If a conservative 3 year development timeline is assumed, an average of 35 years has elapsed between 1975 and 2010.

User Inputs & Results 3.2.3

However, many of these fields are likely small fields that do not supply large quantities of oil to the global export markets. It is known that giant oilfields are somewhat older on average than the general field population [93–96]. A database of 116 giant oilfields was collected (defined as all producing over 100 kbbl/d in the year 2000) [94, Appendix A]. In total, these 116 fields produced ≈32,000 kbbl/d, or some 43% of global oil production in 2000.

These giant fields have a count distribution and produciton-weighted average age distribution that are somewhat older than the complete set of global fields. Figure 3.5 shows these distributions. The production-weighted average discovery year of the sample was 1960.2, for an average age of 40 years since discovery at the time of production data collection (weighted by year 2000 production data). Data on giant oilfield production in 2010 are not available. Due to the general global slowdown in the discovery of giant fields since the 1970s, it is likely that the age distribution of giant oilfields has not shifted in step with advancing years. Therefore, the production-weighted average age for large fields is likely now greater than 40 years.

3.3.3.2 Default field depth

Field depth data were collected for a large number of global oil fields [92]. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey*. Of these fields, 4489 fields had depth data presented. For fields where a range of depths was presented, the deeper depth is used.

The distribution of depths by number of fields per depth range is presented in Figure 3.6. Because of sporadic reporting of production data in the same dataset, a production-weighted depth figure was not thought to provide an accurate representation. The mean depth for these 4489 fields is 7238, or ≈ 7240 ft. The standard deviation is 3591 ft. The depth distribution has a longer right (deep) tail than left (shallow) tail, so the mean is somewhat larger than the median (median = 6807 ft).

User Inputs & Results 3.2.4

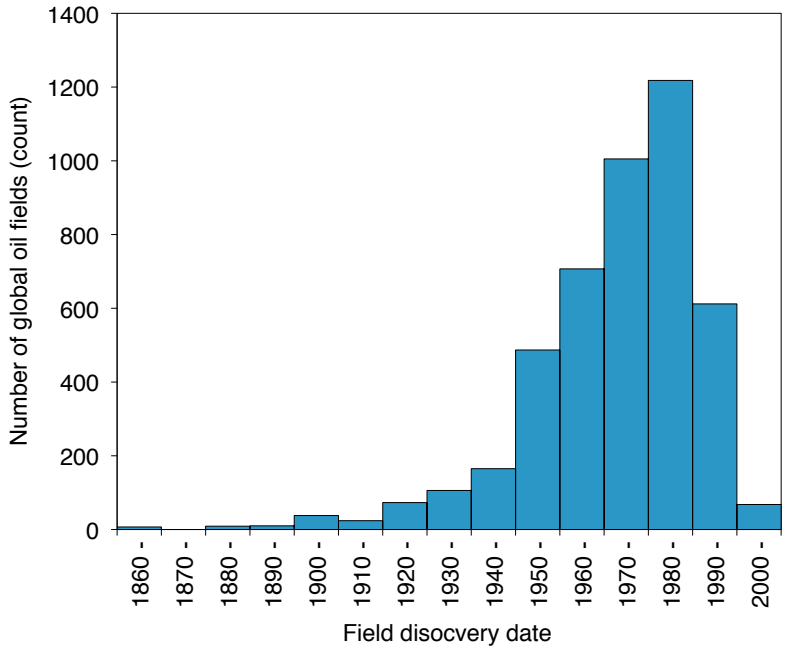

Figure 3.4: Distributions of global oilfield ages. Mean date of discovery (by count not by production-weighted average) is 1978.4.

3.3.3.3 Default production per well

Country-level oil production data and numbers of producing wells were collected for a large number of oil producing countries. Data from a total of 107 oil producing countries were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [97]. Production data and operating well counts for 2008 were collected from 92 of these 107 countries.

The distribution of per-well productivities for all countries is shown in Figure 3.7. A majority of oil producing countries produced less than 500 bbl/well-d. Weighting these well productivities by country-level share of global production, we see a very similar distribution.

Because of the large number of countries producing less than 500 bbl/well-d, we plot the distribution for countries under 500 bbl/well-d (see Figure 3.8). For the 55 countries with per-well productivity less than 500 bbl/well-d, the most common productivity by number of countries was the 0-25 bbl/well-d. However, when weighted by total production, the most common productivity bin is 75-100 bbl/well-d.

In 2008, the world produced 72822 kbbl/d from 883691 wells, for an average per-well productivity of 82 bbl/well. However, the very low productivity of the US oil industry (representing ≈512000 wells) pulls down this average significantly. Non-US producers averaged a per-well productivity of 183 bbl/well-d, which is used as default well productivity in OPGEE.

User Inputs & Results 3.2.6

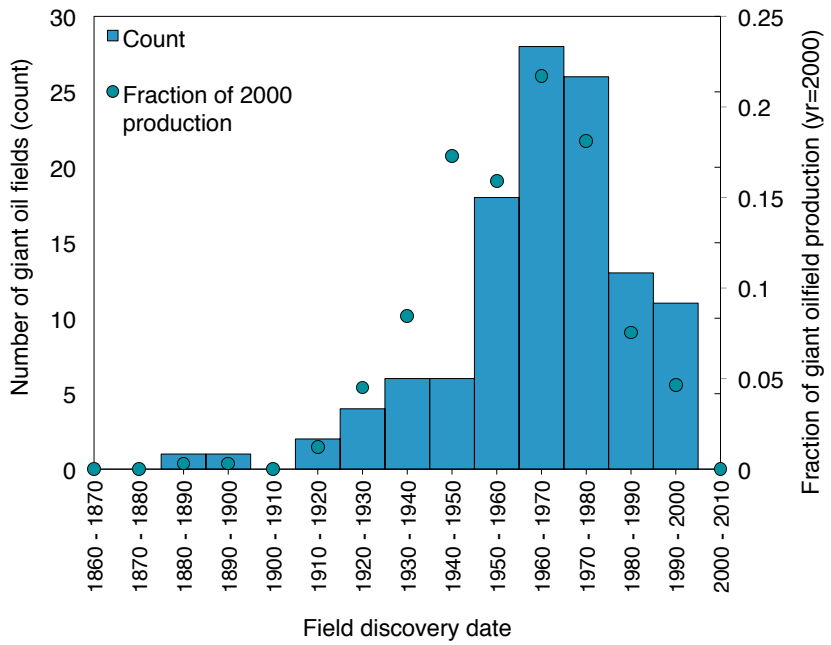

Figure 3.5: Distributions of giant oilfield ages. Mean date of discovery (by production-weighted average) is 1960.2.

3.3.3.4 Default number of injector wells

The default number of injector wells is a smart default based on the number of producing wells. To model this relationship, data from California, Alaska, and a variety of offshore fields was collected [98, 99]. Data from offshore fields is provided in Table 3.7 below. Per-well productivity across these fields ranges from less than 10 bbl/d to over 10,000 bbl/d.

A strong relationship is seen between the productivity of producing wells and the number of injection wells required. Highly productive wells require a significantly larger number of injectors. Figure 3.9 shows the relationship between the per-well productivity of a field and the ratio of injectors to producers.

From these data, a relationship was generated for the mean and median ratio for each logarithmic bin of production well productivity (see Table 3.6). Median values for each bin are used to define the smart default for the number of injector wells.

User Inputs & Results 3.2.7

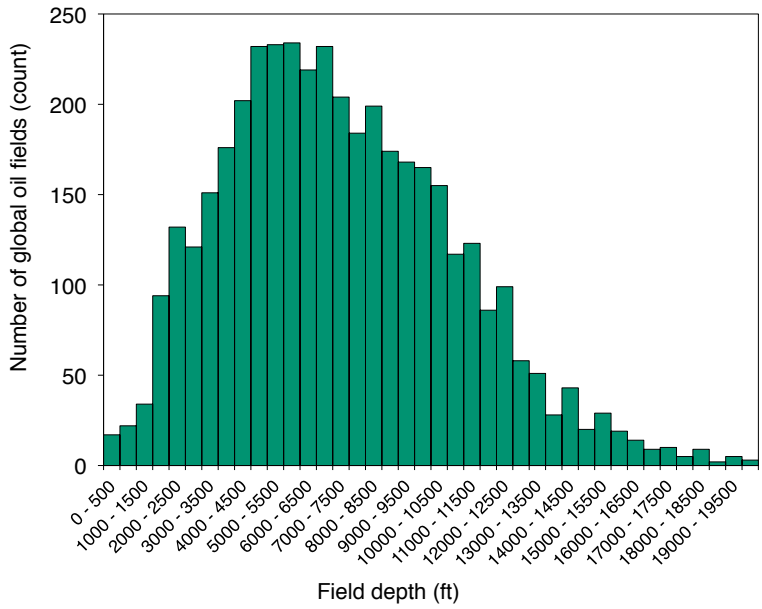

Figure 3.6: Distributions of global oilfield depths in bins of 500 ft depth. N = 4489 fields, mean = 7238 ft, SD = 3591 ft, median = 6807 ft.

Table 3.6: Mean and median injector to producer ratios.

Prod. well productivity	Mean	Median
0-10 bbl/d	0.193	0.143
10 - 100 bbl/d	0.326	0.254
100 - 1000 bbl/d	0.578	0.532
$>$ 1000 bbl/d	0.716	0.831

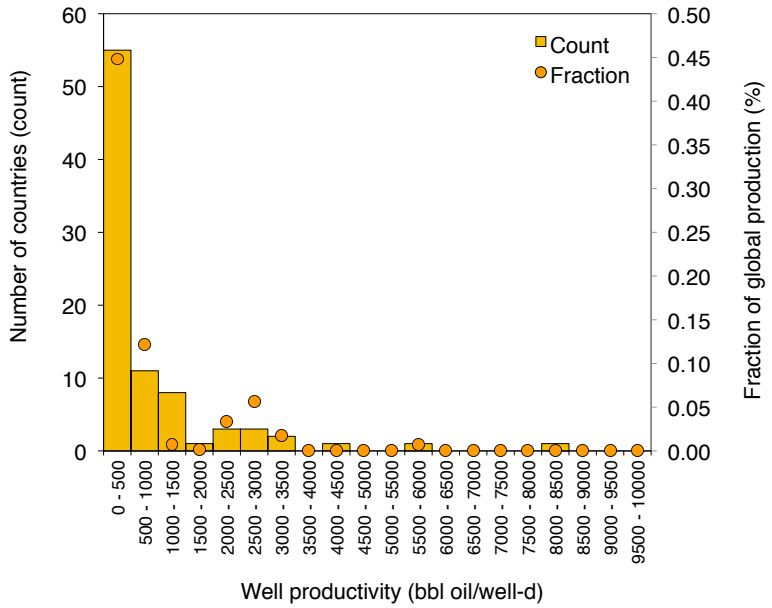

Figure 3.7: Distributions of oilfield per-well productivity (bbl oil/well-d) for bins of 500 bbl/d, counted by numbers of countries (bar) and by fraction of production (dot) $N = 92$ countries.

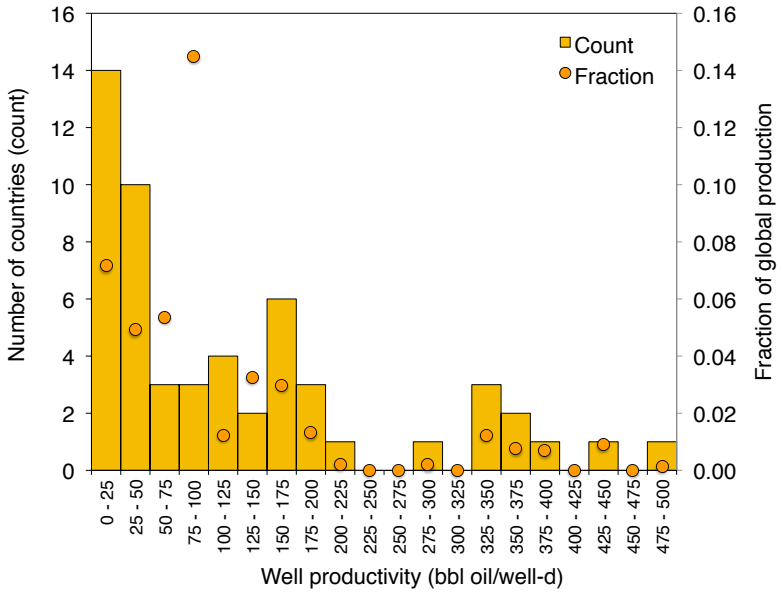

Figure 3.8: Distributions of oilfield per-well productivity (bbl oil/well-d) for all countries with per-well productivities lower than 500 bbl/well-d, counted by numbers of countries (bar) and by fraction of production (dot) $N = 55$ countries.

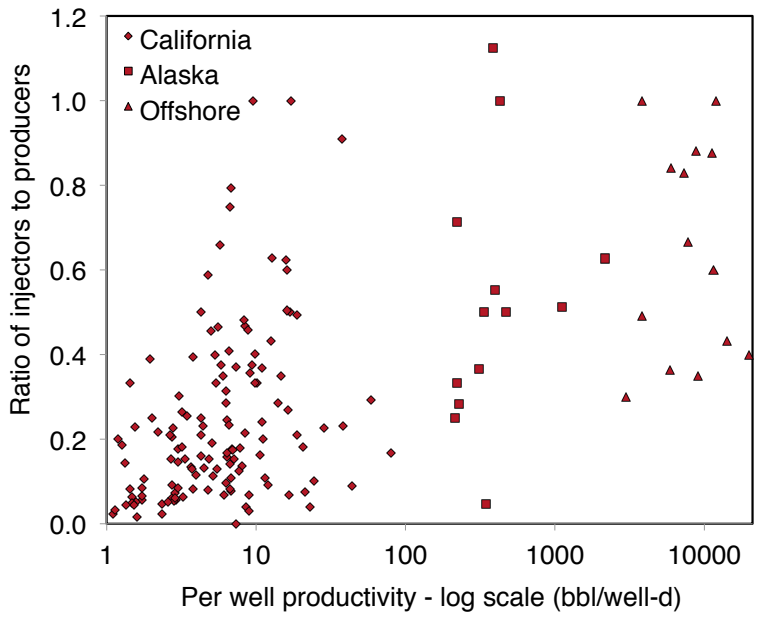

Figure 3.9: Ratio of producers to injectors as a function of per-well productivity. Source: various.

Table 3.7: Data on production, number of production wells, and number of injection wells by offshore field.

Field	Prod. wells	Inj. wells	Prod. (bbl/d)	References
Dalia	37	31	240000	http://www.offshore-technology.com/projects/dalia/
Gimboa	3	4	14000	http://www.statoil.com/en/OurOperations/TradingProducts/CrudeOil/Crudeoilassays/PagPa/Gimboa.aspx http://www.offshore-technology.com/projects/gimboa/
Girassol	23	13	240000	http://www.offshore-technology.com/projects/girassol/
Plutonio	20	20	240000	http://www.offshore-technology.com/projects/greater_plutonio/
Hungo	30	26	130000	http://www.exxonmobil.com/crudeoil/about_crudes_hungo.aspx http://www.fluor.com/projects/Pages/ProjectInfoPage.aspx?prjid=93
Kissanje	25	21	150000	http://www.exxonmobil.com/crudeoil/about_crudes_kissanje.aspx http://www.ogj.com/articles/print/volume-103/issue-38/special-report/kizomba-b-attains-production-capacity-early.html
Mondo	17	17	65000	http://www.exxonmobil.com/crudeoil/about_crudes_mondo.aspx http://www.offshore-technology.com/projects/kizomba/
Pazflor	25	22	220000	http://www.exxonmobil.com/crudeoil/about_crudes_pazflor.aspx http://www.ship-technology.com/projects/pazflor-fpso/
Azeri	58	25	823000	http://crudemarketing.chevron.com/crude/central_asian/azeri.aspx http://www.bp.com/genericarticle.do?categoryId=9029616&contentId=7067613
Albacora Leste	16	14	180000	Albacora Leste Field Development Project, Offshore Technology Conference, 2006 (OTC 17925)
Bijupira	9	6	70000	http://www.offshore-technology.com/projects/bijupira/
Frade	11	4	65000	http://www.offshore-technology.com/projects/fradefieldcamposbasi/
Jubarte	20	7	180000	http://www.epcengineer.com/ http://subseaiq.com/data/Project.aspx?project_id=764&AspxAutoDetectCookieSupport=1
Lula	5	2	100000	http://subseaiq.com/data/Project.aspx?project_id=274
Marlim	102	50	390000	http://www.offshore-technology.com/projects/marlimpetro/
Marlim Sul	41	34	300000	http://uk.reuters.com/article/2011/06/02/petrobras-platform-idUKN0227875420110602 http://subseaiq.com/data/Project.aspx?project_id=371
Polvo	10	3	30000	http://www.offshore-mag.com/articles/print/volume-68/issue-3/production-operations/devon-breaks-new-ground-at-polvo.html
Roncador	40	24	460000	http://subseaiq.com/data/Project.aspx?project_id=348
Sapinhoa	10	10	120000	http://www.offshore-technology.com/projects/guaraoilfield/

3.3.3.5 Default gas composition

The default gas composition for associated gas from oil production is derived from reported gas composition data from 135 California oil fields [100]. Species concentration distributions for major gas species is shown in Figure 3.10. In order to remove outliers, all compositions with methane concentration less than 50% were removed from the dataset (17 data points removed out of 135). The resulting mean compositions were rounded and used in OPGEE for default gas composition.

User Inputs & Results 3.3.2

3.3.3.6 Smart default for GOR

The gas-oil ratio (GOR) varies over the life of the field. The amount of gas able to be evolved from crude oil depends on its API gravity, the gas gravity, and the temperature and pressure of the crude oil [101, p. 297]. As the reservoir pressure drops, increasing amounts of gas evolve from the liquid hydrocarbons (beginning at the bubble point pressure if the oil is initially undersaturated) [101]. This tends to result in increasing producing GOR over time. Also, lighter crude oils tend to have a higher GOR.

Because of this complexity, a static single value for GOR is not desirable. However, all data required to use empirical correlations for GOR is not likely to be available for all crude oils modeled. Therefore we use California producing GORs to generate average GORs for three crude oil bins.

User Inputs & Results 3.4.1

Crude oils are binned by API gravity into heavy (< 20 °API), medium ($\geq 20, < 30$ °API), and light crude (≥ 30 °API). Each California oil field is assigned an average API gravity using the following procedure:

1. API gravity by pool is collected from DOGGR datasets [102–104] and digitized.

2. If a range of API gravities is given for a single pool, the high and low specific gravities are averaged to obtain a single specific gravity value per pool, which is then converted back to API gravity.

3. The above steps give a set of single API values by pool. Each field has between 1 and 17 pools that have data in DOGGR field properties datasets.

4. Each field is assigned an average API gravity using the following method: a) if a single pool API value is given for the field, that is used; b) if multiple pool API gravities are given, and production data are available by pool, the pools are weighted by production level in 2009 DOGGR annual data (again by first converting to specific gravity then converting back to API gravity).

5. The above procedure results in a single API gravity for each field in California.

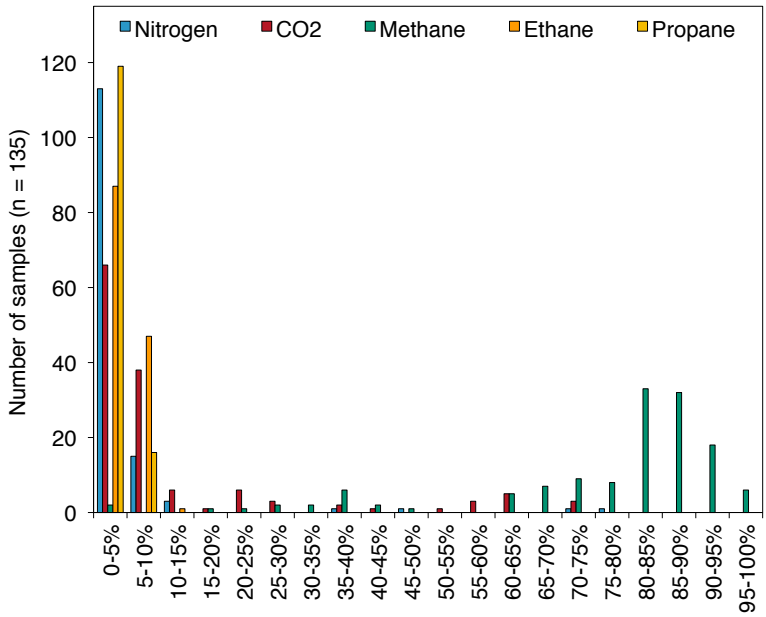

Figure 3.10: Distributions of major gas species across 135 samples from California associated gas producers.

Table 3.8: GOR values by crude oil API gravity bin.

Crude bin	Num. fields [#]	Gravity range [°API]	Avg. gravity [°API]	Mean GOR [scf/bbl]	Median GOR [scf/bbl]
Heavy	45	< 20	15.3	227	8
Medium	69	$\geq 20, \leq 30$	24.3	908	621
Light	65	> 30	35.0	1297	877

The associated gas GOR for 179 California oil fields was compiled for 2009 [105, 106]. These data are binned as above based on their weighted average API gravity value. Outliters with GOR in excess of 10,000 scf/bbl were removed. The distributions, mean, and median values for each crude bin were generated (see Figure 3.11 for plot of distributions and Table 3.8 for listing of mean and median GORs by bin).

The mean GORs are used to assign a smart default for each bin.

3.3.3.7 Default water oil ratio (WOR)

A smart default for the water oil ratio as a function of field age was generated using data from large fields in various world regions. .

User Inputs & Results 3.4.2

Data on oil and water production were extracted from reports issued by California Division of Oil, Gas and Geothermal Resources (DOGGR), Alberta Energy Resources Conservation Board (ERCB), Alaska Oil and Gas Conserva-

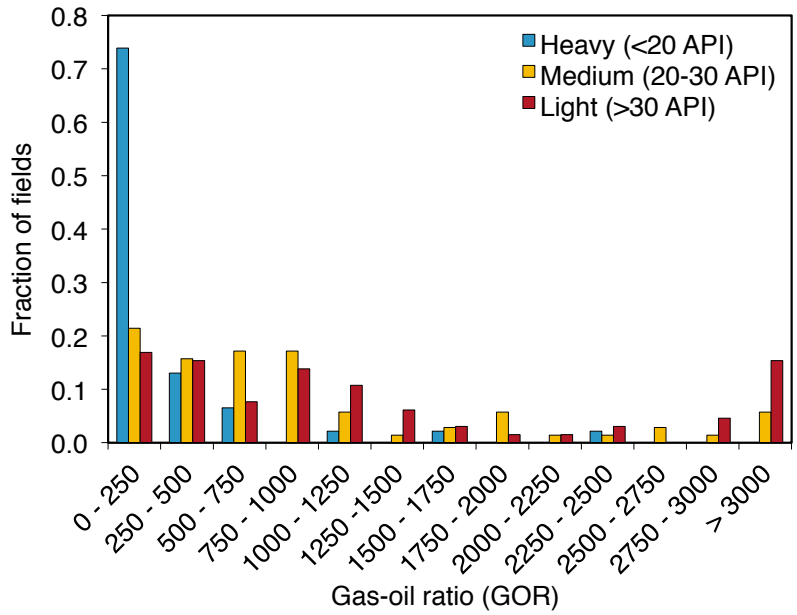

Figure 3.11: Distributions of California GORs, binned by crude density.

tion Commission (AOGCC), United Kingdom Department of Energy and Climate Change (DECC), and the Norwegian Petroleum Directorate (NPD). For the Norwegian fields, water production data were not available prior to the year 2000. For Alberta fields, data were not available prior to 1962. Only data for the first 60 years of production were included. Only California fields contained data beyond 55 years, and therefore we excluded these years to avoid possibly atypical depleted field behavior in California from significantly affecting the least squares fit.

Because the majority of crude oil that is marketed globally originates from larger oil fields, fields that have produced less than 100 million m^3 (630 million bbl) of crude oil were excluded. Also excluded from the analysis were fields that produce heavy crude using steam injection.

Additionally, a small number of fields were excluded because of apparent data anomalies or unusual events that may have affected oil or water production. Both the Redwater field in Alberta and the Ninian field in UK North Sea were excluded for data anomalies. These fields have highly unusual water production data that can only be plausibly attributed to data entry error. Also, the Elk Hills field in California was excluded because it was part of the National Petroleum Reserve for many years and the Piper field in the UK was excluded because oil production was halted for several years. In total, data from 24 giant oil fields (10 onshore and 14 offshore) were included in the analysis. The largest and the only super-giant field to be included is Prudhoe Bay.

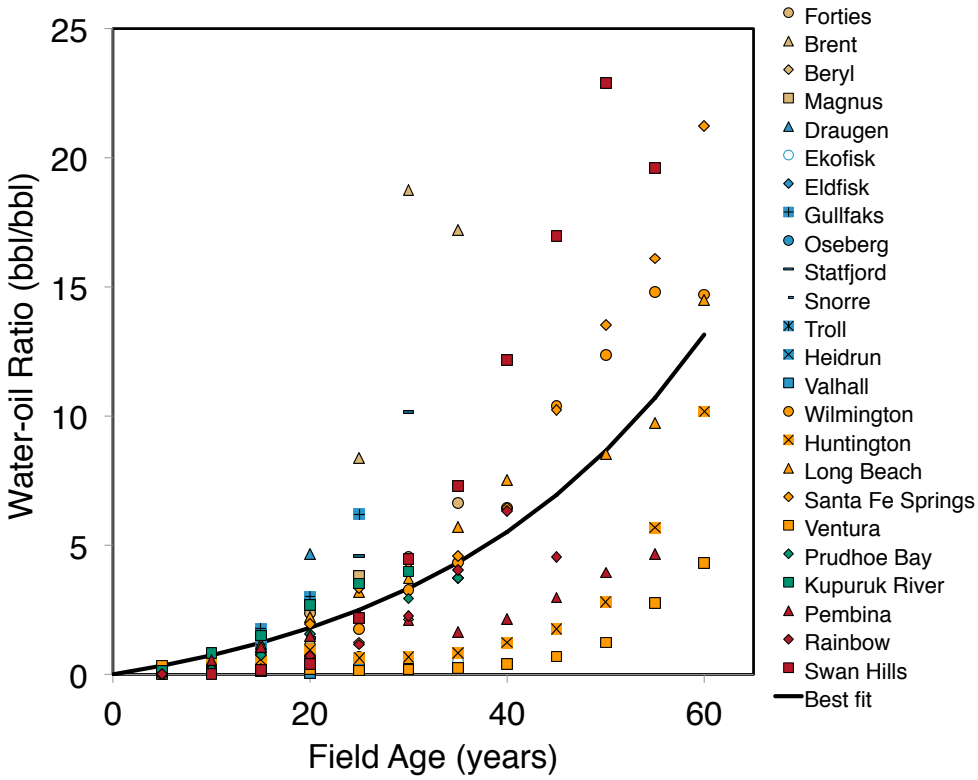

Figure 3.12: Exponential WOR model fit with smart default parameters. The best fit to data gives $a_{WOR} = 0.036$ and $b_{WOR} = 1.706$. Regions are colored as follows: Alberta (red), Alaska (green), California (orange), Norway (blue) and UK (beige).

The default WOR is represented by an exponential function:

$$WOR(t) = a_{WOR} \exp[b_{WOR}(t - t_0)] - a_{WOR} \qquad \left[\frac{\text{bbl water}}{\text{bbl oil}}\right] \tag{3.27}$$

where a_{WOR} = fitting constant for the initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of analysis [y]; and t = year being modeled (independent variable) [y]. Note that the pre-exponential a_{WOR} is subtracted to force WOR to start at 0 when $t = 0$. This model was fit to the collected data using a nonlinear least-squares fit from multiple starting points to ensure robustness.

The results of fitting this model to the smart default fit values, compared to oil fields from a variety of world regions, is show in figure 3.12. The resulting fit gives $a_{WOR} = 0.036$ and $b_{WOR} = 1.706$.

3.3.3.8 Default waterflooding volume

The volume of water injected in a waterflooding project is meant to maintain reservoir pressure. As a default value, OPGEE assumes that the surface vol-

User Inputs & Results 3.4.3

ume is replaced, such that the total oil produced plus the water produced is reinjected, or the injection per bbl = 1 + WOR.

3.4 Surface processing

3.4.1 Introduction to surface processing

Surface processing of crude oil includes all production steps required after lifting the crude oil from the subsurface and before it is transported to the refinery. Activities undertaken in surface processing include oil-water-gas separation, treatment and stabilization of crude oil, and treatment and cleanup of produced gas.

The first step in the processing of crude oil is the separation of individual phases (gas, liquid hydrocarbon, liquid water and solids). This is performed as early as is practical. Field processing schemes can vary considerably depending on the nature of produced fluids (water cut, gas-to-oil ratio and the nature of crude oil, e.g., API gravity), the location and size of the field, availability of gas and electricity, the relative value of gas and crude oil [48, p. 65].

In OPGEE it is not possible to account for the wide variations in surface processing. The goal is to include the most frequently applied processes in the industry, while still retaining some flexibility to model varying operating modes and processing schemes.

A complete list of emissions sources from surface processing, along with their estimated magnitude, is shown in Table C.4. A list of all equation parameters and their default values (if applicable) and data sources is included in Table 3.11.

3.4.2 Calculations for surface processing

3.4.2.1 Crude oil dehydration

The production separator can be a gas-liquid separator or a gas-water-oil separator. The type of production separator determines whether free water is removed at an early stage in the processing scheme. After free water removal, produced oil often contains excessive emulsified water. Treating via crude oil dehydration is required to reduce the water content to a level acceptable for transportation and sale.

Crude oil dehydration can be accomplished by gravitational / chemical means without heat. If this separation is not sufficient, heat can be applied to aid the separation of crude oil and water. The application of heat in the dehydration of crude oil is a significant source of fuel consumption in surface processing.

Gravity separation occurs in large holding vessels called wash tanks, settlers, or gun barrels, and in free-water knockouts (FWKO). FWKOs remove only free water. Emulsion breaking chemicals can be added upstream from the FWKO to improve separation. Better gravitational/chemical separation can be achieved in holding vessels. Holding vessels generate a “washing” action with mild agitation that causes contact between the entrained water drops and the retained water volume, thus coalescing and removing water droplets

from the oil stream [48, p. 118]. The advantage of wash tanks is that they use coalescence and retention time instead of heat (no fuel use) [107] [48, p. 119]. Because no fuel is used in these gravitational separation techniques, no significant GHG emissions occur from gravity separation units.

Depending on the nature of the well stream, the above gravity separation techniques may not be sufficient to produce crude oil with the desired water content. Additional treatment may be provided by a heater/treater. OPGEE allows the user to switch on and off the heater/treater.

Heater/treater placement in the processing scheme affects the total heater treater duty. If the full well stream is the feed stream, then the section of the heater/treater below the firetube is sized to allow for significant retention time to drop out more than half of the free water. Heaters/treaters, however, are not suitable for removing large amounts of free water, and this limitation becomes more acute in older fields as WOR increases [48, p. 120]. Removing free water before flowing the crude oil mixture into a fired heater saves considerable fuel. It takes 350 Btu to heat 1 bbl of water 1 °F but only 150 Btu to raise 1 bbl of oil 1 °F [48, p. 188]. The removal of free water upstream from the heater/treater is therefore desirable from a cost and emissions perspective.

For the calculation of heater/treater duty the best practice is assumed. The bulk of the free water is removed prior to the application of heat. The small amount of free water (1-2%) that was not separated prior to the application of heat is neglected [108, Section 5.4.2].

The first step in the calculation of the heat duty of the heater/treater is the calculation of the volume of heated water. The volume of heated water is equal to the volume of water entrained in oil emulsion:

Surface Processing 2.1.1

$$Q_{w,heat} = Q_{w,ent} \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.28}$$

where $Q_{w,heat}$ = volume of heated water [bbl/d]; $Q_{w,ent}$ = volume of water entrained in oil emulsion, [bbl/d]. The volume of water entrained $Q_{w,ent}$ is calculated from the fraction of water entrained in oil emulsion as:

Surface Processing 2.1.1.1

$$\lambda_{w,ent} = \frac{Q_{w,ent}}{Q_{w,ent} + Q_o}, \quad \text{therefore} \quad Q_{w,ent} = \lambda_{w,ent}\frac{Q_o}{1-\lambda_{w,ent}} \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.29}$$

where $\lambda_{w,ent}$ = fraction of water entrained in oil emulsion [-]; and Q_o = rate of oil production [bbl/d]. The volume of produced water Q_w is calculated from the water-to-oil ratio as:

Surface Processing 2.1 Figure

$$Q_w = \text{WOR} \cdot Q_o \qquad \left[\frac{\text{bbl water}}{\text{d}}\right] \tag{3.30}$$

where WOR = water-to-oil ratio [bbl of water/bbl of oil]. The produced water is the sum of free and entrained waters.

Once the volume of heated water is calculated, the heat duty is calculated using:

Surface Processing 2.1.1.3

$$\Delta H_{CD} = \Delta T_{CD} \left(Q_o C_{p_o} + Q_{w,heat} C_{p_w} \right) (1 + \epsilon_{CD}) \left(\frac{1}{10^6} \right) \qquad \left[\frac{\text{MMBtu}}{\text{d}} \right] \tag{3.31}$$

where ΔH_{CD} = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; C_{p_w} = specific heat of water [Btu/bbl-°F]; ΔT_{CD} = difference between treating and feed temperatures [°F]; and ϵ_{CD} = heat loss [fraction]. Default values are 90 and 165 °F for feed and treating temperatures, respectively; 150 and 350 Btu/bbl-°F for specific heats of oil and water, respectively; and 0.02 for heat loss [48, p. 136].

3.4.2.2 Crude oil stabilization

Dissolved gas in the wellhead crude oil must be removed to meet pipeline, storage, or tanker Reid vapor pressure (RVP) specifications. Removal of the most volatile organic hydrocarbons decreases the RVP dramatically and is called crude oil stabilization. Crude oil can be stabilized by passing it through a series of flash drums or separator vessels at successively lower pressures. Tray tower with reboilers, alternatively or in conjunction with separators, are also used, though less often [48, p. 159].

The use of a reboiled stabilizer column is the most important user assumption in the oil-gas separation scheme. Stabilizer columns are tray columns usually provided with sieve trays for vapor-liquid contacting. Vapor, which is produced in the reboiler, flows up the column, stripping out methane, ethane, propane, and sufficient butane to produce a stabilized crude oil [48, p. 160]. The separation achieved is better than in a simple flash drum. Higher pressures correlate with higher separation efficiency. The default type of stabilizer in OPGEE is a high-pressure stabilizer (100 psi) which requires a higher reboiler temperature compared to a low-pressure stabilizer.

The use of a stabilizer column is an important assumption because a heat source is required to provide the neccessary temperature. OPGEE assumes a direct-fired heater. The use of a stabilizer column and the overall complexity of crude oil processing depends on the nature of the well fluids. For instance, when the gas-to-oil ratio (GOR) is between 25-100 scf/bbl, onshore locations are likely to use one stage of flash separation followed by wash tanks. Offshore, two stages of separation might be attractive [48, p. 172]. The comparisons between a series of flash drums and/or reboiled stabilization are of real economic benefit only for high volume, high GOR streams (>150 scf/bbl) [48, p. 163].

The heat duty of the stabilizer column is calculated as:

Surface Processing 2.1.2.2

$$\Delta H_S = \Delta T_S Q_o C_{p_o} (1 + \epsilon_S) \left(\frac{1}{10^6} \right) \qquad \left[\frac{\text{MMBtu}}{\text{d}} \right] \tag{3.32}$$

where ΔH_S = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; ΔT_S = difference between reboiler and feed temperatures [°F]; and ϵ_S = heat loss [fraction]. All of these parameters are user inputs. The default values are

120 and 344 °F for feed and reboiler temperatures, respectively; 150 Btu/bbl-°F for the specific heat of oil; and 0.02 for heat loss [48, p. 161, 163, tables 9-1, 9-3].

3.4.2.3 Acid gas removal

The second step after the separation of individual phases is the treatment of associated gas. Treatment of associated gas starts with acid gas removal (AGR, also called gas sweetening). There are more than 30 natural gas sweetening processes. OPGEE assumes that the amine process is used. The batch and amine processes are used for over 90% of all onshore wellhead applications with amines being preferred when lower operating costs justifies the higher equipment cost. The chemical cost of batch processes may be prohibitive [47, p. 99].

In the amine process an aqueous *alkanolamine* solution is regenerated and used to remove large amounts of sulfur and CO_2 when needed. The model scheme allows the user to choose between the commonly used amine solutions (MEA, DEA, DGA, etc.). Each amine solution is characterized by a K value which is inversely proportional to both the acid gas removal rate (pick up) and amine concentration [47, p. 115]. When choosing an "other" amine solution, the user must enter a K value. The default contactor operating pressure is the median value of the pressures reported in the calculation of the contact tower diameter [109] [47, p. 117]. A schematic of the amine process is shown in Figure 3.13. The user has the option of turning OFF the AGR unit in the gas processing scheme.

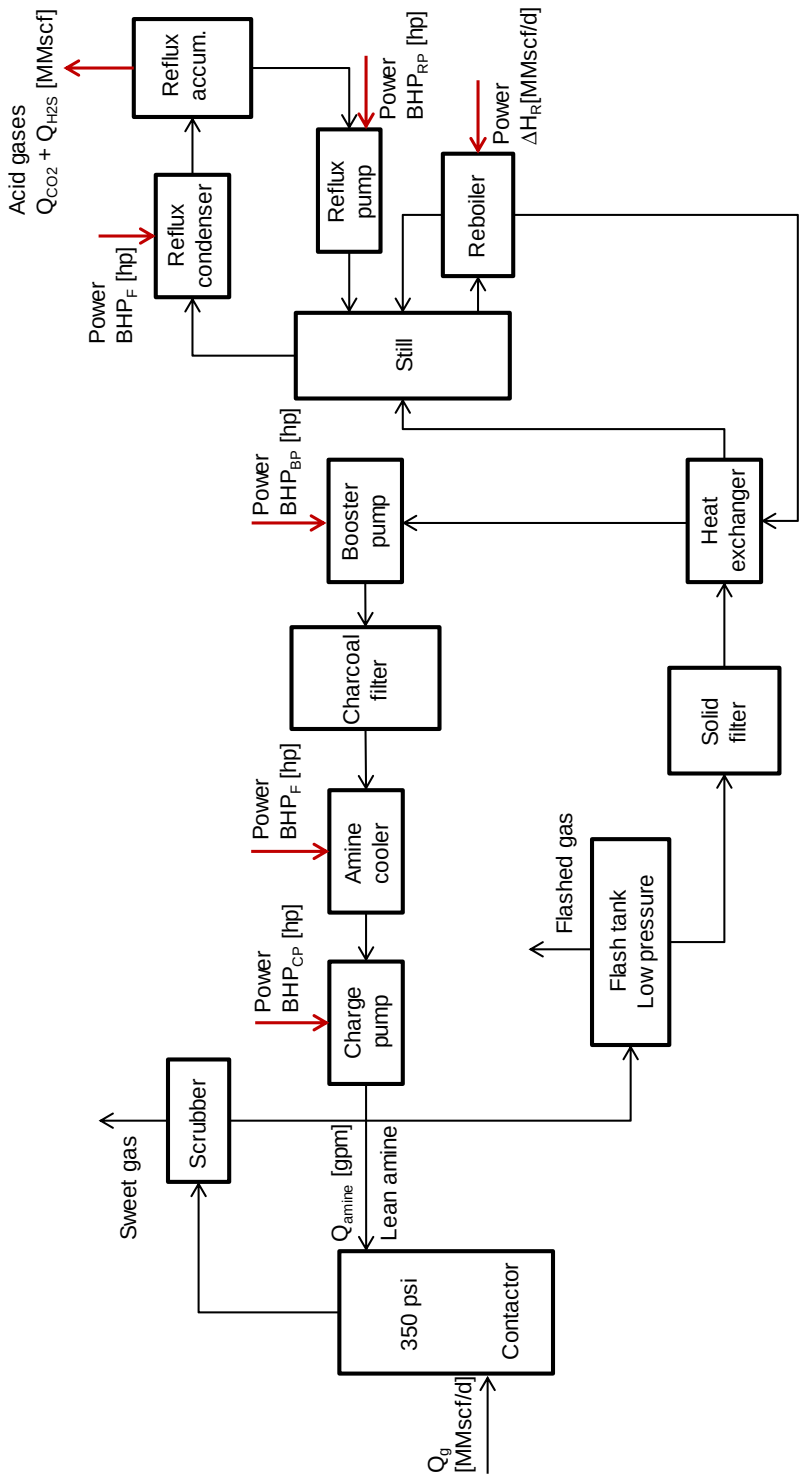

Figure 3.13: Amine simple process flow diagram [47, p. 112].

The inlet gas flow rate of the gas processing stage in the gas balance (see *'Gas Balance'* worksheet) is calculated as:

Surface Processing 2.2.1 Figure

$$Q_g = Q_o \cdot \text{GOR}\left(\frac{1}{10^6}\right) - Q_F \qquad \left[\frac{\text{MMscf}}{\text{d}}\right] \tag{3.33}$$

where Q_g = inlet gas flow rate [MMscf/d]; Q_o = rate of oil production [bbl/d]; Q_F = flaring rate [MMscf/d]; and GOR = gas-to-oil ratio [scf/bbl]. The inlet gas flow rate is used in the calculation of the amine circulation rate in eq. (3.35). Although the accumulation of gases to flare likely occurs at various points throughout the process, OPGEE assumes that the gas flared is removed before gas processing occurs. This allows for OPGEE to account for "early field production" or production in locations without a gas market. For these situations, no surface processing exists and all produced gas is flared.

The amine reboiler in OPGEE is a direct fired heater that uses natural gas. The reboiler duty is: (i) the heat to bring the acid amine solution to the boiling point, (ii) the heat to break the chemical bonds between the amine and acid gases, (iii) the heat to vaporize the reflux, (iv) the heat load for the makeup water, and (v) the heat losses from the reboiler and still [47, p. 117].

The heat duty of the amine reboiler can be estimated from the circulation rate of the amine solution as [47, p. 119—originally Jones and Perry, 1973]:

Surface Processing 2.2.1.4

$$\Delta H_R = \frac{24 \cdot 72000 \cdot Q_{amine}}{10^6} 1.15 \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{3.34}$$

where ΔH_R = heat duty [MMBtu/d]; and Q_{amine} = amine flow rate [gpm]. A gallon of amine solution requires approximately 72000 Btu for regeneration [110]. A safety factor of 15% is added for start up heat losses and other inefficiencies. The flow rate of the amine solution can be estimated using the following equation [47, p. 115]:

Surface Processing 2.2.1.1.1

$$Q_{amine} = 100\, K(Q_{H_2S} + Q_{CO2}) \qquad [\text{gpm}] \tag{3.35}$$

where Q_{amine} = amine flow rate [gpm]; K = amine solution K value [gpm-d/100MMscf]; Q_{H_2S} = H_2S removal [MMscf/d]; and Q_{CO2} = CO_2 venting from AGR unit [MMscf/d]. The venting of CO_2 from the AGR unit is calculated in the *'Gas Balance'* worksheet. The rate of H_2S removal is calculated as:

$$Q_{H_2S} = x_{H_2S} \cdot Q_g \qquad \left[\frac{\text{MMscf}}{\text{d}}\right] \tag{3.36}$$

where x_{H_2S} = molar fraction of H_2S [-]; and Q_g = inlet gas flow rate [MMscf/d]. The calculation of the inlet gas flow rate is shown in eq. (3.33). The molar fraction of H_2S is determined from the composition of associated gas.

In OPGEE all H_2S remaining in the associated gas is removed in the AGR unit. Removed H_2S is calculated in eq. (3.36) by multiplying the inlet gas flow rate with the molar percent of H_2S. Also all the CO_2 removed is vented and that is calculated in the *'Gas Balance'* worksheet.

Other equipment in the amine regeneration system that consume power and energy include the reflux condenser and the amine cooler. There also are reflux, booster, and circulation pumps. The reflux condenser and the amine cooler are air-cooled, forced-draft heat exchangers. In OPGEE both services are combined into one structure with a common fan.

The motor size of the amine cooler fan can be estimated from the amine circulation rate as [47, p. 118]:

Surface Processing 2.2.1.3.1

$$\mathrm{BHP}_F = 0.36 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.37}$$

where BHP_F = fan brake horsepower [hp]; and Q_{amine} = amine circulation rate [gpm].

The heat duty of the reflux condenser is approximately twice the heat duty of the amine cooler [47, p. 117]. Therefore the motor size of the 'common' fan is estimated by multiplying the brake horsepower of the amine cooler by 3.

Similarly motor sizes of pumps can also be estimated from the amine circulation rate as [47, p. 118]:

Surface Processing 2.2.1.2

$$\mathrm{BHP}_{RP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.38}$$

$$\mathrm{BHP}_{BP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.39}$$

$$\mathrm{BHP}_{CP} = 0.00065 \cdot Q_{amine} \cdot p_d \qquad \text{[hp]} \tag{3.40}$$

where BHP_{RP} = reflux pump brake horsepower [hp]; BHP_{BP} = booster pump brake horsepower [hp]; BHP_{CP} = circulation pump brake horsepower [hp]; and p_d = pump discharge pressure [psi]. The circulation pump discharge pressure = 50 psi over contactor operating pressure [47, p. 121]. The default contactor operating pressure as mentioned earlier is 350 psi.

3.4.2.4 Gas dehydration

Fluids at the wellhead almost invariably contain water. Except for a few shallow wells, natural gas is produced saturated with water. There are many reasons for the dehydration of natural gas, including avoiding: (i) solid hydrates formation which can plug valves, fittings or even pipelines; (ii) corrosivity in case the acid gases are still present; (iii) condensation of water which creates a slug flow and increases pressure losses in the pipeline due to slippage; and (iv) decreases in heating value [47, p. 139]. There are several methods for the dehydration of natural gas including liquid (glycols) and solid (e.g., alumina) desiccants. The method assumed in OPGEE as default is triethylene glycol (TEG) desiccant. The user has the option of turning off the gas dehydrator unit based on the characteristics of the modeled field. For more than 40 years sweet and sour gases have been dehydrated using TEG which has general acceptance as the most cost effective choice [47, p. 140].

The wet or "rich" glycol that leaves the absorber is preheated in the glycol-glycol heat exchanger before it enters the stripping column and flows down the

packed bed section into the reboiler. The steam generated in the reboiler strips water from the liquid glycol as it rises up the packed bed. The water vapor and desorbed gas are vented from the top of the stripper [47, p. 140]. The venting from glycol dehydrator is discussed in the Venting & Fugitives section of this document (see Section 4.7). A schematic of the glycol dehydrator is shown in Figure 3.14.

The first step in the estimation of the reboiler duty is the calculation of the rate of water removed using the assumed weight of water vapor in the inlet and exit gases as:

Surface Processing 2.2.2.1.3

$$\Delta M_{w,rem} = M_{w,in} - M_{w,out} \qquad \left[\frac{\text{[lb H}_2\text{O}}{\text{MMscf}}\right] \tag{3.41}$$

where $\Delta M_{w,rem}$ = water removed [lb H_2O/MMscf]; $M_{w,in}$ = water in inlet gas [lb H_2O/MMscf]; $M_{w,out}$ = water in outlet gas [lb H_2O/MMscf]. The weights of water vapor in the inlet and exist gases are user inputs. The default values are 52 and 7 lb H_2O/MMscf, respectively [47, p. 160]. The weight of water removed is converted to rate of water removal ($\Delta Q_{w,rem}$) in lb H_2O/d by multiplying with the gas flow rate, MMscf/d.

The regenerator duty is estimated using the rule of thumb [47, p. 158]:

Surface Processing 2.2.2.2.1

$$\Delta H_{GD} = 900 + 966\, q_{TEG} \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{lb H}_2\text{O}}\right] \tag{3.42}$$

where ΔH_{GD} = reboiler heat duty [MMBtu/lb H_2O] removed; and q_{TEG} = TEG circulation rate [gal TEG/lb H_2O] removed. The heat duty is converted to MMBtu/d by multiplying with the rate of water removed, lb H_2O/d, as calculated in eq. (3.41).

The main parameter in eq. (3.42) is the TEG circulation rate. The water picked up by glycol increases with increasing inlet-glycol concentration and higher circulation rates. The concentration of TEG used typically ranges from 98.5 to 99.9 wt% [47, p. 155]. The default concentration assumed is 99 wt%. In the past a conservative TEG circulation rate of 3 gal TEG/lb H_2O removed was common. However, energy conservation practices have lowered the circulation to 2 gal TEG/lb H_2O removed and this is used as default in OPGEE [47, p. 147].

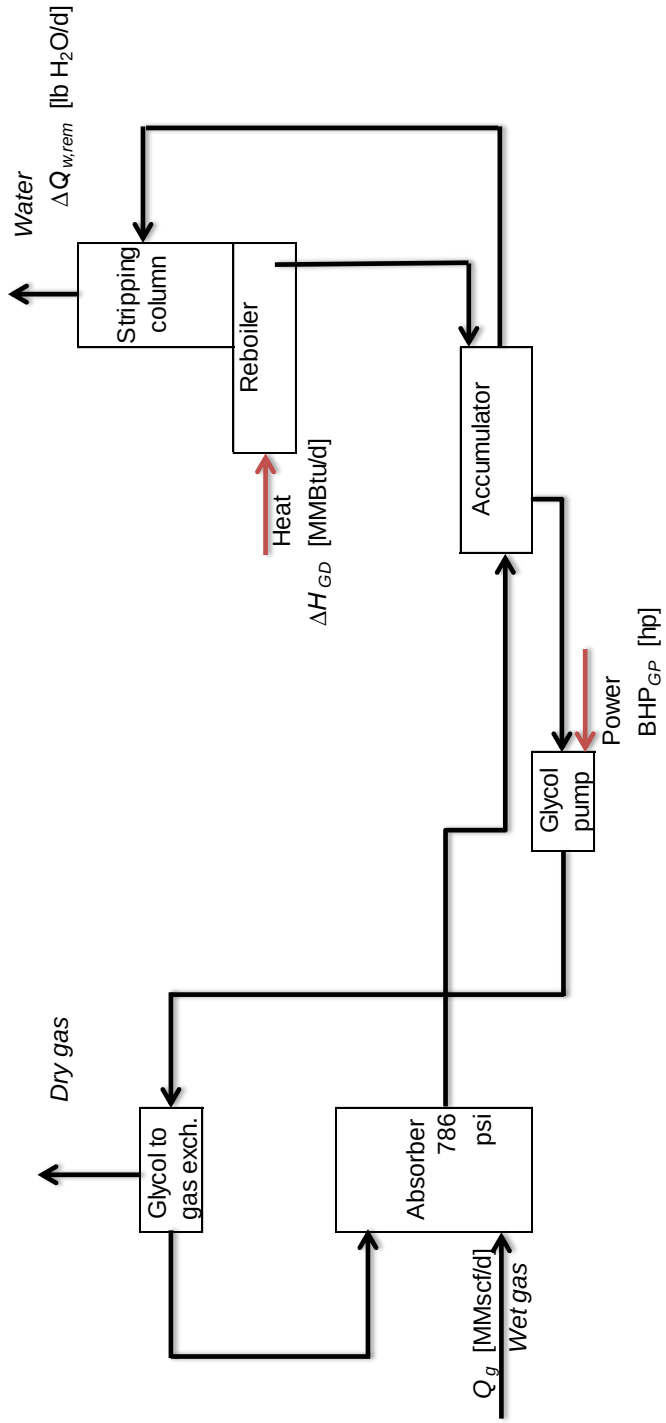

Figure 3.14: Glycol dehydrator simple process flow diagram [47, p. 141].

The glycol pump in the gas dehydration process is assumed to be electric by default. The horsepower is calculated using the conventional brake horsepower equation:

Surface Processing 2.2.2.3

$$\mathrm{BHP}_{GP} = \frac{Q_{TEG} \cdot \Delta p}{1714 \eta_{GP}} \qquad \text{[hp]} \tag{3.43}$$

where BHP_{GP} = glycol pump brake horsepower [hp]; Q_{TEG} = TEG circulation rate [gpm]; Δp = pumping pressure [psi]; and η_{GP} = glycol pump efficiency [-]. The pumping pressure is the difference between pump discharge and suction pressures. The default pump suction pressure is 0 [psi]. The glycol pump discharge pressure is equal to contactor operating pressure. The default contactor operating pressure is 786 psi [47, p. 160]. The TEG circulation rate in gpm is calculated as:

Surface Processing 2.2.2.1.5

$$Q_{TEG} = q_{TEG} \Delta Q_{w,rem} \left(\frac{1}{24 \cdot 60} \right) \qquad \text{[gpm]} \tag{3.44}$$

where q_{TEG} = TEG circulation rate [gal TEG/lb H_2O removed]; and $\Delta Q_{w,rem}$ = rate of water removal [lb H_2O/d]. The calculation of the rate of water removal is shown in eq. (3.41).

3.4.2.5 Gas demethanizer

Low temperature distillation is the most important route for the separation and purification of gas mixtures, especially when high throughputs are required. A demethanizer system is an industrially important example of such a process [111]. The main sources of GHG emissions from the demethanizer unit are the refrigeration system and compressor shaft power and the heat duty of the fractionation column reboiler, if supplemental heat is required. These are calculated using energy factors which are generated from a default configuration [111].

In the default OPGEE demethanizer configuration, the compressor system is assumed to operate upstream of the demethanizer, to produce feed at 60 bar, as in Nawaz paper [111]. The refrigeration duty, on the other hand, is assumed proportional to the amount of gas condensed. Because of sophisticated heat recovery applied in these systems, the cold gas that remains will be warmed back up in exchange with incoming gas. The energy factors of the compressor and refrigeration system are 0.58 [bhp-hr/kmol_{FEED}] and 3.6 [bhp-hr/kmol_{COND}], respectively . As seen in the demethanizer literature, we assume that the reboiler heat duty is provided by heat exchangers from the incoming feed stream. Under this configuration the demethanizer is assumed to condense 90.2% of ethane and 100% of propane and butane [111], which is then assumed to be exported as LPG . These fractions can be changed on the *'Surface Processing'* worksheet. The gas feed measure is in gram moles as reported in the demethanizer unit synthesis report. The gas feed moles is calculated from

Surface Processing 1.2.4.2

Surface Processes 1.2.4.4

Surface Processing 1.2.4

Table 3.9: Typical concentration of process water pollutants.

Pollutants	Concentration (mg/l)
Oil and grease	200
Boron	5
Total dissolved solids (TDS)	5000
Sodium	2100

the *'Gas Balance'* worksheet using the gas composition of the demethanizer feed. The refrigeration brake horse power is calculated as:

$$\mathrm{BHP}_{RS} = \frac{1}{24} \cdot e_{RS} \cdot Q_{g_{in}} \qquad \text{[hp]} \tag{3.45}$$

where BHP_{RS} = refrigeration system shaft brakehorse power [hp]; e_{RS} = energy factor [bhp-hr/kmol$_{COND}$]; and $Q_{g_{in}}$ = demethanizer gas condensed [kmol/d]. The compressor work is calculated similarly. The molar amount of the gas feed and gas condensed is calculated in the *'Surface Processing'* worksheet .

Surface Processing 2.2.3.1

The energy consumption of the compression and refrigeration system is calculated using the fuel consumption of an appropriate NG turbine as determined by the power demand. GHG emissions are calculated using emissions factors of NG turbine from the *'Emissions Factors'* worksheet.

OPGEE allows flexibility in the gas processing scheme. Therefore the demethanizer unit can be turned off in fields with dry associated gas or where NGL recovery is not economic.

3.4.2.6 Water treatment

Oil production generates a significant amount of produced water, which can be contaminated with hydrocarbons, salts, and other undesirable constituents. The fraction of water produced is determined by the WOR. After cleaning, produced water is reinjected, discharged to the local environment, or injected into aquifers. Produced water can contain a variety of pollutants at varying concentrations. The pollutant nature and concentration are largely source dependent including location, geology and age of the oil field [91]. A typical concentration of pollutants found in oil extraction process waters is shown in Table 3.9 [91, p. 59].

Process water from oil production can be treated in a variety of different ways. The technologies in OPGEE are grouped into 4 different treatment stages according to the categorization of water treatment technologies as shown in Table 3.10 [112]. This categorization and the energy consumption of each technology in kWh per m^3 of water *input* (converted to kWh per bbl of water) was adopted from Vlasopoulos et al. [91].

The user can set up a water treatment system or treatment train composed of 1-4 stages of treatment with one option from each treatment stage as shown in Table 3.10. Stage 1 to 3 technologies are used to reduce the oil and grease to

Table 3.10: Categorization of water treatment technologies.

Name	Signifier
Stage 1	
Dissolved air flotation	DAF
Hydrocyclones	HYDRO
Stage 2	
Rotating biological contactors	RBC
Absorbents	ABS
Activated sludge	AS
Trickling filters	TF
Air stripping	AIR
Aerated lagoons	AL
Wetlands	CWL
Microfiltration	MF
Stage 3	
Dual media filtration	DMF
Granular activated carbon	GAC
Slow sand filtration	SSF
Ozone	OZO
Organoclay	ORG
Ultrafiltration	UF
Nanofiltration	NF
Stage 4	
Reverse osmosis	RO
Electrodialysis reversal	EDR

levels that can be either discharged or reused. The fourth stage of treatment is used to reduce the sodium, TDS, and boron levels to produce high quality water required by some end uses [91, p. 60]. The technology combinations are selected according to the target water qualities that need to be achieved.

The model scheme has two treatment trains: (i) one for the treatment of process water generated from oil production and (ii) another for the treatment of imported water, e.g., sea water, if applicable.

The user can set up a treatment train by switching on/off the treatment technologies listed under each treatment stage. One option is allowed for each treatment stage. Based on the user selections, OPGEE retrieves the corresponding electricity consumption and calculates the total electricity consumption:

Surface Processing 2.3.1

$$E_{tot} = e_{s1}Q_{w1} + e_{s2}Q_{w2} + e_{s3}Q_{w3} + e_{s4}Q_{w4} \qquad \left[\frac{\text{kWh}}{\text{d}}\right] \tag{3.46}$$

where E_{tot} = total electricity consumption [kWh/d]; $e_{s,N}$ = electricity consumption of stage N [kWh/ bbl of water input]; and $Q_{w,N}$ = water feed into stage N [bbl of water/d].

For the produced water treatment train the water feed of stage 1 is equal to the water flow in the well stream as calculated in eq. (3.30). The default volume losses are assumed 0% for all treatment technologies except for wetlands which is assumed 26% [91]. The water feed of stages 2-4 is calculated as:

Surface Processing 2.3.1 Figure

$$Q_{w,N} = Q_{w,(N-1)}[1 - \epsilon_{V,(N-1)}] \qquad \left[\frac{\text{bbl of water}}{\text{d}}\right] \tag{3.47}$$

where $\epsilon_{V,(N-1)}$ = volume loss in stage $N-1$ [fraction].

For the imported water treatment train, if applicable, the same calculations apply but the water feed is calculated backwards starting from stage 4 where the output is equal to the amount of water supplied to the process in excess of the output from the produced water train. The volume losses are set to be direct user inputs in the mass balance to avoid circular references.

3.4.3 Defaults for surface processing

Defaults for surface operations are shown in Table 3.11.

Table 3.11: Default inputs for surface processing.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
BHP_F	Fan brakehorse power	(3.37)	-	-	[hp]	[47, p. 118]	
BHP_{RP}	Reflux pump brakehorse power	(3.38)	-	-	[hp]	[47, p. 118]	
BHP_{BP}	Booster pump brakehorse power	(3.39)	-	-	[hp]	[47, p. 118]	
BHP_{CP}	Circulation pump brakehorse power	(3.40)	-	-	[hp]	[47, p. 118]	
BHP_{GP}	Glycol pump brakehorse power	(3.43)	-	-	[hp]	[71, p. 455]	
BHP_{RS}	Refrigeration brakehorse power	(3.45)	-	-	[hp]	[111]	
C_{p_o}	Specific heat of oil	-	150	-	[Btu/bbl-°F]	[48, p. 136]	
C_{p_w}	Specific heat of water	-	350	-	[Btu/bbl-°F]	[48, p. 136]	
E_{tot}	Total electricity consumption	(3.46)	-	-	[Kwh/d]		
$e_{s1} \dots e_{s4}$	Electricity consumption by stage	-	-	-	[Kwh/d]		
ϵ_j	Fraction of heat loss in unit j	-	0.02	-	[-]	[48, p. 136]	
$\epsilon_{V,(N-1)}$	Fraction of volume loss in stage $N-1$	-	var.	-	[-]	[91]	a
η_P	Pump efficiency	-	0.65	-	[-]		
$\lambda_{w,rem}$	Fraction of water removed below fire tube	-	0.4	-	[-]	[48, p.136]	
GOR	Gas-to-oil ratio	-	Section 3.3.3.6	-	[scf/bbl]		
ΔH_R	Amine process reboiler heat duty	(3.34)	-	-	[MMBtu/d]	[47, p. 119]	
ΔH_{GD}	Glycol dehydrator reboiler heat duty	(3.42)	-	-	[MMBtu/d]	[47, p. 158]	
ΔH_{FR}	Fractionation reboiler heat duty	(**??**)	-	-	[MMBtu/d]	[111]	
K	Amine solution K value	-	2.05	0.95-2.05	[gpm-d/100MMscf]	[47, p. 115]	b
$\lambda_{w,ent}$	Fraction of water entrained in oil	-	0.14	-	[-]	[48, p. 136]	
q_{TEG}	TEG circulation rate	-	2	-	[gal TEG/lb H_2O]	[47, p. 147]	
p_d	Pump discharge pressure	-	786	-	[psi]	[47, p. 160]	
$\Delta Q_{w,rem}$	Rate of water removal	-	$Q_g\ \Delta M_{w,rem}$	-	[lb H_2O/d]		
Q_{amine}	Amine flow rate	(3.35)	-	-	[gpm]	[47, p. 115]	

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
Q_{CO_2}	Volume of CO_2 removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	
$Q_{w,ent}$	Volume of entrained water	(3.29)	-	-	[bbl/d]	[48, p. 136]	
Q_F	Flaring volume	-	Section 4.8.1	-	[MMscf/d]		
Q_g	Inlet gas flow rate	(3.33)	-	-	[MMscf/d]	*'Gas Balance'*	
Q_{H_2S}	Volume of H_2S removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	
$Q_{w,heat}$	Volume of heated water	(3.28)	-	-	[bbl/d]	[48, p. 136]	
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{TEG}	TEG circulation rate in gpm	(3.44)	-	-	[gpm]		
Q_w	Volume of produced water	(3.30)	-	-	[bbl/d]		
$Q_{w1} \ldots Q_{w4}$	Water feed by stage	(3.47)	-	-	[bbl water/d]		
ΔT_{CD}	Crude dehyd. temp. difference	-	75	-	[°F]	[48, p. 136]	
ΔT_S	Crude stabilizer temp. difference	-	224	-	[°F]	[48, p. 161, 163]	
$\Delta M_{w,rem}$	Weight of water removed	(3.41)	-	-	[lb H_2O/MMscf]		
$M_{w,in}$	Weight of water in inlet gas	-	52	-	[lb H_2O/MMscf]	[47, p. 160]	
$M_{w,out}$	Weight of water in outlet gas	-	7	-	[lb H_2O/MMscf]	[47, p. 160]	
WOR	Water-to-oil ratio	(3.27)	-	-	[bbl water/bbl oil]]		

a - This is a user input. No defaults are available for most of the treatment technologies. The default for wetlands (CWL) where volume losses are significant is 26% [91].
b - The default is monoethanolamine (MEA).

3.5 Maintenance operations

3.5.1 Introduction to maintenance operations

Emissions from maintenance include venting and fugitives associated with compressor blowdowns, well workovers and cleanups, separator cleaning and repair, and gathering pipeline maintenance and pigging. Other maintenance emissions are believed to be below the significance cut-off and are not included.

3.5.2 Calculations for maintenance operations

Emissions from maintenance operations are classified in Table C.5. Emissions from maintenance operations are either very small (e.g., embodied energy consumed in maintenance parts) or are tracked in the *'Venting & Fugitives'* worksheet (see Section 4.7). For this reason, OPGEE does not perform specific maintenance emissions calculations in the separate *'Maintenance'* worksheet.

3.5.3 Defaults for maintenance operations

Defaults used in the calculation of emissions from maintenance operations are discussed in Section 4.7.

3.6 Waste treatment and disposal

3.6.1 Introduction to waste treatment and disposal

Emissions from waste disposal occur during routine oilfield maintenance operations (e.g., disposal of residual hazardous waste products) due to clean up operations, or due to one-time events such as decommissioning of oilfield equipment. Emissions occur offsite due to the energy demands of waste disposal and the transport requirements for moving waste to waste treatment or disposal sites. A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.6.

3.6.2 Calculations for waste treatment and disposal

Because waste treatment emissions only occur sporadically, they are likely to be small when amortized over the producing life of an oil field. For this reason, emissions from waste treatment are considered below the significance cutoff in OPGEE v1.1.

Possible exceptions could be the treatment and disposal of fracturing fluids and fracturing flow-back water, due to the large volumes produced. Future versions of the model may include these factors.

3.6.3 Defaults for waste treatment

Waste treatment emissions default to 0 gCO_2/MJ. Any waste treatment emissions are assumed to be captured in the small sources emissions default parameter.

User Inputs & Results 3.9

3.7 Crude oil transport

3.7.1 Introduction to crude oil transport

Crude oil transport includes all activities associated with moving crude oil from a production facility to a refinery. In the case of land transport, this generally involves transport via pipeline to the refinery. Pipelines are powered by natural gas, oil, or electric-powered drivers. In some instances, rail transport is used for overland transport. In the case of inter-continental trade, crude oil is transported to a loading dock, loaded onto a tanker or barge, transported via ship over water, unloaded at the destination, and finally transported to a refinery.

Transport emissions occur due to energy consumption by transport equipment and due to fugitive emissions from loading and unloading operations. In OPGEE, transport emissions are modeled using methods and data from CA-GREET [74]. Transport emissions calculations allow for variations in transport modes, distance travelled, and fuel mix in each mode.

3.7.2 Calculations for crude oil transport

OPGEE crude oil transport calculations use sets of transport modes, transport propulsion technologies in each mode (most commonly one technology per mode), and transport fuels. Emissions are tracked per species of GHG. Transport modes include tanker (T), barge (B), pipeline (P), and rail (R). Pipelines include two propulsion technologies: turbines (GT) and reciprocating engines (RE). Fuels used in transport include diesel fuel (di), residual oil (ro), natural gas (ng), and electricity (el).

The effectiveness crude oil transport [Btu/ton-mi] is calculated for a variety of modes using a similar general form. Each mode has an effectiveness U. For example, tanker transport effectiveness is calculated as:

Crude Transport Table 2.7

$$U_T = \frac{\eta_T l_T P_T}{v_T C_T} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = \frac{\left[\frac{\text{Btu}}{\text{hp-hr}}\right][-][\text{hp}]}{\left[\frac{\text{mi}}{\text{hr}}\right][\text{ton}]}, \tag{3.48}$$

where U_T = specific energy intensity of crude oil transport via tanker [Btu/ton-mi]; η_T = efficiency of tanker transport [Btu/hp-hr]; l_T = load factor of tanker (different on outbound and return trip) [-]; P_T = tanker power requirements [hp]; v_T = tanker velocity [mi/hr]; and C_T is tanker capacity [ton/tanker]. Barge transport is calculated in an analogous fashion.

For the case of pipeline and rail transport, the calculation is simpler. For pipeline transport the effectiveness is calculated as follows:

Crude Transport Table 2.7

$$U_P = \sum_{j \in GT,RE} \lambda_{Pj} U_{Pj} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = [-]\left[\frac{\text{Btu}}{\text{ton-mi}}\right] \tag{3.49}$$

where λ_{Pj} = fraction of each pipeline pumping technology j [-]; and U_{Pj} = effectiveness of pipeline transport for technology j [Btu/ton-mi]. For rail transport, only one technology exists, so no summation is required.

Back haul trips are calculated using GREET factors for the energy intensity of return trips [14]

The energy-specific transport energy intensity is calculated from the transport effectiveness using the energy density of crude oil. For example, in the case of tanker transport:

Crude Transport Table 2.7

$$e_T = U_T \frac{1}{LHV_o} \rho_w \gamma_o \frac{1}{2000} \tag{3.50}$$

$$\left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{Btu}}{\text{ton-mi}}\right] \left[\frac{\text{bbl}}{\text{MMBtu}}\right] \left[\frac{\text{lb}}{\text{bbl water}}\right] \left[\frac{\text{lb/bbl oil}}{\text{lb/bbl water}}\right] \left[\frac{\text{lb}}{\text{ton}}\right] \tag{3.51}$$

where UE_T = crude oil transport intensity per unit of energy transported [Btu/MMBtu-mi], LHV_o = crude lower heating value [MMBtu/bbl]; ρ_w = density of water [lb/bbl]; γ_o = crude specific gravity [-]; and 1/2000 = conversion factor between lb and ton.

Calculating emissions of GHG species associated with the consumption of a given energy type in a given device is performed via multiplication with the appropriate emissions factor. For example, in the case of tanker emissions:

Crude Transport Table 2.7

$$\begin{aligned} EM_{Ti} &= e_T \sum_k \lambda_{Tk} EF_{Tki}, \qquad (k \in di, ro, ng) \\ \left[\frac{\text{g}}{\text{MMBtu-mi}}\right] &= \left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] [-] \left[\frac{\text{g}}{\text{Btu}}\right] \end{aligned} \tag{3.52}$$

where EM_{Ti} = emissions of species i from tankers [g/MMBtu-mi]; λ_{Tk} = fraction of fuel k used in tankers [-]; and EF_{Tki} = emissions factor for fuel k, species i consumed in tankers [g/Btu]. Other modes are calculated similarly.

The total CO_2 equivalent emissions are then computed by weighting by gas global warming potential (GWP). Again, for the case of tanker transport:

Crude Transport Table 2.7

$$EM_T = \sum_i EM_{Ti} GWP_i, \qquad \left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{g}}{\text{MMBtu-mi}}\right] \left[\frac{\text{g CO}_2\text{ eq.}}{\text{g}}\right] \tag{3.53}$$

where GWP_i = GWP of species i.

The total energy consumption from transport is computed using the distances and fractions of transport, along with the mode-specific energy intensity of transport:

Crude Transport 3.1

$$\begin{aligned} E_{TR} &= \sum_j \lambda_j D_j UE_j \qquad (j \in T, B, P, R) \\ \left[\frac{\text{Btu}}{\text{MMBtu}}\right] &= [\text{mi}] \left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] [-] \end{aligned} \tag{3.54}$$

where D_j = distance of crude oil transport in mode j [mi]; UE_j = energy-specific transport effectiveness for mode j [Btu/MMBtu-mi]; and λ_j = fraction of crude oil transported in mode j. The sum of fractional transport λ can be greater than 1, because some crude may be transported via both pipeline and tanker, for example.

The total emissions are calculated identically:

Crude Transport 3.2

$$EM_{TR} = \sum_j \lambda_j D_j EM_j \qquad (j \in T, B, P, R)$$
$$\left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu}}\right] = [\text{mi}]\left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right][-] \tag{3.55}$$

where EM_j are the emissions from mode j on a CO_2 equivalent basis.

3.7.3 Defaults for crude oil transport

Defaults for crude oil transport are generally taken from the CA-GREET model, with some modifications and simplifications applied. Defaults for surface operations are given below in Table 3.12.

Table 3.12: Default inputs for crude transport.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
C_j	Transport capacity of mode j	-	*'Crude Transport'* Table 2.1		[ton]	[14]	
e_m	Energy intensity of transport in mode j by energy unit transported	(3.50)	-	-	[Btu/MMBtu-mi]		
EF_{jki}	Emissions factor for fuel k, species i, mode j	-	*'Emissions Factors'* Table 1.5		[g/MMBtu]		a
EM_{ji}	Emissions of species i by mode j	(3.52)	-	-	[g/MMBtu-mi]		
EM_j	Emissions of all GHGs in CO_2 eq. units by mode j	(3.53)	-	-	[g CO_2 eq./MMBtu-mi]		
E_{TR}	Total energy use in transport	(3.54)	-	-	[Btu/MMBtu]		a
EM_{TR}	Total emissions from in transport	(3.55)	-	-	[g/MMBtu]		a
η_j	Efficiency of transport mode j	-	*'Crude Transport'* Table 2.3		[Btu/hp-hr]	[14]	
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1		[gCO_2eq./g]		
γ_o	Specific gravity of crude oil	-	0.876	0.8-1.05	[-]	[83]	
l_j	Load factor of mode j	-	*'Crude Transport'* Table 2.3		[%]	[14]	
$\lambda_{j_1 J_2}$	Fraction of technology j_2 used in mode j_1	-	*'Crude Transport'* Table 2.6		[%]	[14], Est.	
λ_{jk}	Fraction of fuel k used in mode j	-	*'Crude Transport'* Table 2.7		[-]	Est.	a
P_j	Power consumption of mode j	-	*'Crude Transport'* Table 2.2		[hp]	[14]	
ρ_w	Density of fresh water	-	350.4	-	[lb/bbl]	[113]	
U_j	Transport effectiveness in mode m	(3.49); (3.48)	-	-	[Btu/ton-mi]		
$U_{j_1 j_2}$	Transport effectiveness of propulsion tech j_2 used in mode j_1	-	*'Crude Transport'* Table 2.5		[Btu/ton-mi]	[14]	
v_j	Velocity of mode j	-	*'Crude Transport'* Table 2.3		[mi-hr]	[14]	

[a] Default crude oil shipment distance in CA-GREET is 750 mi for a one-way trip [14].

3.8 Bitumen extraction & upgrading

3.8.1 Introduction to bitumen extraction & upgrading

Bitumen extraction and upgrading is modeled separately from conventional oil extraction because the technologies applied differ. OPGEE v1.1 does not include process models as for bitumen extraction. Instead, OPGEE uses energy consumption and fugitive emissions data from GHGenius [10].

3.8.2 Calculations for bitumen extraction & upgrading

The OPGEE bitumen module tracks three hydrocarbon products: raw bitumen, synthetic crude oil, and hydrocarbon diluent. For each product, the API gravity, specific gravity (γ), and lower heating value (LHV) are generated. Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE. For bitumen and SCO, γ and LHV are derived from API gravity via formula or lookup [83]. The table of heating values as a function of API gravity does not account for composition differences between SCO of a given density and conventional crude of the same density. This introduces uncertainty of an unknown (though likely small) magnitude.

Fuel Specs Table 1.1

Diluent composition, density, and heating value are derived from tabulated diluent compositions [114]. Three diluent streams were selected from literature sources [114]. Hydrocarbon species are combined into bins (see notes in model) and the composition of diluent samples is plotted in Figure 3.15. Element fractions of C and H are calculated and the resulting heating value is calculated using the Dulong formula [113].

Bitumen Extraction & Upgrading Table 4.7

After specifying the properties of the hydrocarbon streams, production pathways are defined. First, the product is chosen as upgraded SCO or diluted bitumen:

Bitumen Extraction & Upgrading 2.6.1

$$y_{sco} \text{ or } y_{db} = 1 \tag{3.56}$$

where y is a binary variable representing a SCO product y_{sco} or a diluted bitumen product y_{db}.

Next, the primary extraction and (if applicable) upgrading technology pathway is defined:

Bitumen Extraction & Upgrading 2.6.2

- Bitumen mining with integrated upgrading, $y_{MI} = (0 \text{ or } 1)$
- Bitumen mining with non-integrated upgrading, $y_{MN} = (0 \text{ or } 1)$
- In situ production via non-thermal methods (e.g., production via cold heavy oil production with sand (CHOPS) or polymer flood), $y_{IP} = (0 \text{ or } 1)$
- In situ production via steam assisted gravity drainage (SAGD), $y_{IS} = (0 \text{ or } 1)$
- In situ production via cyclic steam stimulation (CSS), $y_{IC} = (0 \text{ or } 1)$

In this case, only one path can be chosen so the sum of binary pathway variables y_j must equal 1:

$$\sum_j y_j = 1 \qquad (j \in MI, MN, IP, IS, IC) \tag{3.57}$$

An important parameter is the fraction diluent blending rate λ_{db}. Dilbit blending rates depend on the input bitumen density, the quality of product being produced, and the relative market value of diluent and bitumen (i.e., heavy-light refining value differential).

Bitumen Extraction & Upgrading 2.8

The calculation of emissions from bitumen extraction and upgrading operations is based on energy intensities from GHGenius [10]. OPGEE estimates diesel, natural gas, electricity, coke, and still gas use. Values are derived from GHGenius as energy consumed, to avoid divergence due to varying energy densities.[2] GHGenius energy intensities are derived from industry-reported energy use [115].

Bitumen Extraction & Upgrading Table 4.1 - 4.4

The energy consumed of a given fuel type k per unit of energy produced is given by e_k:

$$e_k = e_{EX,k} + e_{UP,k} \qquad [\text{mmBtu/bbl SCO}] \tag{3.58}$$

where the primary resource extraction energy use $e_{EX,k}$ for fuel type k is equal to:

Bitumen Extraction & Upgrading 3.1.1

$$e_{EX,k} = y_{sco}\left(\sum_j y_j e_{EX,jk}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\right)(1-\lambda_{db}) \tag{3.59}$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}]$$

where in this equation $e_{EX,jk}$ = specific energy use in extraction pathway j of fuel type k [mmBtu/bbl bitumen]; ΔV_{UP} = volumetric gain upon upgrading [bbl SCO/bbl bitumen]; and λ_{db} = fraction of diluent blended into the dilbit product. Depending on whether y_{sco} or y_{db} is equal to 1, only one of these sums is performed. If the bitumen is upgraded, the energy consumed per bbl of bitumen mined is reduced by the factor $1/\Delta V_{UP}$ because 1 bbl of bitumen results in the production of more than 1 bbl of SCO. In the case of blended dilbit, the energy consumed per bbl of bitumen is reduced by the factor (1-λ_{db}) because the dilbit contains diluent in addition to bitumen.

For modeling natural gas consumption, a special consideration is made for the steam oil ratio. In this case:

Bitumen Extraction & Upgrading 3.1.1.2

$$e_{EX,ng} = y_{sco}\left(\sum_j y_j e_{EX,jk}\frac{SOR_j}{SOR_{j0}}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\frac{SOR_j}{SOR_{j0}}\right)(1-\lambda_{db})$$

$$(j \in MI, MN, IP, IS, IC)$$

[2] For example, natural gas heating values are quite variable between GHGenius and GREET per scf of gas

(3.60)

where SOR_j = steam oil ratio observed in pathway j and SOR_{j0} = default SOR in that pathway. In pathways without steam injection,the SOR term is equal to 1. Energy demand in thermal extraction will scale nearly linearly with steam injection rates because of the increase in steam energy consumption and increase in fluid handling energy requirements with increasing SOR [1, 9].

Energy of type k consumed in upgrading is modeled using the following function:

Bitumen Extraction & Upgrading 3.1.2

$$e_{UP,k} = y_{sco}\left(\sum_{\forall j \neq MI} y_j e_{UP,jk} + y_{MI}\left(e_{UP,MI,k} - \frac{e_{EX,MN,k}}{\Delta V_{UP}}\right)\right) \tag{3.61}$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}]$$

Where $e_{UP,k}$ is energy consumption of fuel type k for stand alone upgrading, and $e_{UP,MI,k}$ and $e_{EX,MN,k}$ are energy use of type k for integrated mining and upgrading and non-integrated mining. Therefore, the upgrading energy consumption for an integrated operation is modeled as the difference between an integrated mining and upgrading operation and the volumetric gain adjusted energy consumption for a stand-alone mining operation.

Venting, flaring and fugitive emissions are calculated using volumetric dilbit and SCO adjustments as above. As with conventional pathways in OPGEE, country-level average satellite flaring rates for Canada are applied to oil sands operations. This is done because of preference for the verifiable nature of satellite-derived data. For fugitive emissions, tabulated fugitive emissions factors from GHGenius are used as reported in GHGenius documentation [115].

Bitumen Extraction & Upgrading 3.2

External energy requirements are tabulated from total net energy inputs by making the following default assumptions about internal vs. external fueling of oil sands projects :

Bitumen Extraction & Upgrading 2.9

- Diesel, coke, and still gas consumed are generated onsite in upgraders or purchased from other local oil sands operations. This is generally the case due to the remote location of the oil sands operations;
- Natural gas and net electricity demand (on site consumption less on site generation) are purchased from external operations.

Using these assumptions, net energy requirements from the external energy system are computed. These net inputs are used to generate off-site emissions credits or debits from oil sands operations. Because diluent is typically a natural gas condensate, diluent consumed is counted as external natural gas production. In order to maintain congruence with other OPGEE pathways, upstream fuel cycle emissions are used from GREET.

Bitumen Extraction & Upgrading 3.3

Bitumen Extraction & Upgrading 3.3.1.6

Total net energy consumed and fugitive emissions, per bbl of output hydrocarbon product produced (e.g., diluted bitumen or SCO), are integrated with the overarching OPGEE emissions calculation framework.

Fuel Cycle Tables 1.2, 1.4

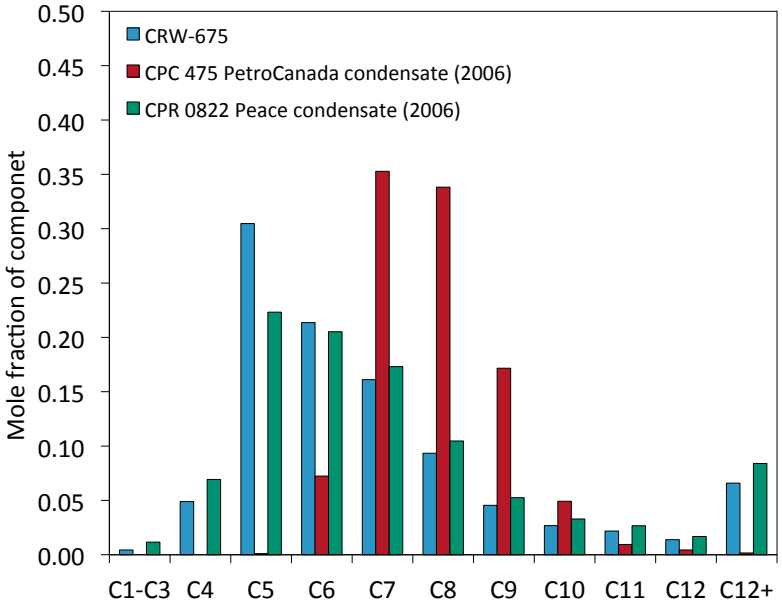

Figure 3.15: Composition of three diluent products from C1 to C12+ hydrocarbons.

Land use emissions from bitumen extraction operations are calculated similarly to those from conventional oil operations [75]. See Section 3.2 for a detailed description.

Bitumen Extraction & Upgrading 3.5

3.8.3 Defaults for bitumen extraction

The complete list of model terms, along with default values (if applicable) are included for all parameters in Table 3.13.

Table 3.13: Default inputs for bitumen extraction & upgrading calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$^\circ API_{db}$	API gravity of bitumen	-	8	4 - 12	[-]	[10]	
$^\circ API_{sco}$	API gravity of SCO	-	32	20 - 34	[-]	[10]	
$^\circ API_{dl}$	API gravity of diluent	-	59.4	55 - 63	[-]	[114]	
$e_{EX,k}$	Cons. of fuel k in extraction	(3.59)	-	-	[mmBtu/bbl]	-	
$e_{EX,j,k}$	Cons. of fuel k pathway j in extraction	-	var.	-	[mmBtu/bbl]	[10]	a
$e_{UP,k}$	Cons. of fuel k in upgrading	(3.61)	-	-	[mmBtu/bbl]	-	
$e_{UP,j,k}$	Cons. of fuel k for pathway j in upgrading	-	var.	-	[mmBtu/bbl]	[10]	a
e_k	Total cons. of fuel k in bitumen extraction & upgrading	(3.58)	-	-	[mmBtu/bbl]	-	
λ_{db}	Diluent blending fraction in dilbit	-	0.33	0.15 - 0.5	[%]	[114, 116]	
SOR_{IS}	Steam oil ratio, SAGD	-	3.0	2.5 - 5	[bbl steam/bbl bit]	[117]	
SOR_{IC}	Steam oil ratio, CSS	-	3.9	3.5 - 6	[bbl steam/bbl bit]	[117]	
SOR_{IS0}	Default steam oil ratio, SAGD	-	3.0		[bbl steam/bbl bit]	[117]	
SOR_{IC0}	Default steam oil ratio, CSS	-	3.9		[bbl steam/bbl bit]	[117]	
ΔV_{UP}	Volumetric gain upon upgrading	-	1.17	Unknown	[bbl SCO/bbl bitumen]	[10]	b
y_{sco}	Binary var. for producing SCO	-	1	0 or 1	[y/n]		c
y_{db}	Binary var. for producing diluted bitumen	-	0	0 or 1	[y/n]		c
y_{MI}	Binary var. for integrated mine & upgrade	-	1	0 or 1	[y/n]		d
y_{MN}	Binary var. for non-integrated mine & upgrade	-	0	0 or 1	[y/n]		d
y_{IP}	Binary var. for in situ, primary	-	0	0 or 1	[y/n]		d
y_{IS}	Binary var. for in situ, SAGD	-	0	0 or 1	[y/n]		d
y_{IC}	Binary var. for in situ, CSS	-	0	0 or 1	[y/n]		d

[a] Data are presented in OPGEE tables 'Bitumen Extraction & Upgrading' worksheet.
[b] Volumetric gain upon upgrading is based on 1:1 mass throughput rate for bitumen to SCO [10] and reduction in density from 8 to 32 °API.
[c] The most common pathway for bitumen production is mining and upgrading to synthetic crude oil, so upgrading is selected by default.
[d] The most common pathway for bitumen production is integrated mining and upgrading to synthetic crude oil, so y_{mi} is chosen by default.

4 Supplemental calculations worksheets

4.1 Gas balance

This worksheet tracks the gas balance across the process stages and ensures that gas is conserved in the system. Due to the complexity of allocating VFF emissions some simplifications were made to the overall structure of the system.

The gas-to-oil ratio (GOR) is defined as the total gas evolved while reducing the oil to atmospheric pressure divided by the volume of the remaining crude oil [47]. The GOR is used to calculate the volume of the produced gas stream. The total GOR depends on the crude oil, on the number of stages used in the oil-gas separation sequence, as well as the operating pressure of each stage [47]. The GOR and the associated gas composition is calculated after three or more separation stages when the GOR approaches a limiting value. Fugitives from active wells, well cellars, and well maintenance events (such as well workovers and cleanups) are assumed to occur upstream from surface separation. Therefore these emissions sources do not affect the volume and composition of the initial produced gas stream in the gas balance.

Gas Balance Table 1.1

The flaring of associated gas is assumed to occur upstream of the gas processing stage. Although the accumulation of gases to flare likely occurs at various points throughout the process, the flared gas is modeled as being flared before gas processing in OPGEE. This allows for an added flexibility in OPGEE to account for early field production or production in locations without a gas market. For these situations, no surface processing occurs and all produced gas is flared.

Gas Balance Table 1.2

Gas processing is presented in the gas balance as one process stage which includes gas treatment and dehydration as well as all the fugitives and venting of associated gas in these two processes system. These fugitive emissions do not include the venting from crude oil storage tanks. The associated gas GOR is computed at the last stage in the surface oil-gas separator. In reality the gas dehydrator can process both sweet and sour gases. The simplification of gas processing into one stage eliminates the need to determine which gas processing unit comes first (AGR unit or gas dehydrator). Accordingly, no differentiation is made between the inlet gas volumes of the gas treatment and gas dehydration units.

Gas Balance Table 1.4

A user control is placed at the composition of the inlet gas to the gas processing stage to make sure that the total fugitives and venting of associated

gas components (i.e., CO_2, CH_4, and C2+) are conserved in the gas stream. In the event of "ERROR" the user has to increase either the molar fraction of the gas component or the GOR.

Gas Balance Table 1.7

The last stage in the gas balance before the generation of the product gas is the demethanizer where heavy gas components (C3+) are condensed and produced as natural gas liquid (NGL). The product NGL left after the use of NGL as a process fuel is either added to the crude oil output to increase its market value or exported. The export of NGL incurs a GHG emissions credit. The user determines the proportion of each gas component that is condensed in the demethanizer in the *'Surface Processing'* worksheet. The default assumption is 50% ethane, 100% propane, and 100% butane.

The volume of lifting gas, if applicable, is subtracted from the volume of product gas stream to calculate the volume of gas remaining for use as a process fuel and/or re-injection into the reservoir for pressure maintenance. Any product gas left after supplying the process fuel requirements and gas re-injection is exported.

4.2 Steam injection for thermal oil recovery

4.2.1 Introduction to steam injection

Steam injection for thermal enhanced oil recovery (TEOR) is practiced globally, with significant operations in California, Alberta, Indonesia, and Venezuela [118]. Steam injection reduces the viscosity of heavy crude oils by multiple orders of magnitude, even with relatively small temperature increases [9, 56, 59, 119, 120]. This viscosity reduction results in improved flow characteristics and improved reservoir sweep [59]. Many fields that would not produce economic volumes of hydrocarbons without steam injection become large producers after steam injection.

4.2.2 Calculations for steam injection

Steam generation for thermal oil recovery is modeled using two technologies: steam generation via once-through steam generators (OTSG) (Figure 4.1) and steam and electricity co-production via gas turbine and heat recovery steam generator (HRSG) combination (4.3).

Steam Injection 1.1.6

4.2.2.1 Steam system properties

The quantity of steam required is given by the oil production rate and the steam oil ratio:

Steam Injection 1.2.4

$$Q_{ws} = SOR\rho_w Q_o \qquad \left[\frac{\text{lbm water}}{\text{d}}\right] \tag{4.1}$$

Where Q_{ws} = steam required to be generated per day [lbm water/d]; SOR = steam oil ratio [bbl steam as cold water equivalent/bbl water]; ρ_w = density of water [lbm/bbl]; and Q_o = quantity of oil produced [bbl/d]. Steam quantities are measured as volume of cold water equivalent.

The enthalpy of steam generated ($h_{ws} = h_{ws}(p_{ws}, T_{ws})$) at steam quality X_{ws}, steam pressure p_{ws}, saturated steam temperature T_{ws} is given by:

Steam Injection 1.2.13

$$h_{ws} = h_{ws,g}X_{ws} + h_{ws,f}(1 - X_{ws}) \quad \text{where} \quad h_{ws} = h_{ws}(p_{ws}, T_{ws}) \qquad \left[\frac{\text{Btu}}{\text{lbm}}\right] \tag{4.2}$$

Steam temperature T_{ws} [°F] is tabulated for saturated steam as a function of saturation pressure p_{ws} [psia] (assuming that pressure is the controlled variable) [121]. Because we are using steam tables rather than direct computation, steam pressure is rounded before lookup. $h_{ws,g}$ = enthalpy of vapor phase water at p_{ws} [Btu/lbm] while $h_{ws,f}$ = enthalpy of saturated water at p_{ws} [Btu/lbm].

Input Data Table 5.3

Steam is generated at sufficient pressure to ensure that it will flow into the subsurface (eliminating the need for wellhead compressors). Due to friction and thermal losses in piping and wellbore, the steam pressure drops before reaching the reservoir:

Steam Injection 1.2.8

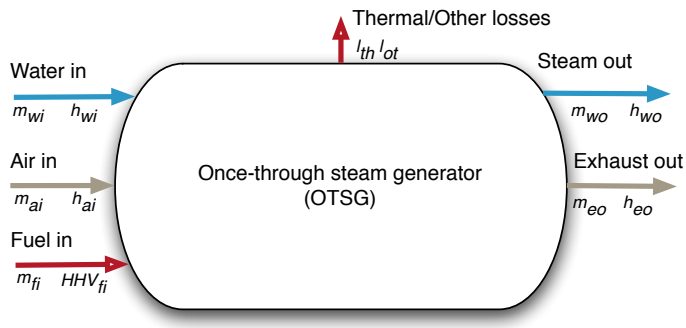

Figure 4.1: Once-through steam generator with mass and energy balance terms. Lower case terms are defined per lbmol of input fuel.

$$p_{ws} = p_{res}\epsilon_{ws} \qquad [\text{psia}] \tag{4.3}$$

where ϵ_p = pressure loss factor which is ≥ 1 [psia generator/psia reservoir]. Chilingarian et al. [38, p. 228] note that 10-50% of the pressure in the steam at steam generator outlet can be lost by the time the steam reaches the reservoir.

Steam quality X_{ws} [lbm vapor/lbm steam] is governed by the needs of the project. Higher steam qualities impart more energy into the formation, but steam quality is limited by the steam generator configuration. Once-through steam generators cannot generate 100% quality steam because of deposition of solids in boiler tubes. In practice, ≈20% of water mass is left in fluid state to carry solutes ($X_{ws} \approx 0.8$) [122].

The enthalpy increase of water is given by the difference between water inlet enthalpy and exit enthalpy:

Steam Injection 1.2.14

$$\Delta h_{ws} = h_{ws} - h_{w,in} \qquad \left[\frac{\text{Btu}}{\text{lbm water}}\right] \tag{4.4}$$

Where $h_{w,in}$ is water inlet enthalpy [Btu/lbm] for compressed water enthalpy at inlet water pressure $p_{w,in}$ and inlet water temperature $T_{w,in}$ [121]. Inlet pressure is assumed equal to required steam outlet pressure (e.g., no pressure gradient in boiler).

Input Data Table 5.4

4.2.2.2 Once-through steam generator modeling (OTSG)

Once-through steam generators are modeled [9, 122], as shown in Figure 4.1. Fuel inputs include pipeline quality natural gas, produced gas, or produced crude oil. A binary choice is required for gaseous or liquid fuels. For gaseous fuels, a mixture of produced gas and purchased gas is allowed.

Steam Injection 2.1.1, 2.1.2

The operating conditions of combustion must be specified. These include the inlet air temperature $T_{a,in}$ [°F], the outlet exhaust temperature $T_{e,out}$ [°F] and the excess air in combustion $R_{a,comb}$ [mol O_2/ mol stoichiometric O_2].

Gaseous fuel combustion for steam generation The gas species tracked in the OTSG are described below in Section 6.4. For an arbitrary fuel makeup, the composition, average molar mass, and lower heating value (LHV) are calculated.

Steam Injection 2.3.1

OTSG inlet air composition, combustion stoichiometry, and excess air ratio are used to compute the mass of air required per lbmol of fuel consumed. For each reactive species, the reactants needed per mol of input fuel are computed:

Fuel Specs Table 2.3

$$N_i = \frac{x_{a,i}}{x_{a,O2}} \left(x_{f,C} + \frac{x_{f,H}}{4} \right) \qquad \left[\frac{\text{lbmol}}{\text{lbmol fuel}} \right] \tag{4.5}$$

where N_i = number of moles of air species i [mol]; x_a, i = mole fraction of species i in air [mol/mol]; $x_{f,C}$ = mol of carbon per mol of fuel (e.g., 2 for C_2H_6) [mol/mol]; and $x_{f,H}$ = mol of hydrogen per mol of fuel [mol/mol]. The sum over all species i gives air required for stoichiometric combustion, which is multiplied by the excess air ratio $R_{a,comb}$ to get real air requirements:

Steam Injection 2.4.3.1

$$N_a = R_{a,comb} \sum_{i=1}^{n} N_i \qquad \left[\frac{\text{lbmol air}}{\text{lbmol fuel}} \right] \tag{4.6}$$

Where $R_{a,comb}$ = ratio of combustion air to stoichiometric air [lbmol air / min lbmol air for combustion]. In this case there are n species present in air.

At constant pressure the change in enthalpy with temperature is given as:

$$\delta h = C_p \delta T \qquad \left[\frac{\text{Btu}}{\text{lbmol}} \right] \tag{4.7}$$

Specific heat capacity C_p as a function of T can be defined for gas species i as [123, Table A-2E]:

$$C_{p,i} = a_i + b_i T + c_i T^2 + d_i T^3 \qquad \left[\frac{\text{Btu}}{\text{bmol-}^\circ\text{R}} \right] \tag{4.8}$$

Which can be integrated between outlet and inlet temperatures

$$h_i = \int_{T_{in}}^{T_{out}} C_{p,i} dT = a_i + \frac{b_i}{2} T^2 + \frac{c_i}{3} T^3 + \frac{d_i}{4} T^4 + e_i \qquad \left[\frac{\text{Btu}}{\text{lbmol}} \right] \tag{4.9}$$

where e_i is a constant of integration. OPGEE sets h = 0 at T = 300 K to solve for e_i. Terms a through d are given in OPGEE for N_2, O_2, CO_2, SO_2, air, $H_2O_{(v)}$ and fuel inputs (approximated as CH_4) [123].

Input Data Table 4.1

For example, inlet air enthalpy is computed using the inlet air temperature:

Input Data Table 4.1 - 4.6

$$h_{a,in} = \sum_{i=1}^{n} \left(a_i T_{a,in} + \frac{b_i}{2} T_{a,in}^2 + \frac{c_i}{3} T_{a,in}^3 + \frac{d_i}{4} T_{a,in}^4 + e_i \right) \qquad \left[\frac{\text{Btu}}{\text{lbmol air}} \right] \tag{4.10}$$

where again we have $i \in 1 \ldots n$ components in air.

The outlet lbmol of all gases per lbmol of fuel consumed are computed

Steam Injection 2.5.1.1

assuming complete combustion (e.g., no unburned hydrocarbons, no CO produced), and no reactions with nitrogen.

The enthalpy of OTSG outlet exhaust $h_{e,out}$ is computed with eq. (4.10), using user input OTSG exhaust outlet temperature $T_{e,out}$. In practice, efficient steam generation is achieved by reducing $T_{e,out}$ to as low as practicable, thus removing as much heat as possible from OTSG combustion products. $T_{e,out}$ has a lower limit due to the need to avoid condensing corrosive flue gas moisture onto heat transfer tubes [122]. *Steam Injection 2.5.1.4*

A wide range of exhaust gas temperatures is cited. Buchanan et al. cite ideal (minimum) exhaust gas temperatures of 266 °F [130 °C] or higher [124, p. 78]. Other sources cite temperatures of 350 °F [120, p. 36], 400 °F [38, p. 227] and even greater than 550 °F for older Russian units [119, p. 181]

In some cases, the exhaust gas temperature is limited by the approach to the inlet water temperature. In SAGD operations hot produced water is used as inlet water, and $T_{e,out}$ comes to within 15 °C of the inlet water temperature. An air preheater would allow utilization of this excess energy if hot produced fluids are used for water source [124].

In addition to losses from flue gas exhaust, other losses occur in an OTSG. We lump all thermal losses into a thermal shell loss term. For simplicity, it is assumed that 4% of fuel enthalpy is lost as thermal shell loss ϵ_{th} [Btu/lbmol fuel consumed]. Other losses (start up inefficiencies, fouling, etc.) ϵ_{ot} are assumed ≈1% of the fuel LHV [Btu/lbmol fuel consumed]. These total losses are supported by references, which cite losses of approximately 4% [122]. *Steam Injection 2.6.2, 2.6.3*

The enthalpy available for transfer to the incoming water is given by the difference between incoming enthalpy sources (incoming combustion air, fuel inputs) and outgoing enthalpy sources (hot exhaust, shell losses, other losses):

$$\Delta h_{comb} = LHV + h_{a,in} - h_{e,out} - \epsilon_{th} - \epsilon_{ot} \qquad \left[\frac{\text{Btu to water}}{\text{lbmol fuel}}\right] \tag{4.11}$$

Steam Injection 2.6.4

The efficiency of steam generation η_{OTSG} (LHV basis) can be computed by comparing the enthalpy imparted on steam to the higher heating value of the fuel inputs:

$$\eta_{OTSG} = \frac{\Delta h_{comb}}{LHV} \qquad \left[\frac{\text{Btu to steam}}{\text{Btu fuel}}\right] \tag{4.12}$$

Steam Injection 2.6.5

Using the enthalpy provided to steam and ΔH_{comb}, the total fuel consumption rate required per day can be computed.

$$m_f = \frac{Q_{ws}\Delta h_{ws}}{\Delta h_{comb}} \qquad \left[\frac{\text{lbmol fuel}}{\text{d}}\right] \tag{4.13}$$

Steam Injection 2.7.2

Liquid fuels for steam generation Liquid fuels can be used for steam generation. In general, these are produced heavy crude oils that are consumed on site for steam generation. This was common practice in California TEOR developments until the 1980s, when air quality impacts stopped the practice.

Table 4.1: Hydrogen constant a_H as a function of API gravity.

API gravity	a_H
0 - 9	24.50
10 - 20	25.00
21 - 30	25.20
31 - 45	25.45

Because liquid fuels do not have consistent molar compositons, computations generate lbm of fuel consumed. The heating value of crude oil as a function of API gravity is tabulated [83]. The bulk chemical composition of crude oil is calculated [83, p. 41]. The mass fraction hydrogen w_H as a function of crude specific gravity sg is given as:

Fuel Specs Table 1.1

Fuel Specs Table 1.2

$$w_H = a_H - 15\gamma_o \qquad [\text{mass frac. H}] \tag{4.14}$$

Where a_H is a constant that varies with crude API gravity (and therefore specific gravity) as show in Table 4.1.

The mass fraction of sulfur and other contaminants decreases with increasing API gravity, as seen in Figure 4.2 [125, Ch. 8, tables 3, 4] [125, Ch. 7, tables 2, 3, and 19] [126]. We therefore include default values of w_S that vary with API gravity from 5 wt.% (API gravity 4-5) to 0.5 wt.% (API gravity greater than 35). Nitrogen and oxygen content $w_N + w_O$ is assumed constant at 0.2 wt.% and in element balance it is assumed to be entirely made up of N. Mass fraction carbon w_C is calculated by difference using above mass fractions. Using the relative molar proportions of C, H, S, and N, the stoichiometric oxygen demand per carbon atom is computed assuming complete combustion.

Fuel Specs Table 1.2

Using the oxygen requirement for combustion and the excess air ratio $R_{a,comb}$, the lbmol of air required is computed similarly to eq. (4.6) above. The inlet air enthalpy for combustion is computed using eq. (4.10) above. The outlet exhaust composition is computed via element balance assuming complete oxidation (including S to SO_2). The outlet exhaust enthalpy is computed as in eq. (4.10) for gaseous fuels combustion. The energy balance for combustion of liquid fuels is computed as in eq. (4.11).

Steam Injection 2.4.4

4.2.2.3 Gas turbine with heat recovery steam generator

Cogeneration is used to co-produce electricity and steam for thermal oil recovery. These systems combine a gas turbine (GT) with a heat recovery steam generator (HRSG) to produce steam from the exhaust gas of the gas turbine (see Figure 4.3).

Gas turbine modeling The chemical kinetics software tool Cantera [127] is used with MATLAB to compute the efficiency, losses, and turbine exit temperature for four hypothetical gas turbines labeled A, B, C, and D. The general method is as follows:

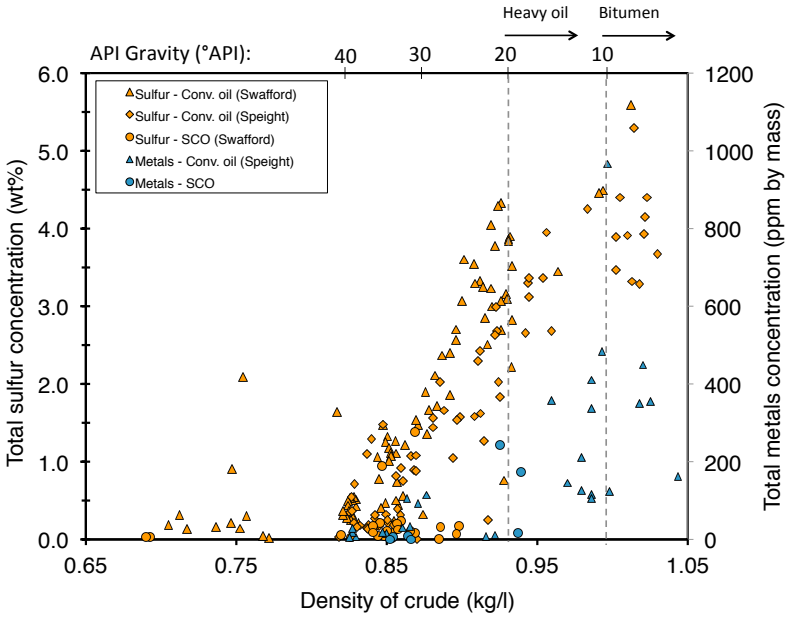

Figure 4.2: Increase of crude contaminant load with increase in crude specific gravity (decrease in API gravity). Data from: Speight (1994) and Swafford (2009).

- Fuel and air compositions are specified in OPGEE for purchased natural gas (95% CH_4, 3% C_2H_6, 1.5% C_3H_8, and 0.5% inert) and air (dry air with 2% moisture).
- The LHV of the fuel is computed assuming complete combustion.
- Using the excess air fraction for a given turbine, the amount of O_2 (and therefore air) required relative to stoichiometric air requirements is used to compute relative air and fuel inputs into a mixture. The masses of fuel inputs $m_{f,in}$ and air inputs $m_{a,in}$ are normalized to a 1 kg mixture, as is default in Cantera.
- The fuel and air mixture is equilibrated using the assumption of adiabatic combustion.
- The enthalpy of products of adiabatic combustion is recorded as h_e, or the mass-specific enthalpy after combustion.
- The enthalpy of products of combustion is computed when returned to initial conditions (300 K, 101.325 kPa) to compute the reference enthalpy $h_{e,atm}$.
- The difference between the enthalpy of hot combustion products and the reference enthalpy of completely cool exhaust is partitioned into losses (pressure and temperature losses due to real machine imperfections), work provided by turbine (W_{GT}), and enthalpy of hot exhaust ($h_{e,out}$).

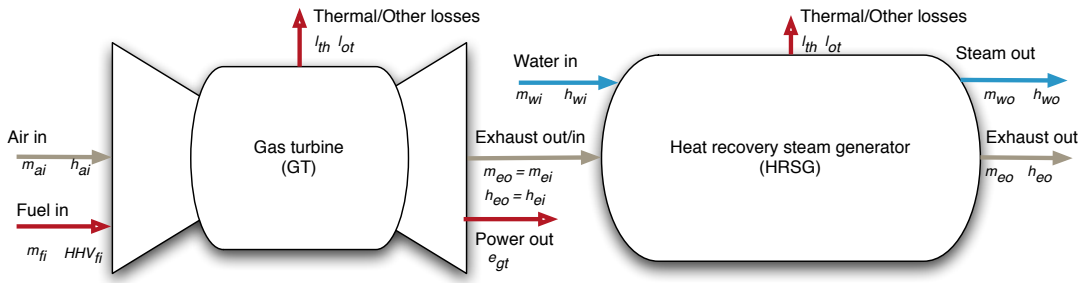

Figure 4.3: Gas turbine plus heat recovery steam generator model. Mass flows represented by m and energy flows represented by fuel lower heating value (LHV), electric power out (e) and enthalpy of gases (h).

- The resulting temperature of hot exhaust gases is computed.

The gas turbine model was tested against reported gas turbine data. Data for turbine heat rate, power output, turbine exhaust mass flow rate, and turbine exhaust temperature were collected for commercial turbines from Siemens, GE, and Hitachi [128–130]. The code assumes consistent 4% thermal and other losses ($\epsilon_{th} + \epsilon_{ot}$) for each turbine. Results show excellent agreement between predicted turbine exhaust temperature and manufacturer-reported turbine exhaust temperatures (Figure 4.4).

The GT model is used to model four hypothetical turbines A - D, using characteristics similar to those specified by Kim [131]. The results from our code are used to generate required inputs for turbines A-D including turbine exhaust temperature [F], turbine efficiency [Btu e- per Btu LHV fuel input], turbine specific power [Btu e-/lb exhaust], turbine excess air [lbmol O_2 / lbmol stoichiometric O_2], and turbine loss factor [Btu/Btu LHV fuel input]. These results are shown in Table 4.2.

Input data Table 3.1

Using turbine efficiency and turbine loss from Table 4.2, energy balances for each turbine are computed. Using turbine excess air ratios from Table 4.2, total air requirements per lbmol of fuel input to gas turbine are computed. Inlet air enthalpy is computed as shown in eq. (4.10). Moles of combustion products are computed via stoichiometric relationships. Using turbine exhaust temperature, turbine exhaust composition, and relationships from eq. (4.10), the enthalpy of gas turbine exhaust is computed.

Steam Injection 4.3.1

Steam Injection 4.3.4.4

Steam Injection 4.3.5.2

The enthalpy of the gas turbine exhaust is the useful energy input to the HRSG. Steam production via the HRSG is modeled analogously to that of the OTSG.

Steam Injection 4.3.5.7

4.2.3 Defaults for steam injection

4.2.3.1 General default parameters

Parameters and variables in the steam injection model are listed below in Table 4.3.

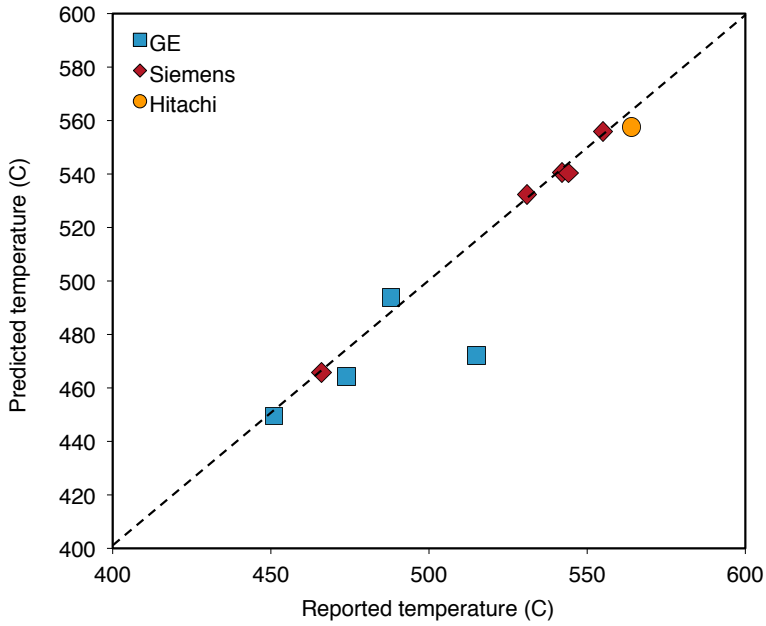

Figure 4.4: Predicted turbine exit temperatures for variety of turbines from literature (*y-axis*) as compared to reported value from the literature (*x-axis*).

Table 4.2: Gas turbine model results for hypothetical turbines A-D. These results serve as input data to OPGEE GT model.

Parameter	Unit	Turb. A	Turb. B	Turb. C	Turb. D
Turbine exhaust temp.	[°F]	932.0	947.9	950.0	1074.1
Turbine efficiency	$\left[\frac{\text{Btu e-}}{\text{Btu LHV}}\right]$	0.205	0.237	0.280	0.324
Turbine specific power	$\left[\frac{\text{Btu e-}}{\text{lb exhaust}}\right]$	69.5	85.4	108.0	155.7
Turbine excess air	$\left[\frac{\text{Mol } O_2 \text{ real}}{\text{Mol } O_2 \text{ stoich.}}\right]$	4.00	3.75	3.50	2.80
Turbine loss	$\left[\frac{\text{Btu loss}}{\text{Btu LHV}}\right]$	0.041	0.036	0.032	0.027

Table 4.3: Default inputs for steam injection calculations.

Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
a_H	Crude hydrogen fraction constant	-	Table 4.1	-	[lbm H / lbm crude oil]	[83]	
$a_i \ldots e_i$	Species-specific heat capacity constants	-	var.	-	[various]	[123]	
C_p	Heat capacity at constant pressure	(4.8)	-	-	[Btu/lbmol-°R]		
η_{OTSG}	OTSG efficiency	(4.12)	-	-	[Btu steam / Btu LHV fuel]		
ϵ_{th}	Thermal losses from OTSG	-	0.04	-	[Btu/Btul fuel]	[122]	
$\epsilon_{ot,ng}$	Other losses from OTSG fueled with natural gas	-	5000	-	[Btu/lbmol fuel]	[122]	c
$\epsilon_{ot,co}$	Other losses from OTSG fueled with crude oil	-	250	-	[Btu/lbml fuel]	[122]	c
ϵ_{ws}	Steam pressure loss factor	-	1.25	0.1 - 0.5	[frac.]	[38]	d
λ_{ng}	Fraction natural gas	-	1	0 - 1	[frac]	-	b
λ_{pg}	Fraction processed associated gas	-	0	0 - 1	[frac]	-	b
$h_{a,in}$	Inlet air enthalpy	(4.10)	-	-	[Btu/lbmol]		
$h_{e,out}$	Enthalpy of OTSG exhaust	(4.10)	-	-	[Btu/lbmol]		
$h_{ws,f}$	Enthalpy of liquid phase water in steam	-	var.	180 - 730	[Btu/lbm]		
$h_{ws,g}$	Enthalpy of vapor phase water in steam	-	var.	1090 - 1205	[Btu/lbm]		
h_{ws}	Enthalpy of injected steam ($<$ 100% quality)	(4.2)	-	-	[Btu/lbm]		
$h_{w,in}$	Inlet water enthalpy	-	9.8	-	[Btu/lbm]		
Δh_{ws}	Change in water enthalpy upon boiling	(4.4)	-	-	[Btu/lbm]		
Δh_{comb}	Heat available from combustion to water	(4.11)	-	-	[Btu / lbmol fuel]		
h_i	Enthalpy of species i	(4.9)	-	-	[Btu/lbmol]		
LHV	Lower heating value of fuel	-	var.	-	[Btu LHV / lbmol fuel]		
N_i	Number of moles of air species i	(4.5)	-	-	[lbmol]		
N_a	Number of moles of air for real (non-stoichiometric) combustion	(4.6)	-	-	[lbmol]		

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
$p_{w,in}$	Inlet water pressure	-	$= p_s$	-	[psia]		
p_{ws}	Steam pressure	(4.3)	-	-	[psia]		
Q_o	Quantity of oil produced	-	1000	-	[bbl oil/d]		
Q_{ws}	Steam required	(4.1)	-	-	[lbm water/d]	-	
$R_{a,comb}$	Excess air combustion ratio	-	1.2	1.075 - 1.25	[lbmol air/lbmol air stoich.]		e
ρ_w	Density of water	-	350.4	-	[lbm/ft^3]	[113]	f
γ_o	Crude specific gravity	(3.3)	-	-	[-]		
SOR	Ratio of steam injected to oil produced	-	3.0	2.5 - 6	[bbl water/bbl oil]	[98, 117]	g
$T_{a,in}$	Inlet air temperature	-	540	500 - 560	[°R]		h
$T_{e,out}$	Temperature of OTSG exhaust	-	810	725 - 910	[°R]	[various]	i
$T_{w,in}$	Inlet water temperature	-	40	-	[°F]		j
T_{ws}	Steam temperature	-	var.	-	[°F]		
w_H	Mass fraction hydrogen in crude	(4.14)	-	-	[lbm H / lbm oil]		
$x_{a,i}$	Mole fraction of species i in air	-	var.	-	[lbmol/lbmol]		m
x_C	Moles of carbon per mole of fuel	-	var.	-	[lbmol/lbmol]		a
x_H	Moles of hydrogen per mole of fuel	-	var.	-	[lbmol/lbmol]		a
X_s	Steam quality	-	0.8	-	[lbm vap./lbm steam]	[59]	k
y_{ng}	Binary variable: gaseous fuel in OTSG?	-	1	0 or 1	[y/n]	-	l
y_{co}	Binary variable: crude oil in OTSG?	-	0	0 or 1	[y/n]	-	l

a - See *'Fuel specs'* Table 2.3 for combustion factors for gas inputs.
b - Assumption: Gas is purchased due to typical low GORs for heavy crudes.
c - Assumption to account for incomplete combustion, fouling, warm up and cool-down, and other real-world inefficiencies.
d - Piping friction losses can represent 10-50% of the steam pressure developed at the outlet of the steam generator." [38, p. 228]
e - Conservative assumption for input excess air. Can be lower with special combustion equipment.
f - Fresh water input
g - Common SOR for efficient TEOR project. Range is quite variable, especially in early years of steam injection.
h - Equal to 300 K. Chosen for ease of gas turbine modeling.
i - Equal to 350 °F. Reported range is wide in literature. See [38, 119, 120, 124].

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes

j - Assumption for cool water inlet.
k - Most commonly cited steam quality. Other qualities cited include 75%.
l - Assumption: Most steam generation in California and Alberta is natural gas fired.
m - See *'Input Data'* Table 2.4 for air composition.

Table 4.4: Indicators of SOR distributions for California and Alberta thermal EOR production.

	Mean - SOR_t	Mean - SOR_i
California - 2009	3.32	4.29
California - 2010	3.41	Unk.
Alberta - 2009	3.58	NA
Alberta - 2010	3.32	NA

4.2.3.2 *Default for steam-oil-ratio (SOR)*

Because the SOR is a key parameter driving GHG emissions from thermal oil production operations, we examine default values for SOR in more detail.

SOR data are collected for California and Alberta thermal oil recovery operations for 2010 and 2011 [98, 106, 117, 132, 133].

For California operations, incremental SOR is calculated for 2009 using volumes of steam injected and reported incremental production due to steam injection. 'Total' SOR is also calculated for 2009 using total production by field and total steam injection. For 2010, only monthly data are available, so incremental production data are not available. Therefore, only total SOR is reported.

For Alberta operations, data on bitumen produced and steam injected were collected for 24 thermal recovery projects (SAGD and CSS). No data were available on incremental rather than total production, and it is not clear what incremental production figures would represent bitumen operations where non-enhanced production would be very small.

Production volumes are binned by SOR for both regions and reported in Figure 4.5. Averages for SOR are presented in Table 4.4.

4.3 Electricity

The *'Electricity'* worksheet calculates the energy consumption of onsite electricity generation. The *'Electricity'* worksheet does not include electricity cogeneration in steam generation system. Available generation technologies include natural gas generator set, natural gas turbine, and diesel generator set. The user enters the capacity of onsite electricity generation as a fraction of the electricity required. The fraction of electricity above 1.0 is exported. In the *'Electricity'* worksheet the amount of electricity generated onsite is calculated as:

$$E_{el,gen} = \lambda_{el} \cdot E_{el,req} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{4.15}$$

where $E_{el,gen}$ = onsite electricity generation [MMBtu/d]; λ_{el} = fraction of required electricity generated onsite; and $E_{el,req}$ = electricity required. The electricity required is calculated in the *'Energy Consumption'* worksheet.

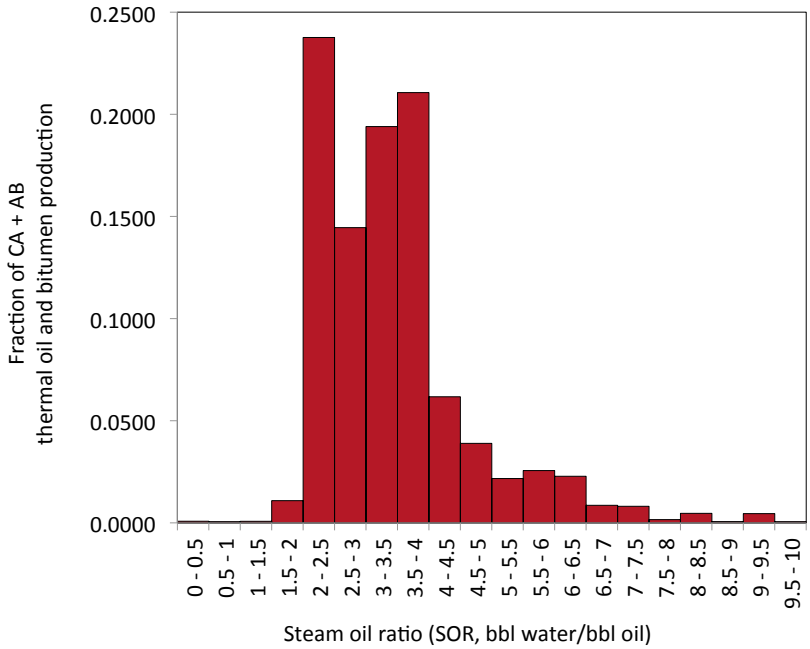

Figure 4.5: Distribution of SOR values for California and Alberta thermal EOR projects (steamflood, cyclic steam stimulation, steam-assisted gravity drainage).

The energy consumption of the generator is calculated from the appropriate driver in the *'Drivers'* worksheet as:

$$e_{GS} = \frac{e_D}{0.75\eta_G} \qquad \left[\frac{\text{Btu}}{\text{kWh}}\right] = \frac{\left[\frac{\text{Btu}}{\text{bhp-hr}}\right]}{\left[\frac{\text{bkW}}{\text{bhp}}\right]\,[\text{-}]} \tag{4.16}$$

where e_{GS} = energy consumption of generator set [Btu/kWh]; η_G = efficiency of the electricity generator (not including driver) [-]; and e_D = driver energy consumption [Btu/bhp-hr]. The appropriate driver is determined by the required size based on the electricity generation capacity as calculated in eq. (4.15).

Once the onsite electricity generation, $E_{el,gen}$, and the energy consumption of the electricity generator, e_{GS}, are calculated the total energy consumption of onsite electricity generation is calculated as:

$$E_{EG} = E_{el,gen} \cdot 0.000293 \cdot e_{GS} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] = \left[\frac{\text{MMBtu}}{\text{d}}\right]\left[\frac{\text{kWh}}{\text{Btu}}\right]\left[\frac{\text{Btu}}{\text{kWh}}\right] \tag{4.17}$$

where E_{EG} = energy consumption of onsite electricity generation [MMBtu/d].

In addition to calculating the energy consumption of onsite electricity generation, this worksheet determines the grid electricity mix and the allocation method of credits from electricity export (see Section 4.5 on the *'Fuel Cycle'*

worksheet). The user is allowed to choose between two allocation methods for credit from electricity export: (i) allocation by substitution of grid electricity, and (ii) allocation by substitution of natural-gas-based electricity. The default allocation method is the substitution of natural-gas-based electricity. This method prevents achieving unreasonably large credits from operations with significant power generation.

Table 4.5: Types and size ranges of the drivers embedded in OPGEE.

Type	Fuel	Size range [bhp]
Internal combustion engine	Natural gas	95 - 2,744
Internal combustion engine	Diesel	1590 - 20,500
Simple turbine	Natural gas	384 - 2,792
Motor	Electricity	1.47 - 804

4.4 Drivers

Drivers (also known as prime movers) of pumps, compressors, and onsite electricity generators come in different types and sizes. Drivers in OPGEE include natural gas driven engines, natural gas turbines, diesel engines, and electric motors. The size and energy consumption of the driver is required to convert power requirements (e.g., downhole pump brake horsepower) into energy consumption as explained in Section 3.3.2.10. A database of drivers specifications of different types and sizes is included in OPGEE. Table 4.5 shows the types and size ranges of the drivers included in OPGEE.

The specifications of natural gas driven engines and diesel driven engines are taken from Caterpillar technical worksheets [89]. The specifications of natural gas turbines are taken from Solar Turbines technical worksheets, a subsidiary of Caterpillar [134]. The specifications of electric motors are taken from General Electric technical worksheets [90]. Data were reported in different forms and with different levels of completeness.

The data for each driver model was converted into [bhp] for power and [Btu/bhp-hr] for energy consumption. In some cases the data on engine power was given in [bhp] and energy consumption is given in [Btu/bhp-hr], so no conversion is required. In other cases only data on the electricity generator set is given. The generator set includes an engine and an electricity generator. The brake horsepower of the engine is calculated from the electric power of the generator set as:

$$P_D = \frac{P_{GS}}{\eta_G} \cdot 1.34 \qquad [\text{bhp}] = \frac{[\text{ekW}]}{[\text{-}]} \left[\frac{\text{bhp}}{\text{bkW}}\right] \tag{4.18}$$

where P_D = driver brake horsepower [bhp]; P_{GS} = electric power of the electricity generator set [ekW]; and η_G = efficiency of the electricity generator (not including engine) [-]. For the calculation of the electric power [ekW] of the electricity generator sets Caterpillar assume an electricity generator (without engine) of efficiency 96% [135, p. 4]. Accordingly η_G in eq. (4.18) is equal to 0.96 [-].

In the case where the overall efficiency of the electricity generator set is given, but the energy consumption of the engine component is not, the latter

is calculated as:

$$e_D = \frac{3.6}{\eta_{GS}}\eta_G \qquad \left[\frac{\text{MJ}}{\text{bkW-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]}{[\text{-}]}[\text{-}]$$

$$e_D = \frac{e_D \cdot 947.8}{1.34} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]\left[\frac{\text{Btu}}{\text{MJ}}\right]}{\left[\frac{\text{bhp}}{\text{bkW}}\right]} \tag{4.19}$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_{GS} = efficiency of generator set (engine + generator) [-]; η_G = efficiency of generator (without engine) [-].

The diesel engines energy consumption is reported in the technical worksheets in the form of gallons per hour [gal/hr]. This is converted into [Btu/bhp-hr] by:

$$e_D = \frac{e_D \cdot 137,380}{P_D} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{gal}}{\text{hr}}\right]\left[\frac{\text{Btu}}{\text{gal}}\right]}{[\text{bhp}]} \tag{4.20}$$

where e_D = driver energy consumption [Btu/bhp-hr]; P_D = driver brake horsepower [bhp]. The driver brake horsepower, P_D , is calculated from the electric power [ekW] of the given generator set as shown in eq. (4.18).

The calculation used to convert the efficiency of electric motors from the General Motors technical worksheets into energy consumption in [Btu/bhp-hr] is very similar to the calculation of the energy consumption of the engine component from the overall efficiency of the generator set in eq. (4.19):

$$e_D = \frac{3.6}{\eta_M} \qquad \left[\frac{\text{MJ}}{\text{kWh}}\right] = \frac{\left[\frac{\text{MJ}}{\text{kWh}}\right]}{[\text{-}]} \tag{4.21}$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_M = electric motor efficiency [-]. The energy consumption is converted to [Btu/bhp-hr] as shown in eq. (4.19).

As mentioned before in Section 3.3.2.10 OPGEE retrieves the energy consumption of the appropriate driver based on the user input and the required size.

Table 4.6: Default inputs for drivers calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
e_D	Driver energy consumption	(4.19)	-	-	[Btu/bhp-hr]		a
η_M	Electric motor efficiency	-	var.	0.84-0.96	[-]	[90]	b
$\eta_G S$	Efficiency of electricity generator set	-	var.	0.36-0.40	[-]	[89]	c
η_G	Efficiency of electricity generator (no engine)	-	0.96	-	[-]	[135, p. 4]	d
P_D	Driver brakehorse power	(4.18)	-	-	[bhp]		
P_{GS}	Electric power of elect. gen. set	-	var.	275-2000	[ekWh]	[89]	e

[a] The cited equation is for gas drivers. Energy consumption of diesel and electricity drivers is calculated in eq. (4.20) and (4.21), respectively.
[b] Motor efficiency ranges from 0.84 to 0.96 for commonly applied motor size ranges [90].
[c] Literature range cited only for gas generator sets with gas engine sizes ranging from 1535-2744 [bhp].
[d] Standard electicity generator efficiency [135, p. 4].
[e] Literature range cited for diesel generator sets [89].

4.5 Fuel cycle

For fuels consumed in OPGEE, the upstream or "fuel cycle" energy consumption and GHG emissions are required to calculate the indirect energy consumption and GHG emissions of imported fuel. For example, if purchased electricity is used on site, the emissions associated with generating and transporting that purchased electricity must be accounted for and added to the direct emissions burden. Similarly, any co-products that are sold separately from the produced oil (e.g., natural gas, electricity, NGL) must be assigned a co-production credit for emissions avoided from the system that they displace. The approach here can therefore be described as a co-product emissions assessment via system boundary expansion rather than via allocation between products [136, 137]. In all cases, the energy consumption and GHG emissions of the displaced production system is calculated from CA-GREET [74].

For the calculation of credit from the export of natural gas or natural gas liquid (NGL), the natural gas production system is displaced. For NGL export, the natural gas production system is displaced because NGL is a byproduct of gas production and does not have an independent fuel cycle. Credit is not given for avoided gas transport emissions, because it is assumed that the gas will be transported to a remote consumer.

For the calculation of credit from electricity exports, the boundary of the system is extended to the user "plug": the displaced system includes electricity generation and transport to the end user. This choice was made because exported electricity will naturally flow to the nearest consuming entity and not require long-distance transport. OPGEE calculates the energy consumption and GHG emissions of electricity generation based on the grid electricity mix (entered in the *'Electricity'* worksheet) using CA-GREET data of different electricity sources (natural gas, biomass, etc).

Table 4.7: Combustion technologies and fuels included in OPGEE.

	Natural gas	Diesel	Crude	Residual oil	Pet. coke	Coal
Industrial boiler	✓	✓	✓	✓	✓	✓
Turbine	✓	✓				
CC gas turbine	✓					
Reciprocating engine	✓	✓				

4.6 Emissions factors

Emissions factors are required for the calculation of GHG emissions from combustion (fuel combustion) and non-combustion (venting and fugitives) sources.

4.6.1 Combustion emissions factors

The emissions factors for fuel combustion are from CA-GREET [74]. Table 4.7 shows the technologies and fuels included. Gas species tracked include VOC, CO, CH_4, N_2O, and CO_2. Emissions are converted into carbon dioxide equivalent using IPCC GWPs [138] as shown in eq. (4.22).

$$EM_{CO_2eq,i} = EM_i \cdot \mathrm{GWP}_i \qquad [\mathrm{gCO_2eq}] \tag{4.22}$$

where $EM_{CO_2eq,i}$ = emissions of species i in carbon dioxide equivalent [gCO_2eq]; EM_i = emissions of species i [g]; and GWP_i = GWP of species i [$gCO_2eq./g$]. GWPs are discussed in Section 6.1.

4.6.2 Non-combustion emissions factors

Section 4.7 describes how emissions factors for venting and some fugitives sources are generated from the ARB survey data [100]. Emissions factors from ARB are specified by gas component. The ARB survey data used to generate emissions factors for venting are shown in Table 4.8.

The emissions factors for venting by gas component were calculated using ARB survey data as:

$$\begin{aligned} EF_{CO_2Vent} &= \frac{a_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \\ EF_{CH_4Vent} &= \frac{b_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \end{aligned} \tag{4.23}$$

where EF_{CO_2Vent} = emissions factor of CO_2 venting [g/event; g/mile-yr; g/MMscf]. For a description of a_{EF_V}, b_{EF_V}, and c_{EF_V} parameters see Table 4.8.

Table 4.8: ARB data used in the calculation of venting emissions factors (unit specified below) [100].

Source	Total CO_2 emissions (tonne/yr) a_{EF_V}	Total CH_4 emissions (tonne/yr) b_{EF_V}	# units (event/yr, otherwise noted) c_{EF_V}
Well workovers			
- Ultra-heavy	0	0	–
- Heavy	405	1,428	12,889
- Light	225	575	5,424
- Ultra-light	9	65	599
Well cleanups			
- Ultra-heavy	0	0	–
- Heavy	103	90	956
- Light	113	201	1977
- Ultra-light	3	21	187
Compressor startups	4	69	1071
Compressor blowdowns	172	3,238	1071
Gathering pipelines maintenance	2659	2490	2295 (mile)
Gathering pipelines pigging	104	5	1417
Gas dehydrator[a]	308	10829	701123.3 (MMscf/yr)

[a] Emissions factors of venting from gas dehydrator are calculated on volume throughput basis.

Table 4.9: ARB data used in the calculation of fugitives emissions factors (unit specified below).

Source	Total CO_2 emissions (tonne/yr) a_{EF_F}	Total CH_4 emissions (tonne/yr) b_{EF_F}	# units (event/yr, otherwise noted) c_{EF_F}
Active wells			
- Ultra-heavy	0	0	–
- Heavy	66	155	36,619
- Light	459	1,415	14,261
- Ultra-light	19	139	1,323
Well cellars			
- Ultra-heavy	–	3	22
- Heavy	–	933	7,461
- Light	–	850	4,998
- Ultra-light	–	369	2,168
Gathering pipelines	327	867	2,295 (mile)
Separators	11	170	4,618
Sumps and pits	–	264	250
Gas dehydrator[a]	16,682	10,802	701123.3 (MMscf/yr)

[a] Emissions factors of fugitives from gas dehydrator are calculated on volume basis.

Table 4.10: An example of EPA emissions factors for oil and gas production components (g/unit-yr).

Source	CH_4	VOC emissions
Non-leaking components (< 10,000 ppmv)		
Valves		
Gas service	148	37
Heavy oil service	69	2
Light oil service	101	49
Connectors		
Gas service	60	15
Heavy oil service	62	2
Light oil service	52	25
Leaking components (> 10,000 ppmv)		
Valves		
Gas service	590,678	147,025
Heavy oil service	–	–
Light oil service	465,479	225,134
Connectors		
Gas service	159,029	39,584
Heavy oil service	–	–
Light oil service	141,668	68,519

Similar calculations were performed for emissions factors for fugitives from the sources listed in Table 4.9. Emissions factors for fugitives from other sources (valves, flanges, etc) are taken from API [27, p. 20].

Emissions factors for gas dehydrators and AGR units are calculated on volume basis (i.e., in grams per MMscf processed gas). The emissions factors for venting and fugitives from the gas dehydrator are calculated as shown in Tables 4.8 and 4.9. As mentioned in Section 3.4.2.3, venting from the AGR unit is calculated from the gas balance of OPGEE by assuming that all CO_2 left in the gas stream after flaring, fugitives, and other venting is vented. The emissions factor for CH_4 fugitives from the AGR unit is 965 scf CH_4/MMscf of gas throughput [139, p. 23].

EPA emissions factors for fugitives from the components listed in Table 4.15 are reported by API as total hydrocarbons (THC) by service type, i.e. gas service, heavy oil service [27, p. 20]. As explained in Section 4.7.3.1 the THC emissions factors are calculated assuming that 25% of the components are associated with gas service and the remaining 75% are associated with oil service. An example of EPA emissions factors for oil and gas production components after speciation is shown in Table 4.10 for valves and connectors [27, p. 20]. Fugitives from non-leaking components are negligible. The user determines the percentage of leaking components in the *'Venting & Fugitives'* worksheet.

Emissions factors for land use change are discussed in Section 3.2. Table 3.2 shows the emissions factors per unit of crude oil produced for low, medium, and high intensity development in low, medium, and high ecosystem produc-

tivity environments [75].

4.7 Venting and fugitive emissions

4.7.1 Introduction to venting, and fugitive emissions

Venting and fugitive emissions can be a significant source of GHG emissions from oil production operations. We use these definitions here:

Venting emissions Purposeful release of non-combusted hydrocarbon gases to the atmosphere. Venting emissions generally occur during maintenance operations and other intermittent, infrequent activities.

Fugitive emissions Non-purposeful or non-planned emissions of non-combusted hydrocarbon gases to the atmosphere. Fugitive emissions commonly result from leaking equipment and tanks.

Venting and fugitive emissions arise from oil field operations and devices. Sources include well workovers and cleanups, compressor startups and blowdowns, pipeline maintenance, gas dehydrators, AGR units, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). The heterogenous nature of these sources makes venting and fugitive sources difficult to monitor and track.

4.7.2 Calculation of venting emissions

Two types of venting occur in production and processing facilities: (i) operational venting, and (ii) venting to dispose of associated gas where there is no infrastructure for the use of gas. Operational venting is associated with production, processing and maintenance operations such as well workovers and cleanups, compressor blowdowns, and gas processing units (AGR and glycol dehydrator). These operations necessitate the venting of some gas. For instance, in a glycol dehydrator, steam generated in the reboiler strips water from the liquid glycol as it rises up the packed bed and the water vapor and desorbed natural gas are vented from the top of the stripper [47, p. 140].

Venting associated with production and surface operations is estimated using data collected in the 2007 oil & gas GHG emissions survey in California, performed by California Air Resources Board (ARB) [100], and the API manual of petroleum measurement standards [66].

4.7.2.1 Venting of associated gas as disposal mechanism (flaring substitute)

Venting to dispose of large quantities of gas is not common, due to safety concerns and environmental impacts. However, it may be practiced in some fields as an alternative to flaring (e.g., local regulations may prohibit flaring). Venting as an alternative to flaring is not environmentally acceptable because methane and volatile organic compounds (VOCs) have higher GWPs compared to carbon dioxide. The venting of produced gas is a user input and is presented by the venting-to-oil ratio or VOR in the *'User Inputs & Results'*

Table 4.11: Emissions data used in the estimation of operational venting. Data from California oil fields, 2007 [100].

Source	Activity a_{V_G}	Unit	Oil Prod. (bbl/yr) b_{V_G}	Activity factor c_{V_G}	Unit [event/bbl]
Well workovers					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	12,889	[event/yr]	156,304,520	8.25×10^{-5}	[event/bbl]
- Light	5,424	[event/yr]	61,524,698	8.82×10^{-5}	[event/bbl]
- Ultra-light	599	[event/yr]	15,649,398	3.83×10^{-5}	[event/bbl]
Well cleanups					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	956	[event/yr]	156,304,520	6.12×10^{-6}	[event/bbl]
- Light	1977	[event/yr]	61,524,698	3.21×10^{-5}	[event/bbl]
- Ultra-light	187	[event/yr]	15,649,398	1.19×10^{-5}	[event/bbl]
Compressors	$\simeq$643[a]	[device]	234,093,299	2.75×10^{-6}	[unit-yr/bbl]
Gathering pipelines	1218[b]	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Pigging launcher openings	$\simeq$850[a]	[event/yr]	234,093,299	3.63×10^{-6}	[event/bbl]

a - Estimated from the total number of compressors which is shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes ≈60% of the total number of wells [100]. Accordingly the crude oil business is roughly allocated 60% of the total number of compressors reported in the survey.
b - Estimated by summing the number of miles associated with the crude oil business. Miles associated with dry gas production and gas storage facilities are not counted. For central gas processing facilities 75% of the miles are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where ≈75% of the produced gas is associated gas [100].

worksheet. This quantity is used to compute associated gas disposal venting emissions. The calculation of emissions from vented gas is as shown in eq. (4.33).

Venting & Fugitives 2.1.1

4.7.2.2 *Venting from general sources*

Operational venting may be associated with units (e.g., compressors), events (e.g., well workovers), or distance of product transport (e.g., gathering pipelines). The amount of gas vented from various sources is calculated using the number of unit-years, mile-years, or events associated with the volume of oil produced. A unit-year (abbreviated unit-yr), for example, is one unit operating over a time period of one year.

The sources for general venting are listed in Table 4.11. The first step in calculating venting emissions from general sources is to estimate the number of unit-years, mile-years, or events associated with one barrel of oil, as shown in Table 4.11. The venting emissions from general sources are calculated as:

Venting & Fugitives 2.1.2

$$EM_{V_G} = \sum_s c_{V_G,s} Q_o EF_{V_s} \qquad [\text{g/d}] \tag{4.24}$$

where EM_{V_G} = venting emissions from general sources as listed in Table 4.11 [g/d]; $c_{V_G,s}$ = activity factor per unit of oil produced [unit-years/bbl, event/bbl or mile-years/bbl]; Q_o = total rate of oil production [bbl/d]; and EF_{V_s} = vent emissions factors for source s [g/unit-yr, g/mile-yr, or g/event]. $c_{V_G,s}$ is calculated as shown in Table 4.11 by multiplying $a_{V_G,s}$ which is the total number of units, events or miles surveyed [mile, unit, or event/yr] with $b_{V_G,s}$ which is the reported oil production volumes [bbl/yr].

The emissions factors and therefore the emissions estimates are specific to gas components (e.g., CO_2). The emissions factors for the venting of CO_2 and CH_4 are also estimated using data from the ARB survey [100]. Calculations of emissions factors are explained in Section 4.6.

4.7.2.3 *Venting from gas processing units*

Other than the general venting emissions sources that are listed in Table 4.11 there are major venting sources which include venting from gas processing tecnologies like glycol dehydrators and amine acid gas removal (AGR) systems The methods for calculating venting from glycol dehydration and amine AGR units are volume based. For the glycol dehydrator unit the venting emissions of both CO_2 and CH_4 are calculated based on the gas unit volume as:

Venting & Fugitives 2.1.2

$$EM_{V_{GD}} = Q_{GD} EF_{V_{GD}} \qquad [\text{g/d}] \tag{4.25}$$

where $\text{EM}_{V_{GD}}$ = venting emissions from the glycol dehydrator unit [g/d]; Q_{GD} = volume throughput of the glycol dehydrator unit [MMscf/d]; and $EF_{V_{GD}}$ = vent emissions factors for glycol dehydrator [g/MMscf]. The emissions factors as noted above are calculated from the ARB survey data [100] as explained above. The approximate volume throughput of the glycol dehydrator is determined by the gas balance and is calculated as shown in eq. (3.33). A description of the gas balance is found in Section 4.1.

The calculation of CH_4 venting from the AGR unit is performed as outlined above for the glycol dehydrator:

Venting & Fugitives 2.1.3

$$EM_{V_{AGR}} = Q_{AGR} EF_{V_{AGR}} \qquad [\text{g/d}] \tag{4.26}$$

where $EM_{V_{AGR}}$ = CH_4 venting emissions from the amine AGR unit [g/d]; Q_{AGR} = volume of the amine AGR unit [MMscf/d]; and $EF_{V_{AGR}}$ = vent emissions factor for AGR unit [gCH_4/MMscf]. On the other hand, the calculation of the CO_2 emissions from the amine AGR unit is determined by the gas balance where all the CO_2 left in the gas after flaring, fugitives and other venting is assumed to be absorbed and stripped in the amine treater.

Table 4.12: Average working and standing loss gas speciation profile.

Species	Mol%
CH_4	22.36
C_2H_6	20.49
C_3H_8	28.00
i-C_4H_{10}	6.84
n-C_4H_{10}	10.92
C5+	11.40

4.7.2.4 *Venting from crude oil storage tanks*

The estimation of venting emissions from storage tanks is based on an emissions factor generated using data from the ARB survey. The emissions factor for CH_4 emissions was calculated as 49.2 gCH_4/bbl oil [100]. From the CH_4 emissions factor an emissions factor for VOCs was calculated given the average speciation profile of storage tank losses as shown in Table 4.12 [64, p. ES-2]. VOCs are mainly composed of C_2 to C_4 species which on average constitute 66.24% of the total storage tank losses. Accordingly the VOCs emissions factor was calculated as 145.75 gVOC/bbl oil.

Venting & Fugitives 3.1.3 Emissions Factors Table 1.2

4.7.2.5 *Venting emissions gathering*

All the methods that have been discussed for the estimation of emissions from venting generate weight of gas species lost into the atmosphere (the balancing of the gas as is discussed in Section 4.1). Therefore weight is converted to volume using the densities of gas species (e.g., CH_4) [113]. The estimated weight of the gas species emissions is converted to [g/d] and divided by the species density [g/ft^3].

Venting & Fugitives 2.1.2 Input Data Table 1.2

After the weight and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate venting emissions to the different stages in OPGEE (e.g., *'Production & Extraction'*). Table 4.13 lists the sources of venting emissions under each process stage. Crude oil transport is not included because it is a separate process.

The emissions volumes from each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs of the gas constituents [138].

4.7.3 Calculation of fugitive emissions

The estimation of fugitive emissions from various components is difficult due to the non-planned nature of the losses and the number of sources. This includes fugitive emissions from active wells, well cellars, gas processing units, gathering pipelines, sumps and pits, storage tanks (e.g., free knock out vessel) and various equipment (valves, connectors, flanges, etc). Fugitives associated with production and surface operations are estimated using data collected by

Table 4.13: Categorization of venting emissions sources by process stage.

Process stage	Venting emissions sources
Exploration	None
Drilling & development	None
Production & extraction	None
Oil field processing	Flaring substitute[a]
	Gas dehydrator
	AGR unit
	Storage standing losses[b]
	Storage working losses [b]
Maintenance	Well workovers and cleanups
	Gathering pipelines maintenance and pigging
	Compressor blowdowns and startups
Waste disposal	None

a - Venting of associated gas as a flaring substitute is computed in *'Venting & Fugitives 2.1'*.
b - Standing and working losses are combined into a single emissions factor in *'Emissions Factors'* Table 1.2

ARB [100], and emissions factors from the API workbook for oil and gas production equipment fugitive emissions [27].

The approach used to estimate fugitive emissions is similar to the approach used in the calculation of venting emissions. Fugitive losses are linked to various units (e.g., equipment and active wells), gathering pipeline miles, and volumes of gas processing units (e.g., AGR unit). Most fugitive losses are linked to units and equipment. The number of unit-years or mile-years associated with the total volume of oil produced is estimated using the ARB survey data [100].

Venting & Fugitives 2.2.1

4.7.3.1 Fugitives from general sources

Fugitive emissions from general sources are listed in Table 4.14. This table does not include all equipment fugitives. API research suggests that a good approximation of the number of components can be obtained by estimating the number of valves and pumps and then calculating the probable number of flanges, connectors, open-ended lines, and other components from the number of valves [27, p. 14]. During a field study of petroleum production operations, API found that the number of flanges is usually about the same as the number of valves, while the number of connectors (threaded pipes and tubing fittings) is about three times the number of valves. API also found that about 10% of all valves have one side that can be opened to the atmosphere (open-ended lines) and that the number of other components is approximately 5% of the number of valves. No correlation was found between the number of valves and the number of pumps [27, p. 14]. The number of valves and pump seals are estimated from the ARB survey data as shown in Table 4.14 and the number of remaining components is estimated from the number of valves using the API

Table 4.14: Data used in the estimation of fugitives. Source: ARB (2011).

Source	Activity a_{F_G}	Unit	Oil prod. (bbl/yr) b_{F_G}	Activity factor c_{F_G}	Unit
Gathering pipelines[a]	1218	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Separators	$\simeq$3557[b]	[unit]	234,093,299	1.52×10^{-5}	[unit-yr/bbl]
Sumps & pits	250	[unit]	234,093,299	1.07×10^{-6}	[unit-yr/bbl]
Valves (without open-ends)	$\simeq$2,647,951[c]	[unit]	234,093,299	1.13×10^{-2}	[unit-yr/bbl]
Pump seals	$\simeq$48,444[c]	[unit]	234,093,299	2.07×10^{-4}	[unit-yr/bbl]

a - Miles of pipeline. See Table 4.11.
b - Estimated by summing the number of separators associated with the crude oil business. Separators associated with dry gas production and gas storage facilities are not counted. For gas processing facilities, 75% of the separators are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where $\approx$75% of the produced gas is associated gas [100].
c - Estimated by summing the number of valves associated with crude oil service. Valves associated with natural gas service are shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes $\approx$60% of the total number of wells [100]. Accordingly the crude oil business is roughly allocated 60% of the valves associated with natural gas service.

Table 4.15: Estimating the number of remaining components.

Component	Number
Valves (with open ends)	N
Pumps	No correlation
Flanges	N
Connectors	$3N$
Open-ends	$0.1N$
Others[a]	$0.05N$

a - Includes compressor seals, diaphragms, drains, etc.

method.

As shown in Table 4.14 the number of unit-years or mile-years associated with one barrel of oil production is estimated using data from the ARB survey [100]. The number of remaining sources of fugitive emissions is estimated from the number of valves as outlined in Table 4.15. Therefore the total number of unit-years or mile-years associated with the amount of oil produced in OPGEE and the fugitive emissions from the various sources listed in Tables 4.14 and 4.15 is calculated as:

Venting & Fugitives 1.2 2.2.1

$$EM_{F_G} = \sum_s c_{F_G,s} Q_o EF_{F_s} \qquad [\text{g/d}] \tag{4.27}$$

where EM_{F_G} = fugitive emissions [g/d]; $c_{F_G,s}$ = number of unit-years or mile-years per barrel of oil and is calculated as shown in Table 4.14; Q_o = total rate of oil production entered by the user [bbl/d]; and EF_{F_s} = fugitive emissions factors for source s [g/unit-yr, g/mile-yr]. $c_{F_G,s}$ is calculated by multiplying $a_{F_G,s}$ which is the total number of units or miles surveyed [mile, unit] with $b_{F_G,s}$ which is the reported oil production volumes [bbl/yr]. For the estimation of fugitives from active wells and well cellars, the number of active wells (producing wells) is given in the *'User Inputs & Results'* worksheet and the number of well cellars is assumed equal to the number of active wells.

The emissions factors generated from the ARB survey, and therefore the calculated emissions, are specific to gas components (e.g., CO_2). The calculation of the emissions factors is explained in Section 4.6. Emissions factors for equipment fugitives that are listed in Table 4.15 are taken from the API documentation [27, p. 20]. The emissions factors from API are not speciated. The speciation in Table 4.16 is used to allocate the total hydrocarbon (THC) emissions calculated using the API emissions factors to the main gas components, i.e. methane and VOC [27, p. 15].

As shown in Table 4.16, the fractions are different for fugitives from different streams. For the division of THC emissions, 75% of the components are assumed in oil service, and 25% in gas service. This assumption is based on an example from the API methods on the calculation of fugitive emissions from a crude oil production operations which co-produce natural gas [27, p. 16]. For oil service components the fraction is determined by the API gravity of the

Table 4.16: Speciation fractions for total hydrocarbon (THC) emissions calculated using API emissions factors [%].

Emissions component	Gas	Heavy oil	Light oil
Methane	0.687	0.942	0.612
VOC	0.171	0.030	0.296

oil. For the calculation of the volume of VOC emissions the VOC is broken down into 31% C_2, 42% C_3, and 27% C_4. The fraction of C_5+ VOC components is negligible. This breakdown is based on average THC emissions speciation profiles [64, p. ES-2].

4.7.3.2 *Fugitives from gas processing units*

Other than the general fugitive emissions sources that are listed in Tables 4.14 and 4.15, fugitives sources include gas processing units like glycol dehydrator units and amine acid gas removal (AGR) units. The methods for calculating fugitives from glycol dehydration and amine AGR units are volume based. The fugitive emissions of both CO_2 and CH_4 are calculated based on the gas unit throughput volume as:

Venting & Fugitives 1.2 2.2.1

$$EM_{F_{GP}} = Q_{GP} EF_{F_{GP}} \qquad [\mathrm{g/d}] \tag{4.28}$$

where $EM_{F_{GP}}$ = fugitive emissions from the gas processing unit [g/d]; Q_{GP} = volume throughput of the gas processing unit [MMscf/d]; and $EF_{F_{GP}}$ = fugitive emissions factors for gas processing unit [g/MMscf]. The emissions factors are calculated from the ARB survey data [100] as explained in Section 4.6.2. The emissions factor for fugitive CH_4 emissions from AGR unit is taken from [139, p. 23]. The approximate volume of the gas processing unit is determined by the gas balance and is calculated as shown in eq. (3.33). A description of the gas balance is found in Section 4.1.

4.7.3.3 *Fugitive emissions gathering*

All the methods that have been discussed for the estimation of fugitives end up generating mass of gas species lost into the atmosphere. The balancing of the gas is discussed in Section 4.1. Therefore mass is converted to volume using the densities of gas species [113]. After the mass and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate fugitive emissions to the different stages in OPGEE (e.g., *'Production & Extraction'*). Table 4.17 lists the sources of fugitive emissions under each process stage. Fugitive emissions from crude oil transport are not included because it forms a separate process.

Venting & Fugitives 2.2.1

The emissions volumes of each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs [138].

Table 4.17: Categorization of fugitive emissions sources by process stage.

Process stage	Fugitive emissions sources
Exploration	None
Drilling and development	None
Production and extraction	Active wells
	Well cellars
Oil field processing	Separators
	Gas dehydrator
	AGR unit
	Gathering pipelines
	Sumps and pits
	Components (valves, connectors, flanges, etc)
Maintenance	None
Waste disposal	None

4.7.4 Default values for venting and fugitive emissions

The default emissions factors and the number of associated unit-years, mile-years or events/yr are generated from the ARB survey data [100]. The estimation of the number of unit-years, mile-years or events/yr was previously discussed. The user is allowed to overwrite these defaults. As these defaults represent the average case in California, in some cases they might not be a good representation of the level of venting and fugitives in other areas of the world. This is particularly true where practices and environmental regulations are significantly different than California regulations. The average EPA emissions factors for fugitives from the various components listed in Table 4.15 are used as default [27, p. 20]. These defaults represent the average US case and can also be overwritten by the user to represent changes in equipment condition, practices, and environmental regulations.

Table 4.18: Default inputs for venting, flaring, and fugitive emissions.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$c_{F_G,s}$	Number of fugitive source per oil barrel	-	Table 4.14	-	[unit-yr/bbl]	[100]	a
$c_{V_G,s}$	Number of vent source per oil barrel	-	Table 4.11	-	[event/bbl]	[100]	b
$EF_{F_{GP}}$	Fugitive em. factors for gas proc. unit	-	Section 4.6	-	[g/MMscf]	[100, 139]	
EF_{F_s}	Fugitive emissions factors for source s	-	Tables 4.9 & 4.10	-	[g/unit-yr]	[27, 100]	c
$EF_{V_{AGR}}$	Vent emissions factors for AGR	-	0	-	[gCH_4/MMscf]	[100]	d
$EF_{V_{GD}}$	Vent emissions factors for gas dehydrator	-	Section 4.6	-	[g/MMscf]	[100]	
EF_{V_s}	Vent emissions factors for source s	-	Table 4.8		[g/event]	[100]	e
EM_{F_G}	Fugitive emissions general	(4.27)	-	-	[g/d]		
$EM_{F_{GP}}$	Fugitive emissions from gas proc. unit	(4.28)	-	-	[g/d]		
$EM_{V_{AGR}}$	Vent emissions from AGR	(4.26)	-	-	[g/d]		
$EM_{V_{GD}}$	Vent emissions from gas dehydrator	(4.25)	-	-	[g/d]		
EM_{V_G}	Vent emissions general	(4.24)	-	-	[g/d]		
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1	-	[gCO_2eq./g]	[138]	f
Π_i	Stoichiometric combustion ratios	-	Table 4.20	-	[gCO_2/g]	-	g
Q_{AGR}	Volume of amine treater	-	*'Gas Balance'*	-	[MMscf/d]		
Q_{GD}	Volume of gas dehydrator	-	*'Gas Balance'*	-	[MMscf/d]		
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{GP}	Volume of gas processing unit	-	*'Gas Balance'*	-	[MMscf/d]		
ρ_i	Gas density for species i	-	*'Input Data'* Table 2.2	-	[g/ft^3]	-	h
x_i	Mole fraction of gas composition	-	*'Gas Balance'* Table 1.1	-	[-]	[100]	i

a - Most of the fugitives are associated with units. Therefore the most common unit for the number of sources per oil barrel is [unit-yr/bbl]. Other units include [mile-yr/bbl] for fugitives associated with pipeline miles.
b - Most venting is associated with events. Therefore the most common unit for number of sources per oil barrel is [event/bbl]. Other units include [unit-yr/bbl] and [mile-yr/bbl] for venting associated with units and pipeline miles, respectively.

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes

c - Most of the fugitives are associated with units. Therefore the most common unit for fugitive emissions factors is [q/unit-yr]. Other units include [g/mile-yr] for fugitives associated with pipeline miles.
d - Venting of CO_2 from the AGR unit is calculated from the gas balance.
e - Most of the venting is associated with events. Therefore the most common unit for vent emissions factors is [g/event]. Other units include [q/unit-yr] and [g/mile-yr] for venting associated with units and pipeline miles, respectively.
f - 100-year GWPs from the IPCC Fourth Assessment Report [138].
g - Standard combustion stoichiometry assuming complete combustion.
h - Standard gas densities [113]
i - Gas composition can vary. Default gas composition given from [100].

4.8 Flaring

Flaring is used to dispose of associated natural gas where there is no economic use for the gas. Associated gas evolves from crude oil as it is brought to surface temperatures and pressures, and is separated from oil before transport (see Section 3.4). Gas flaring resulted in emissions of 0.28 Gt CO_2 eq. in 2008, or about 1% of global GHG emissions [13]. Because gas flaring is used to dispose of gas (typically at remote locations), the volume of flared gas is uncertain.

The NOAA National Geophysical Data Center have used earth observation satellite data for the estimation of gas flaring volumes since 1994 [13]. Global gas flaring volumes are estimated for individual countries. Results show that gas flaring is concentrated in a small number of countries: in 2008, Russia and Nigeria together accounted for 40% of global gas flaring [13].

4.8.1 Calculation of flaring emissions

For the calculation of flaring emissions, the key input parameter is the flaring-to-oil ratio, or FOR [scf/bbl]. The FOR is converted into flaring volume using the volume of oil produced:

Flaring 1.3

$$Q_F = \frac{FOR \cdot Q_o}{10^6} \quad \text{[MMscf/d]} \tag{4.29}$$

where Q_F = flaring volume [MMscf/d]; FOR = flaring-to-oil ratio [scf/bbl of oil]; and Q_o = volume of oil produced [bbl/d].

The OPGEE default FOR is given by country-level flaring data [140] and production volume [141] for 2010 and 2011. The default flaring rate is retrieved from the *'Flaring'* worksheet based on the field location specified in the *'User Inputs & Results'* worksheet. The flaring rate in a specific oil field could be significantly higher or lower than the country-average. In the case no default is available for the specified field location, the world average is taken as the default value.

Flaring Table 4.1

Carbon-dioxide-equivalent flaring emissions are calculated from the flaring volume using the flare efficiency η_F. The flare efficiency is the fraction of flared gas that is combusted. The remaining gas undergoes fuel stripping and is emitted as unburned hydrocarbons.

Flaring 3.1

Flare efficiency varies with flare exit velocities and diameters, cross wind speed, and gas composition [11, 12]. For example, flare efficiencies in Alberta were estimated to range from 55% to $\geq$ 99%, with a median value of 95%, adjusted for wind speed distributions [11].

If the user does not have field specific information about the flare system design and average ambient wind conditions, then OPGEE populates the model with a default flare efficiency of 95%. If the user has the full amount of required data (see Table 4.19) then the user can determine the field-specific flaring efficiency.

Flaring 1.1

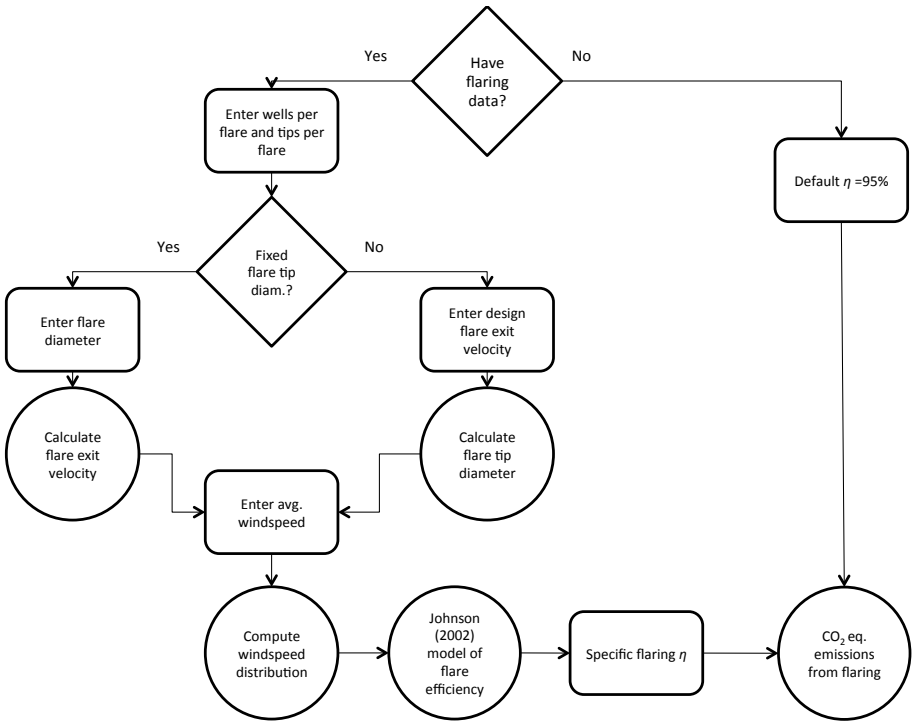

Figure 4.6: Flowchart illustrating the logic of the flaring computation worksheet.

The logical progression of the flaring worksheet is shown as a flow-chart in Figure 4.6.

OPGEE uses a flare efficiency equation developed by Johnson and Kostiuk [142]: *Flaring 3.1*

$$\eta_F = 1 - \frac{A \exp\left[\frac{BU_\infty}{(gVd)^{\frac{1}{3}}}\right]}{LHV^3} \tag{4.30}$$

Where A = 156.4 [MJ/kg], B = 0.318 [dimensionless], U_∞ is the wind velocity [m/s], g is the gravitational constant [m/s^2], V is flare gas exit velocity [m/s], d is flare pipe exit diameter [m], and LHV is the lower heating value of the flare gas [MJ/kg]. The most impactful parameters on flare efficiency are wind speed, gas exit velocity, and LHV. For completeness, all parameters are discussed below.

A second parametric model by Gogolek was explored [143], but for ease of integration into OPGEE, the Johnson model was selected.

Table 4.19: Data requirements for utilizing field-specific flaring calculation.

Data requirement	Units
Oil production	[bbl/d]
Flaring intensity	[scf/bbl]
Number of flares	[#]
Number of flare tips per flare	[#]
Flare tip diameter	[in]
Lower heating value of gas (LHV)	[MJ/kg] or [Btu/scf]
Average wind speed	[mph]

4.8.1.1 Constants

The Johnson and Kostiuk model, contains different values for A and B given for methane flares and propane flares (the two flare gasses tested in the experiments). We implement the constants for methane flares for two reasons: first, the primary gas component in most flares is methane, and second, there is no simple direct linear relationship that can be used to interpolate the A and B values when non-pure gas mixtures are flared.

4.8.1.2 Lower heating value

The flare gas LHV is calculated by multiplying the LHV for each component of the gas by that components mass fraction. The mass fraction of each gas species is taken from the *'Gas Balance'* worksheet, and the LHV for each species is taken from the *'Fuel Specs'* worksheet. If the flare gas has significant non-combustibles like N_2 and CO_2, the LHV of the gas, and thus the flare efficiency, will be reduced. *Flaring 1.4*

4.8.1.3 Flare gas exit velocity and diameter

There are cases where multiple wells feed to a single flare. There are also cases where each flare stack has multiple openings (flare tips) out of which gas exits. To calculate an efficiency, we are interested in the velocity of the gas coming out of each individual flare tip. As such, the user is asked to enter the number of wells per flare and the number of flare tips per flare. The volumetric flowrate of gas exiting through each opening is found by dividing the total flowrate for the field by the number of flare tips in the field. *Flaring 2.1.2* *Flaring 2.1.4*

Some flare tips have a variable orifice diameter, to allow for more even combustion properties under varying flow conditions. The user therefore first chooses whether they have a fixed diameter flare or a variable diameter flare. If the user chooses a variable tip diameter, then they choose a flow rate to size the flare to. Suggested maximum regulated flare exit velocity are given in the notes section of this entry. A US EPA regulatory standard is used. For onshore U.S. production, the EPA 60.18 40 CFR Ch.1 [144] regulation states that for flares with a LHV of between 200 and 1,000 btu/scf, the maximum allowable *Flaring 2.2.1*

gas exit velocity is 122 feet/sec. For flares with a LHV above 1,000 btu/scf, the maximum allowable gas exit velocity is 400 feet/sec [144].

Flaring 2.2.2.1

Users with pipe diameter information can enter that information. The flare pipe exit diameter is used directly in the Johnson and Kostiuk model, and is also used to calculate the flare gas exit velocity. Flare gas exit velocity is calculated by dividing the mass flux of gas by the cross sectional area of the pipe.

Flaring 2.2.3.2

Flaring 2.2.3.3

4.8.1.4 Volume of gas flared

If the user knows the volume of gas that is flared in their field, they can input these data. Otherwise, OPGEE estimates this number based on what country the user selected on the '*User Inputs & Results*' worksheet.

Flaring 1.3

Flaring Table 4.1

4.8.1.5 Wind Speed

The user must enter an average wind speed for their field. If the user is onshore in the United States, the user can select a local area from the dropdown list, and this will populate the wind speed cell with an average local wind speed. National Oceanic and Atmospheric Administration data on the average wind speed for hundreds of locations across the United States.

Flaring 2.3

Flaring Table 4.2

Because the efficiency of combustion (4.30) has an exponential dependence on wind speed, a seemly small increase in wind speed can have a large effect on the flare efficiency, and thus a large effect on emissions. As such, using a yearly average wind speed to calculate flaring efficiency can yield an inaccurate result. To resolve this, the Rayleigh probability distribution method has been adapted and applied from da Rossa [145]. Figure 4.7 illustrates the fit of the Rayleigh distribution to National Renewable Energy Laboratory wind data for 6 randomly chosen wind sites in the western United States.

The Rayleigh method estimates a wind velocity probability distribution based on what is known about wind speeds. In this case, the user input average (mean) wind speed. This method estimates a mode (most frequently occurring wind speed) using the relationship:

$$m_U = \frac{\mu_U}{\sqrt{\frac{\pi}{2}}} \tag{4.31}$$

where m_U is the mode of the windspeed [mph], and μ_U is the average (mean) windspeed [mph].

The probability density curve for the Rayleigh distribution is calculated from the mode using the expression:

$$p(U) = \frac{U}{m_U} \exp\left[-\frac{1}{2}\left(\frac{U^2}{m_U^2}\right)\right] \tag{4.32}$$

where $p(U)$ is the probability of finding wind speeds of velocity U [mph].

Table 4.20: Stoichiometric relationships for complete combustion.

Fuel	Stoichiometric factor Π
CO_2	1
CH_4	44/16
C_2H_6	88/30
C_3H_8	132/44
C_4H_{10}	176/58

To calculate an overall flaring efficiency, the efficiency of combustion at each wind speed along the probability density curve is calculated using (4.30), and efficiencies are summed by their fractional probability. Figure 4.8 shows the probability distribution for an average wind speed of 30 mph.

Using the Johnson and Kostiuk (2002) model with these data, OPGEE calculates the flaring combustion efficiency. *Flaring 3.1*

4.8.2 Emissions from flares

Emissions from non-combusted gas are calculated using the composition of associated gas from the *'Gas Balance'* worksheet: *Flaring 3.2.2.1*

$$EM_{F,str} = Q_F(1-\eta_F)\sum_i x_i \rho_i GWP_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.33}$$

where $EM_{F,str}$ = flaring emissions from stripped, non-combusted gas [tCO_2eq/d]; η_F = flaring efficiency [%]; Q_F = flaring volume [MMscf/d]; i = index of gas species CO_2, CH_4, and volatile organic compounds C_2H_6, C_3H_8 and C_4H_{10}; x_i = molar fraction of gas component i [mol/mol]; ρ_i = density of gas component i [g/ft^3]; and GWP_i = GWP of gas component i [g CO_2 eq. /g gas].

Emissions from flare combustion products assume complete combustion: *Flaring 3.2.1.1*

$$EM_{F,comb} = Q_F \eta_F \sum_i x_i \rho_i \Pi_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.34}$$

where $EM_{F,comb}$ = flaring emissions from combusted gas [$tCO_2eq./d$]; Π_i = stoichiometric relationship between component i and product CO_2 for complete combustion [g CO_2/g gas]. Combustion factors are listed in Table 4.20.

Total flaring emissions are the sum of stripped and combustion emissions: *Flaring 3.2*

$$EM_{F,tot} = EM_{F,str} + EM_{F,comb} \qquad [\text{tCO}_2\text{eq/d}] \tag{4.35}$$

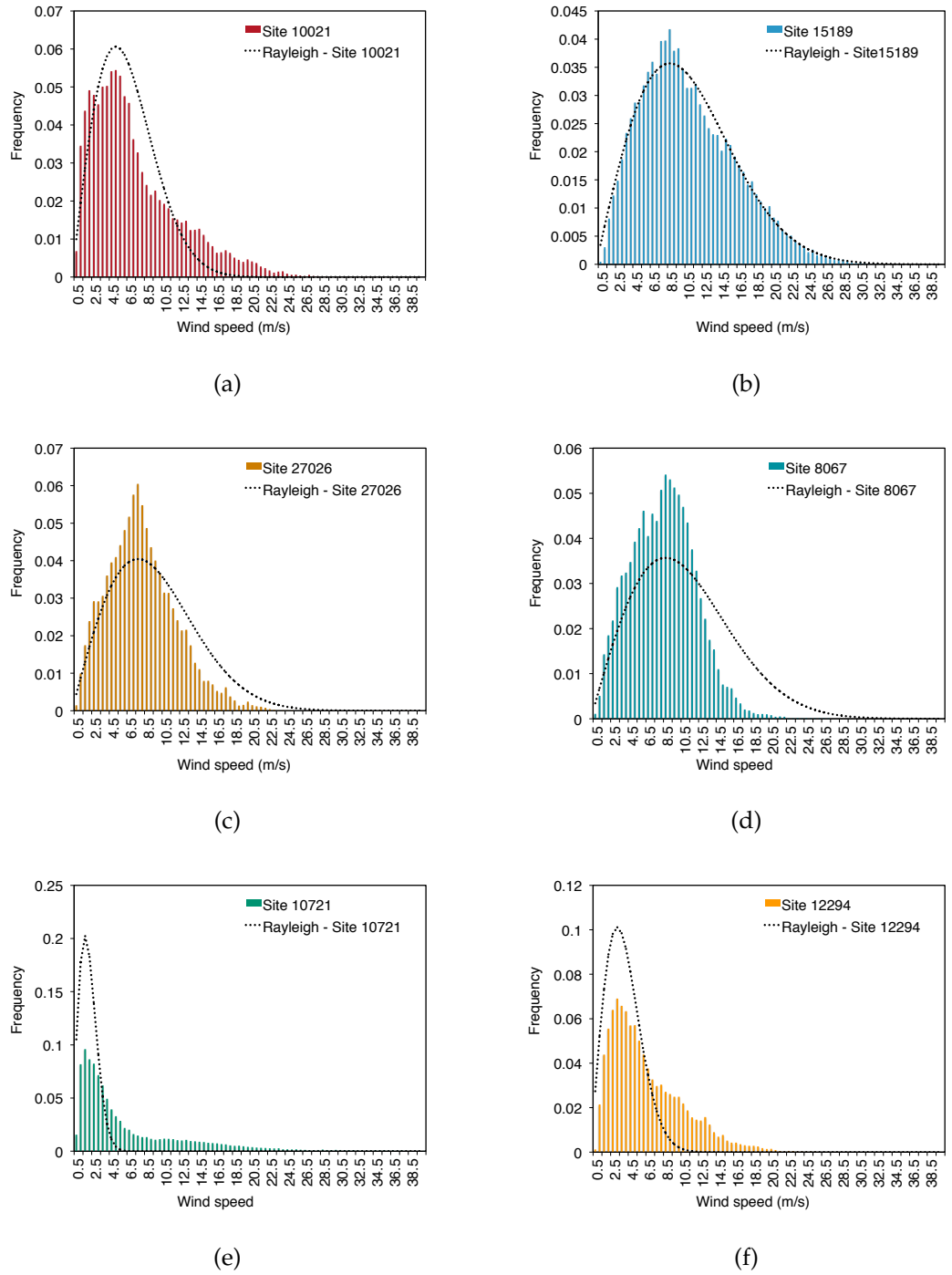

Figure 4.7: Rayleigh distribution fit to 6 wind speed datasets from western United States. Data source: NREL Western Wind Integration Dataset.

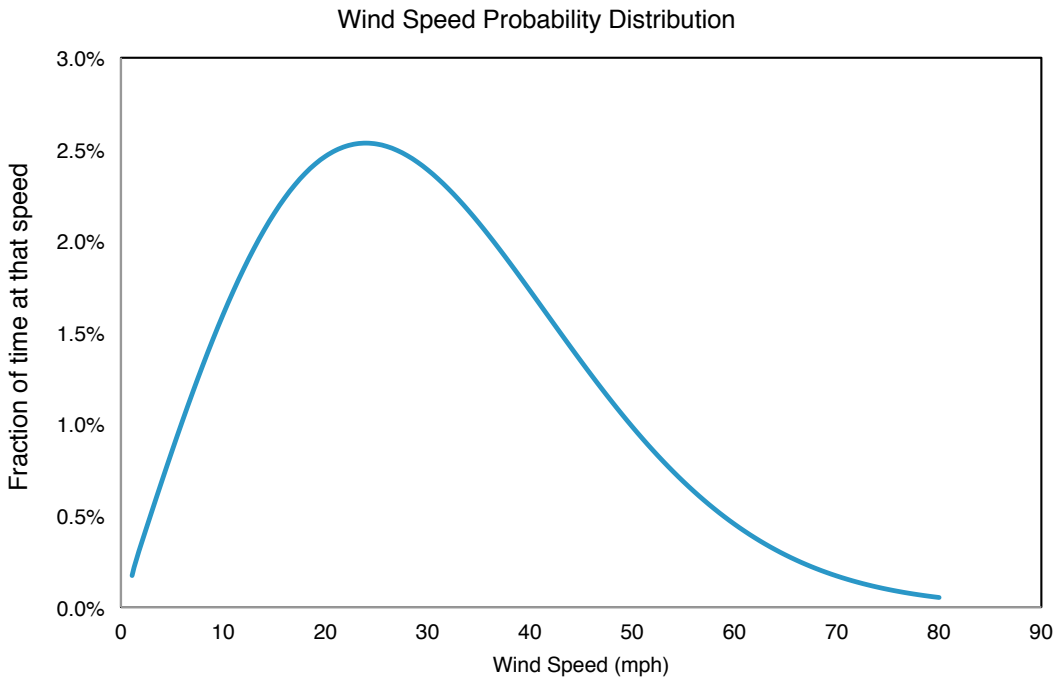

Figure 4.8: Example of OPGEE wind speed distribution for a 30 mph average wind-speed input.

Table 4.21: Default inputs for venting, flaring, and fugitive emissions.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
A	Flaring eff. pre-exponential constant	-	156.4	NA	[MJ/kg]	[142]	
B	Flaring eff. growth constant	-	0.318	NA	[-]	[142]	
d	Flare diameter	-	3	0.25-24	[in]		
$EM_{F,comb}$	Flare combustion emissions	(4.34)	-		[tCO_2eq/d]		
$EM_{F,str}$	Flare stripping emissions	(4.33)	-	-	[tCO_2eq/d]		
η_F	Flaring efficiency	-	0.95	0.54 - $\geq$ 0.99	[-]	[11, 12, 146]	a
FOR	Flaring-to-oil ratio	-	177	11-3010	[scf/bbl]		
g	Gravitational constant	-	9.8	-	[m/sec^2]		
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1	-	[$gCO_2eq./g$]	[138]	b
LHV	Lower heating value of associated gas	-		-	[MJ/kg]		b
Π_i	Stoichiometric combustion ratios	-	Table 4.20	-	[gCO_2/g]	-	c
Q_F	Flaring volume	(4.29)	-	-	[MMscf/d]		
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
ρ_i	Gas density for species i	-	*'Input Data'* Table 2.2	-	[g/ft^3]	-	d
U_∞	Wind speed	-	NA	0-100	[mph]		e
V	Flare exit velocity	-	NA	0-100	[m/s]		f
x_i	Mole fraction of gas composition	-	*'Gas Balance'* Table 1.1	-	[-]	[100]	g

a - Average efficiency for Alberta found to be ≈0.95 across 4 years of data using known wind distributions and flaring volumes [11]. Very low efficiencies are seen in high cross winds and with high fractions of non-combustible gas components (e.g., CO_2, N_2).
b - 100-year GWPs from the IPCC Fourth Assessment Report [138].
c - Standard combustion stoichiometry assuming complete combustion.
d - Standard gas densities [113]
e - The experimental wind conditions in the Johnson (2002) study only ranged from 4 to 38 mph. OPGEE presents a warning if a wind speed outside of this range is entered.

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes

f - The flare exit velocities in the Johnson (2002) study only ranged from 0.5 to 4 m/s (low momentum flares). OPGEE presents a warning if a wind speed outside of this range is entered. For most flare design conditions, flare exit velocities (and momentum ratios) will be higher than this range, and flare efficiency will be at upper end of model results. Johnson suggest (pers. comm. 2012) that for conditions with momentum ratios above the experimental conditions, a default flaring efficiency of 99.8% be used.
g - Gas composition can vary. Default gas composition given from [100].

5 Gathering worksheets

This section explains three worksheets in OPGEE which are used to collect output from intermediate calculations in process stage and supplemental worksheets. This collected output is used to calculate the overall WTR energy consumption and GHG emissions of the study crude. These gathering worksheets are the *'Energy Consumption'*, *'GHG Emissions'*, and *'User Inputs & Results'* worksheets.

5.1 *'Energy Consumption'* gathering worksheet

In the *'Energy Consumption'* gathering worksheet, energy use is summed in order of process stages, from Exploration to Waste disposal. For consistency, all energy inputs are summed on a daily basis, either as thermal energy (MMBtu/d) or as electrical energy (kWh/d). All energy types are classified using a fuel code. The primary energy types included are: 1A) Natural gas; 1B) Natural gas liquids; 2) Diesel fuel; 3) Electricity; 4) Crude oil.

First, the amount and type of fuel consumed by each component of the model (e.g., downhole pump, gas compressor, etc) is collected using nested if then statements. Second, the fuel consumption is summed by fuel type (e.g., natural gas, diesel) to calculate the gross energy consumption.

Energy Consumption Table 2

Energy Consumption Table 3

The gross energy consumption can include double counted energy. For example, the electricity consumed to drive a pump may be generated onsite and the energy consumed to generate that electricity would also be counted as natural gas or diesel, resulting in double counting.

The net energy consumption is calculated by fuel type. The net energy consumption is equal to the gross energy consumption for all fuels except for electricity. The net energy consumption of electricity is calculated as:

Energy Consumption Table 5

$$E_{el,net} = E_{el,gr} - E_{el,gen} \qquad \text{[MMBtu]} \tag{5.1}$$

where $E_{el,net}$ = net electricity consumption [MMBtu/d]; $E_{el,gr}$ = gross electricity consumption [MMBtu/d]; and $E_{el,gen}$ = total electricity generated onsite [MMBtu/d]. The total electricity generated onsite includes electricity generated using an onsite generator or simple turbine and electricity co-generated in the steam generation system, if applicable. In other words, the net electricity consumption is equal to the electricity imported from the grid, if any.

Once the net energy consumption is calculated by fuel type the energy ex-

Energy Consumption Table 4

ports/imports are calculated by fuel type. Energy exports/imports are used to calculate indirect (offsite) energy consumption and GHG emissions by fuel type. Indirect energy consumption and GHG emissions are associated with the production and transport (production only in case of exports) of the fuel consumed directly. The exports/imports of natural gas are calculated as:

$$E_{ng,exp} = E_{ng,gr} - E_{ng,fuel} + E_{ng,mu} - E_{ng,rec} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.2}$$

where $E_{ng,exp}$ = natural gas export/import [MMBtu/d]; $E_{ng,gr}$ = gross natural gas consumption [MMBtu/d]; $E_{ng,fuel}$ = natural gas produced as fuel after gas lifting/re-injection [MMBtu/d]; $E_{ng,mu}$ = make up natural gas for gas flooding [MMBtu/d], if applicable; and $E_{ng,rec}$ = natural gas recovered from venting and fugitives. The produced gas remaining to be used as a process fuel is equal to 0 MMBtu/d in the case of gas flooding where 100% of produced gas is re-injected. Negative $E_{ng,exp}$ represents gas exports. Positive $E_{ng,exp}$ represents gas imports.

The exports/imports of natural gas liquid (NGL) is calculated as:

$$E_{ngl,exp} = E_{ngl,gr} - E_{ngl,fuel} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.3}$$

where $E_{ngl,exp}$ = NGL export/import [MMBtu/d]; $E_{ngl,gr}$ = gross NGL consumption [MMBtu/d]; and $E_{ngl,fuel}$ = amount of NGL produced as fuel [MMBtu/d].

The import of diesel is equal to gross diesel consumption. The export of diesel does not apply because diesel is not produced in upstream operations. The export/import of electricity is equal to electricity net consumption as calculated in eq. (5.1). Positive net electricity consumption is equal to electricity imported from the grid and negative net electricity consumption is equal to electricity exported to the grid. Crude oil export/import does not apply because crude oil is the main product. Any crude oil used as a process fuel on site is subtracted from the amount produced and shipped (see Section 5.3).

Finally, the indirect energy consumption by fuel type is calculated. The indirect energy consumption is calculated as:

Energy Consumption Table 6

$$\begin{aligned} E_{k,ind} &= E_{k,exp}\, E_{k,FC} && \text{for } E_{k,exp} > 0 \\ E_{k,ind} &= E_{k,exp}\, E_{k,DS} && \text{for } E_{k,exp} < 0 \text{ and displacement} \\ E_{k,ind} &= 0 && \text{for } E_{k,exp} < 0 \text{ and allocation by energy value} \end{aligned} \tag{5.4}$$

where k refers to the fuel type; $E_{k,ind}$ = indirect energy consumption [MMBtu/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $E_{k,FC}$ = fuel cycle energy consumption [MMBtu/MMBtu]; and $E_{k,DS}$ = energy consumption of displaced system in case of fuel export [MMBtu/MMBtu]. For details on the energy consumption of fuel cycles and displaced systems, see Section 4.5.

5.2 *'GHG Emissions'* gathering worksheet

The GHG emissions gathering worksheet compiles and computes emissions of all emissions types across all process stages. The first step is the calculation of direct GHG emissions from the different components of the model. Direct GHG emissions are calculated as:

GHG Emissions Table 1

$$EM_{s,k} = E_{s,k,gr}\, EF_{s,k} \qquad \left[\frac{\mathrm{gCO_2eq}}{\mathrm{d}}\right] \tag{5.5}$$

where s = emissions source (e.g., downhole pump driver); k = fuel type; $EM_{s,k}$ = direct GHG emissions from the consumption of fuel k in source s [gCO_2eq/d]; and $E_{s,k,gr}$ = gross energy consumption of fuel k in source s [MMBtu/d]; and $EF_{s,k}$ = emissions factor of source s using fuel k [g CO_2 eq./MMBtu]. This equation does not apply to electricity, where direct GHG emissions are equal to 0 $gCO_2eq./d$.

Next, the GHG emissions from land use, flaring, and venting/fugitives are calculated by process stage. This includes gathering emissions calculated in each process stage and supplemental worksheets.

GHG Emissions Table 1

The next step is the calculation of indirect GHG emissions by fuel import type. The indirect GHG emissions are calculated as:

GHG Emissions Table 2

$$\begin{aligned} EM_{k,ind} &= E_{k,exp}\, EM_{k,FC} && \text{for } E_{k,exp} > 0 \\ EM_{k,ind} &= E_{k,exp}\, EM_{k,DS} && \text{for } E_{k,exp} < 0 \text{ and displacement} \\ EM_{k,ind} &= 0 && \text{for } E_{k,exp} < 0 \text{ and allocation by energy value} \end{aligned} \tag{5.6}$$

where k refers to the fuel type; $EM_{k,ind}$ = indirect GHG emissions from fuel consumption [gCO_2eq/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $EM_{k,FC}$ = fuel cycle GHG emissions [$gCO_2eq/MMBtu$]; and $EM_{k,DS}$ = GHG emissions from displaced system in case of fuel export [$gCO_2eq/MMBtu$]. For details on the GHG emissions of fuel cycles and displaced systems, see section 4.5.

5.3 *'User Inputs & Results'* gathering worksheet

In this worksheet the total energy consumption and GHG emissions are calculated and displayed in graphical form. Both the total energy consumption and total GHG emissions are calculated by process stage (e.g., Production & Extraction). First the total energy consumption is calculated as:

User Inputs & Results 5.1.1. - 5.9.1

$$E_{tot} = \frac{E_{tot,dir} + E_{tot,ind} + EL_{VFF}}{E_{tot,out}} \qquad [\mathrm{MJ/MJ}_{out}] \tag{5.7}$$

where E_{tot} = total energy consumption of the process [MJ/MJ_{out}]; $E_{tot,dir}$ = total direct energy consumption (calculated in the *'Energy Consumption'* worksheet as net energy consumption) [MMBtu/d]; $E_{tot,ind}$ = total indirect energy consumption (calculated in the *'Energy Consumption'* worksheet) [MMBtu/d];

EL_{VFF} = total energy loss from VFF emissions [MMBtu/d]; and $E_{tot,out}$ = total process energy output [MMBtu/d]. The total process energy output is calculated as:

User Inputs & Results 5.1.1. - 5.9.1

$$E_{tot,out} = Q_o \, \mathrm{HV}_o + E_{ngl,blend} - E_{co,net} \qquad [\mathrm{MMBtu/d}] \tag{5.8}$$

where $E_{tot,out}$ = total process energy output [MMBtu/d]; Q_o = volume of oil production [bbl/d]; HV_o = heating value of crude oil [MMBtu/bbl]; $E_{ngl,blend}$ = amount of produced NGL that is added to crude oil [MMBtu/d]; and $E_{co,net}$ = net crude oil consumption, if applicable [MMBtu/d]. The heating value HV for the denominator crude oil can be selected as LHV or HHV.

Fuel Specs 1.1

If the allocation of co-products is done by energy value and not displacement then eq. (5.8) becomes:

$$E_{tot,out} = Q_o \, \mathrm{HV}_o + E_{ngl,blend} - E_{co,net} + |\sum_k E_{k,exp}| \quad \text{and } E_{k,exp} < 0 \tag{5.9}$$

where $|\sum_k E_{k,exp}|$ = absolute sum of all energy exports [MMBtu/d].

Total energy consumption is allocated by process stage using the fraction of direct energy consumed in a stage (not including the energy consumption of electricity generation). The allocation of energy consumption to different process stages has no effect on the total energy consumption.

For each process stage, GHG emissions are broken down into three categories: (i) combustion/land use, (ii) VFF, and (iii) credit/debt. For combustion/land use emissions, the direct GHG emissions and land use GHG emissions associated with the process stage are summed in the *'GHG emissions'* worksheet. The direct GHG emissions from electricity generation, if any, are divided between the production & extraction and surface processing stages based on the shares of total direct energy consumption between these stages.

GHG Emissions Table 1

VFF emissions associated with a process stage are summed from the *'GHG emissions'* worksheet. Indirect GHG emissions calculated in the *'GHG emissions'* worksheet represent the total net credit/debt, which is allocated by process stage using the same allocation method used for allocating the total energy consumption.

GHG Emissions Table 1

GHG Emissions Table 2

Finally, the total energy consumption and GHG emissions from the process stages of crude oil extraction and surface processing of associated fluids are integrated with the total energy consumption and GHG emissions of crude oil transport to the refinery to calculate the life cycle energy consumption and GHG emissions on a well-to-refinery basis. The life cycle GHG emissions, for example, are calculated as:

$$EM_{LC} = EM_{PP,tot} \, \epsilon_{CT} + EM_{CT,tot} \qquad \left[\frac{\mathrm{gCO_2eq}}{\mathrm{MJ}_{ref}}\right] \tag{5.10}$$

where EM_{LC} = life cycle GHG emissions [$\mathrm{gCO_2eq/MJ}_F$]; $EM_{PP,tot}$ = total GHG emissions from the process stages of crude oil production and processing [$\mathrm{gCO_2eq/MJ}_{out}$]; ϵ_{CT} = crude oil transport loss factor (calculated based on the amount of crude

oil lost in transportation) [-]; and $EM_{CT,tot}$ = total GHG emissions from crude transport [gCO_2eq/MJ_{ref}]. 1 MJ_{out} is one MJ of energy output from crude oil production and processing; and 1 MJ_{ref} is one MJ at refinery gate.

User Inputs & Results Tables 1.1 - 1.2 Figures 1.1 - 1.2

The life cycle energy consumption and GHG emissions are shown in tabular and graphical formats with full GHG emissions breakdown. The total GHG emissions has a separate category for VFF emissions. The energy content of fuels lost to VFF emissions is not tracked as a separate category of energy consumption.

6 Fundamental data inputs

A variety of fundamental data inputs and conversions are required in OPGEE. These data inputs are included in the worksheets *'Input data'* and *'Fuel Specs'*. These inputs are described below, organized by broad class of property.

6.1 Global warming potentials

Global warming potentials (GWPs) for gases with radiative forcing are taken from the IPCC Fourth Assessment Report [138]. The GWPs used are the 100-year GWPs.

Input data Table 2.1

6.2 Properties of water and steam

The density of fresh water at 32 °F is used as the base density of water for lifting, boiling and other calculations in OPGEE. Thermodynamic properties of water and steam are required for steam generation calculations. The following data tables are required for use in steam generation calculations in OPGEE:

Input data Table 5.1

- Saturation properties as a function of temperature;
- Saturation properties as a function of pressure;
- Properties of compressed water and superheated steam.

6.2.1 Saturation properties as a function of temperature

Saturation properties of saturated water and steam as a function of saturation temperature are produced using Knovel steam tables [121, Table 1b]. Properties are derived for temperatures starting at 32 °F and in increments of 20 °F from 40 °F to the critical temperature of 705.1 °F. Properties included are liquid and vapor specific volume v [ft^3/lb], specific enthalpy h [Btu/lbm], specific internal energy u (Btu/lbm), and specific entropy s [Btu/lbm °R]

Input Data Table 5.2

6.2.2 Saturation properties as a function of pressure

Saturation properties of saturated water and steam as a function of saturation pressure are produced using Knovel steam tables [121, Table 1d]. Properties are derived for pressures starting at 15 psia in increments of 5 psia from 15 to 2500 psia. Identical properties are included as above.

Input Data Table 5.3

6.2.3 Properties of compressed water and superheated steam

Properties of compressed water and superheated steam are compiled from Knovel steam tables [121, Table 2b]. Pressures are included from 100 to 1500 psia in increments of 100. The following temperatures are included: 32°F and in increments of 20 °F from 40 °F to 1500 °F. Identical properties are included as above.

Input Data Table 5.4

6.3 Properties of air and exhaust gas components

The composition of dry air and densities of gases required in OPGEE are derived from online tabulations [113]. Moisture in atmospheric air varies as a function of temperature and relative humidity. Assumed moisture content is 2 mol%.

Input Data Table 2.2

6.3.1 Enthalpies of air and exhaust gas components

The enthalpy of air and exhaust gas at various temperatures and atmospheric pressure is modeled as described above in the Steam Injection methods description (see Section 4.2). Coefficients for the specific heats of gases as a function of temperature are taken from literature tabulations [123, Table A2-E]. Specific heats are integrated to derive the enthalpy change between two temperatures for combustion products (exhaust gases) and inlet air/fuel mixtures.

Input Data Tables 4.1 - 4.7

6.4 Compositions and properties of fuels

6.4.1 Heating value of crude oil as a function of density

Crude oil heating values are a function of the chemical composition of the crude oil. Crude oil density can be used to determine the approximate heating value (gross and net heating value, or HHV and LHV) of crude oils. Gross and net crude oil heating values (in Btu per lb and Btu per gallon) are presented as a function of API gravity and are given for API gravities from 0 to 46 °API [83, Table 11]. These heating values are converted to SI units and specific gravity for broader applicability.

Fuel Specs Table 1.1

6.4.2 Crude oil chemical composition as a function of density

Crude oil chemical compositions (C, H, S, (O+N)) are given as a function of the density of crude oil [83, Table 9]. Values are interpolated between those given in the table using a relationship for fraction H as a function of API gravity. O + N contents are assumed to sum to 0.2 wt.%. Sulfur content ranges from 5 wt% to 0.5 wt.%, with approximate concentrations derived from Figure 4.2. Carbon mass fraction is computed by difference.

Fuel Specs Table 1.2

6.4.3 Heat of combustion of gaseous fuel components

A variety of properties were collected for gaseous fuel components, including N_2, Ar, O_2, CO_2, H_2O, CH_4, C_2H_6, C_3H_8, n-C_4H_{10}, CO, H_2, H_2S, and SO_2 [147, Chapter 17] [122]. For simplicity, N_2, Ar and all other inert species are lumped and given properties of N_2. The following properties were collected for each species:

Fuel Specs Table 1.3

- Molar mass [g/mol, mol/kg];
- Moles of C and H per mole of each species (for stoichiometric combustion calculations);
- Higher and lower heating value (HHV, LHV) on a volumetric [Btu/scf], gravimetric [Btu/lbm] and molar basis [Btu/mol, Btu/lbmol]. For completeness, gravimetric energy densities in SI units [MJ/kg] are also included.

6.4.4 Refined and processed fuels heating values

The heating values and densities of refined and processed fuels are taken from the CA-GREET model [74] for a variety of fuels.

Fuel Specs Table 4.1

7 OPGEE limitations

7.1 Scope limitations

OPGEE includes within its system boundaries over 100 emissions sources from oil and gas production. The current version of the model (OPGEE v1.1) includes in the system boundaries emissions sources from all major process stages (e.g., drilling and development, production and extraction, surface processing). However, emissions are subject to significant cutoffs, wherein very small emissions sources are neglected as (likely) insignificant in magnitude. Therefore, some emissions sources from exploration, maintenance, and waste disposal are not explicitly modeled. This cutoff is applied because it would be infeasible (and counter-productive) for regulators or producers to model the magnitude of every emissions source.

Production technologies included in OPGEE are: primary production, secondary production (water flooding), and major tertiary recovery technologies (steam injection). Some production technologies are not included in the current version of OPGEE: polymer and chemical EOR, CO_2 EOR, miscible HC flooding, solar thermal steam generation, insitu combustion, subsurface electric heaters, and cold heavy oil production with sand (CHOPS) are not currently included.

7.2 Technical limitations

7.2.1 Production modeling

OPGEE assumes single phase fluid flow in the calculation of the pressure drop between the well reservoir interface and the well head. In reality, there is a simultaneous flow of both fluid (oil and water) and vapor (associated gas). Results show that pressure drop calculated using a two phase flow model can be significantly lower than that calculated using a single phase flow linear model [41]. The deviation of our single phase flow assumption from reality is expected to increase at high GOR.

In the modeling of TEOR, OPGEE does not model changes in viscosity of the oil in lifting calculations [59]. The concept of TEOR is based on reducing the viscosity of the oil, which decreases the lifting energy requirement. This effect is likely to be small because the bulk of the energy consumption in TEOR is from steam generation and not lifting.

7.2.2 Surface processing

It is infeasible in a model such as OPGEE to account for the many possible variations in surface processing. The goal is to include the most frequently applied processes in the industry, while still retaining some flexibility to model varying operating modes (e.g. placement of flow heater in the oil-water separation scheme).

The energy consumption of the demethanizer unit is calculated using energy factors that are generated from a default configuration [111]. Energy factors are calculated in unit energy per kmol of gas feed. Therefore, energy consumption is sensitive to inlet gas composition. However, the use of a default configuration does not allow accounting for the effect of changes in NGL recovery (e.g., 80% ethane recovery). The user can change the amount of NGL produced by changing the fractions of NGL recovered in the *'Surface Processing'* worksheet but this does not have an effect on the demethanizer energy consumption calculations. Emissions from a demethanizer unit are of small significance and therefore do not warrant a full engineering synthesis which can be reconfigured based on user inputs.

7.2.3 Data limitations

7.2.3.1 VFF data

Flaring rates (MMscf per bbl of oil) used in OPGEE are calculated using country level data, which cannot account for variations in field characteristics and practices [140, 141]. Most fugitive and venting emissions in OPGEE are calculated using emissions factors derived from California Air Resources Board (ARB) industry survey data [100]. Challenges include completeness and quality of data collected in the survey (as is common with all survey results). Also, the data are specific to California where environmental regulations and practices are different than other regions.

7.2.3.2 Default specifications

The accuracy of OPGEE results is fundamentally related to data inputs available. All inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or crude blend/M-CON. If only a limited amount of information is available for a given field, most of the input values will remain equal to defaults. In contrast, if detailed-level data are available, a more accurate emissions estimate can be generated.

Some defaults require more flexible ("smart") default specifications. The water-oil ratio (WOR) is a major parameter in influencing GHG emissions. OPGEE includes a statistical relationship for water production as a function of reservoir age. The default exponential relationship is a moderate case parameterized with a variety of industry data. Nevertheless, this relationship

does not work well in predicting WOR for giant fields with very high per well productivity (e.g., Ghawar in Saudi Arabia).

The GOR varies over the life of the field. As the reservoir pressure drops, increasing amounts of gas evolve from oil (beginning at the bubble point pressure if the oil is initially under-saturated). This tends to result in increasing producing GOR over time. Also, lighter crude oils tend to have a higher GOR. Because of this complexity, a static single value for GOR is not desirable. OPGEE uses California producing GORs to generate GORs for three crude oil bins based on API gravity. All data required to generate empirical correlations for GOR are not likely to be available.

7.3 Future work

In the future we will use more detailed engineering sub-models and more comprehensive data analyses to eliminate the limitations of OPGEE model. This includes building a multi-phase flow lifting model for the estimation of pressure drop between the bottomhole and the well head. The multi-phase flow sub-model is specifically important for modeling fields of high gas-liquid ratio (GLR) and depth where the deviation from single-phase assumption estimates is highest. OPGEE will be expanded to include innovative production technologies such as solar steam generation and CO_2 flooding. Larger data sets are collected to improve the correlations of WOR and GOR defaults. Another important initiative is the calculation of field-level flaring rates using high resolution satellite data [148]. This is believed to have significant impact on the accuracy of results from OPGEE. Work-in progress include generating and updating venting and fugitives emissions factors using technical reports. Also a major sub-project for the development of an engineering-based module for the calculation of GHG emissions from oil sands was initiated.

A Terminology: Acronyms and abbreviations

Table A.1: Acronyms and abbreviations.

Acronym or abbreviation	Description
ABS	Absorbents
AGR	Acid gas removal
AIR	Air stripping
AL	Aerated lagoons
ANS	Alaska North Slope
API	American Petroleum Institute
ARB	California Air Resources Board
AS	Activated sludge
BHP	Brake horsepower
CHOPS	Cold heavy oil production with sand
CSS	Cyclic steam stimulation
CWL	Wetlands
DAF	Dissolved air flotation
DEA	Di-ethanol amine
DGA	Diglycolamine
DMF	Dual media filtration
DOGGR	State of California Department of Conservations Division of Oil, Gas and Geothermal Resources
EDR	Electrodialysis reversal
EGOR	Onsite electricity generation to oil ratio
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERCB	Alberta Energy Resources Conservation Board
FOR	Flaring to oil ratio
FWKO	Free-water knockouts
GAC	Granular activated carbon
GGFR	Global Gas Flaring Reduction Partnership at the World Bank
GHG	Greenhouse gases
GLR	Gas to liquid ratio
GOR	Gas to oil ratio
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GT	Gas turbine

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Acronym or abbreviation	Description
GWP	Global warming potential
HHV	Higher heating value
HRSG	Heat recovery steam generator
HYDRO	Hydrocyclones
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LHV	Lower heating value
MEA	Monoethanolamine
MF	Microfiltration
NF	Nanofiltration
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
ORG	Organoclay
OTSG	Once-through steam generators
OZO	Ozone
RBC	Rotating biological contactors
RO	Reverse osmosis
RVP	Reid vapor pressure
SAGD	Steam assisted gravity drainage
SCO	Synthetic crude oil
SOR	Steam to oil ratio
SSF	Slow sand filtration
TDS	Total dissolved solids
TEG	Triethylene glycol
TEOR	Thermal enhanced oil recovery
TF	Trickling filters
THC	Total hydrocarbon
UF	Ultrafiltration
VFF	Venting, flaring and fugitives
VOC	Volatile organic compounds
VOR	Venting to oil ratio
W&S	Standing and working losses
WOR	Water to oil ratio
WTR	Well to refinery

B Mathematical terms and definitions

Mathematical terms and subscripts are defined in Table B.1. Parameters and variables serve as the key signifiers in the formulae. A variety of subscripts are used in the mathematics, and can be divided into:

1. Process stages, represented by a a two- or three-letter capitalized symbol (e.g., DD = Drilling & Development)
2. Sub-processes, represented by two- or three-letter capitalized symbol (e.g. GP = Gas processing)
3. Process flows or environments, represented by lower-case symbols (e.g., a = air)
4. Technologies or technology components, represented by capitalized symbols (e.g., GD = glycol dehydrator)
5. Primary fuels and energy carriers, represented by one- to three-letter lower-case symbols (e.g., di = Diesel fuel)
6. Modifiers, represented by lower-case symbols or word fragments (e.g., avg = averge)
7. Gas species, represented by capitalized species formulae (e.g., $O2$ = oxygen)

In general, a term in the equation will follow the above order as in:

$$[Param]_{[PROCESS][SUB-PROCESS][flow][TECHNOLOGY][fuel][modifier(s)][SPECIES]} \quad \text{(B.1)}$$

if an element is not needed, it is simply excluded. To create a (relatively extreme) example, one might have: $p_{OTSG,ng,avg,in}$, which represents average inlet natural gas pressure to the once-through steam generator. Most equation elements will not require this many elements.

Table B.1: Mathematical symbols and subscripts.

Symbol	Description
Parameters and variables	
α	Solar absorbance
δ	Change
ϵ	Loss
η	Efficiency
γ	Specific gravity
λ	Fraction or share
ρ	Density
$a, b, c, d \ldots$	Constants in fitting equations or from data
C	Capacity
C	Concentration
D	Diameter
API	Degrees API
e	Energy (per unit of something)
E	Energy quantity
EF	Emissions factor
EL	Energy loss
EM	Emissions
f	Friction factor
FOR	Flaring oil ratio
GOR	Gas oil ratio
GWP	Global warming potential
h	Height
h	Enthalpy
H	Head
I	Solar insolation
l	Load factor
m	Mass
MW	Molecular weight
N	Number of something
p	Pressure
P	Power
Q	Flow rate
R	Ratio
r	Radius
RVP	Reid vapor pressure
T	Temperature
U	Effectiveness
v	Velocity
V	Volume
W	Work
w	Mass fraction
WOR	Water oil ratio
x	Mole fraction

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Symbol	Description
y	Binary variable
Process stages (Index = j)	
EX	Exploration
DD	Drilling & Development
PE	Production & Extraction
SP	Surface Processing
MA	Maintenance
CT	Crude Transport
BE	Bitumen Extraction & Upgrading
SI	Steam Injection
EL	Electricity
FC	Fuel cycle
VFF	Venting, flaring and fugitives
LC	Life cycle
DS	Displaced system
PP	Process stages of curde oil production and processing
Sub-processes (Index = j)	
EX	Extraction
GP	Gas processing
IC	In situ production via CSS
IP	In situ productio via primary prod.
IS	In situ production via SAGD
MI	Integrated mining & upgrading
MN	Non-integrated mining & upgrading
UP	Upgrading
Process flows & Environment (Index = i)	
a	Air
atm	Atmosphere
e	Exhaust
f	Fuel
g	Gas
l	Liquid
o	Oil
w	Water
ws	Water as steam
Technologies (Index = j)	
AGR	AGR unit
B	Barge
BP	Booster pump
C	Compressor
CD	Crude dehydrator
CP	Circulation pump
D	Driver

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Symbol	Description
DR	Drill rig
EG	Electricity generator
F	Flaring
F	Fan
F	Fugitives
G	Generator
GD	Gas dehydrator (glycol dehydrator)
GP	Glycol pump
GS	Generator set
GT	Gas turbine
$HRSG$	Heat recovery steam generator
M	Motor
$OTSG$	Once-through steam generator
P	Pipeline
R	Rail
R	Roof
RE	Reciprocating engine
RP	Reflux pump
S	Stabilizer
T	Tanker
T	Tank
V	Vent
W	Well

Fuels and energy carriers (Index = k)

ag	Associated gas
c	Coal
ck	Coke
co	Crude oil
db	Diluted bitumen
di	Diesel
dl	Diluent
el	Electricity
ng	Natural gas
ngl	Natural gas liquids
pg	Processed gas (processed associated gas)
ro	Residual oil
sco	Synthetic crude oil
sg	Still gas

Modifiers

avg	Average
atm	Atmospheric
b	Base
wf	Bottomhole (well-formation)
$comb$	Combusted
dir	Direct

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Symbol	Description
d	Discharge
ent	Entrained
exp	Exported
gen	Generated
gr	Gross
$heat$	Heated
im	Imported
ind	Indirect
in	Input
l	Lost
mu	Make-up
max	Maximum
min	Minimum
net	Net
ot	Other
out	Output
rem	Removed
req	Required
res	Reservoir
rec	recovered
ref	refinery
s	Stages
sc	Standard conditions
str	Stripped
s	Suction
th	Thermal
tot	Total
to	Turn over
wh	Wellhead
$trav$	traverse
$lift$	lifting

Gas species (Index = i)

C	Carbon
$CO2$	Carbon dioxide
H	Hydrogen
$H2O$	Water
$H2S$	Hydrogen sulfide
$N2$	Nitrogen
$O2$	Oxygen

C Tabulated sources for each production stage

The full classification of emissions sources for each production stage is given below in Tables C.1 to C.7.

Each emissions source is classified according to process, sub-process, and specific emissions source. Any variants of that emissions source are listed (if they have material effects on emissions or energy consumption). A sensitivity code is given from 1 to 4 stars (* to ****) based on judgement of the likely magnitude of the source. Lastly, the table indicates whether or not an emissions source is included (incl. = 1 means that the source is included).

Table C.1: Emissions sources from exploratory operations. For inclusion: 0 = not included, 1 = included.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Exploration	Seismic exploration	Terrestrial seismic	Vehicular emissions	-	*	≤ 0.01 g	0
			Data processing	-	*	≤ 0.01 g	0
			Consumed materials (charges etc.)	-	*	≤ 0.01 g	0
			Land use impacts	-	*	≤ 0.01 g	0
		Oceanic seismic	Ship emissions	-	*	≤ 0.01 g	0
			Data processing	-	*	≤ 0.01 g	0
			Consumed materials	-	*	≤ 0.01 g	0
	Exploratory drilling	Terrestrial drilling	Prime mover emissions	-	*	≤ 0.01 g	0
			Land clearing and construction	-	*	≤ 0.01 g	0
			Vents and upset emissions	-	*	≤ 0.01 g	0
			Drilling flares	-	*	≤ 0.01 g	0
			Casing and cement	-	*	≤ 0.01 g	0
			Other material consumption (e.g., frac sand)	-	*	≤ 0.01 g	0
			Land use impacts	-	*	≤ 0.01 g	0
			Indirect land use impacts (opening of inaccessible land)	-	*	≤ 0.01 g	0
		Offshore drilling	Prime mover emissions	-	*	≤ 0.01 g	0
			Drilling flares	-	*	≤ 0.01 g	0
			Vents and upset emissions	-	*	≤ 0.01 g	0
			Casing and cement	-	*	≤ 0.01 g	0
	Waste handling and disposal	Mud and fluid handling	Energy consumption (other than prime mover)	-	*	≤ 0.01 g	0
			Fugitives from mud	-	*	≤ 0.01 g	0
			Disposal of mud	-	*	≤ 0.01 g	0
		Fracturing fluid disposal	Processing and disposal of fracturing fluid	-	*	≤ 0.01 g	0
		Produced water disposal	Processing of produced water	-	*	≤ 0.01 g	0
			Disposal of produced water (remote or on-site reinjection)	-	*	≤ 0.01 g	0

Table C.2: Emissions sources from drilling operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Drilling and development	Developmental drilling	Terrestrial drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Land use impacts	-	**	0.1 g	1
			Clearing and construction	-	*	$\leq$ 0.01 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
			Other materials consumption (e.g., frac sand)	-	*	$\leq$ 0.01 g	0
		Oceanic drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
	Processing capital investment	Oil/gas/water separators	Separator assembly	-	*	$\leq$ 0.01 g	0
			Separator fabrication	-	*	$\leq$ 0.01 g	0
			Separator transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
		Water reinjection wells	Various drilling emissions from reinjection wells (see above)	-	*	$\leq$ 0.01 g	0
		Pumps	Pump assembly	-	*	$\leq$ 0.01 g	0
			Pump fabrication and raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Pump transport	-	*	$\leq$ 0.01 g	0
	Storage capital investment	Storage capital investment	Tank assembly	-	*	$\leq$ 0.01 g	0
			Tank fabrication	-	*	$\leq$ 0.01 g	0
			Tank transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Transport capital investment	Pipeline capital investment	Pipeline assembly	-	*	$\leq$ 0.01 g	0
			Pipe fabrication	-	*	$\leq$ 0.01 g	0
			Pipe transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
		Other transport capital investment	Other infrastructure fabrication and assembly	-	*	$\leq$ 0.01 g	0

Table C.3: Emissions sources from production and extraction operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Production and extraction	Lifting	Pumping	Combustion for pump driver	-	***	1 g	1.0
			Electricity for pump driver	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
		Gas lift	Compressor prime mover emissions	-	***	1 g	1.0
			Compression electricity emissions	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
	Injection	Gas injection	External gas processing (e.g., N2 production)				1.0
			Gas compression energy		***	1 g	1.0
			[-] Gas sequestration credit (CO2 flood)	-	***	1 g	0.0
		Water injection	Water pumping energy	-	***	1 g	1.0
		Steam injection	Water pre-treatment	-	*	¡= 0.01 g	0.0
			OTSG fuel combustion	NG, produced oil	****	10 g	1.0
			Turbine gas consumption (combined cycle)	Low, med, high efficiency	****	10 g	1.0
			HRSG duct firing (combined cycle)	-	***	1 g	1.0
			[-] Electricity co-production offsets (combined cycle)	Grid mix variation	****	10 g	1.0
			Steam pumping energy (if any)	-	*	¡= 0.01 g	0.0
		Polymer flood	Polymer embodied energy	-	*	¡= 0.01 g	0.0
			Polymer mixing	-	*	¡= 0.01 g	0.0
			Polymer/water mixture pumping energy	-	*	¡= 0.01 g	0.0
		Surfactant/other injection	Surfactant/other embodied energy	-	*	¡= 0.01 g	0.0
			Surfactant/other mixing	-	*	¡= 0.01 g	0.0
			Surfactant/other mixture pumping energy	-	*	¡= 0.01 g	0.0

Table C.4: Emissions sources from surface processing operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Separation and surface processing	Fluid separation	Oil-water-gas separation	Oil-water-gas separation	-	**	0.1 g	1
			Oil-water-gas separation with heater-treaters	-	**	0.1 g	1
			Associated gas venting	Variations in flare efficiency	****	10 g	1
			Associated gas flaring	Variations in flare efficiency	****	10 g	1
	Solid/fluid separation	Solid separation from fluids	Solids removal from separation	-	*	$\leq$ 0.01 g	0
	Gas processing	Gas processing	Produced gas dehydration	-	*	$\leq$ 0.01 g	1
			Produced gas venting and flaring	-	***	1 g	1
	Water treatment and disposal	Water treatment	Produced water cleanup	-	**	0.1 g	1
			Produced water handling and pumping	-	**	0.1 g	1
		Water reinjection and disposal	Produced water reinjection	-	***	1 g	1
			Produced water disposal	-	**	0.1 g	1
	Storage (as part of separation)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

Table C.5: Emissions sources from maintenance operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Maintenance and workovers	Well workover	Terrestrial well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts	-	*	$\leq$ 0.01 g	0
		Offshore well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts		*	$\leq$ 0.01 g	0
	Other maintenance	Other maintenance	Solids removal from separation	-	*	$\leq$ 0.01 g	0

Table C.6: Emissions sources from waste treatment and disposal operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Waste treatment and disposal	Water processing waste	Water treatment waste disposal	Subsurface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
			Surface disposal of separated solids	-	*	$\leq$ 0.01 g	0
			Surface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
	Other waste separation and disposal	Other waste separation and processing	Other waste separation and processing	-	*	$\leq$ 0.01 g	0
			Other waste storage	-	*	$\leq$ 0.01 g	0
			Spills and other upsets	-	*	$\leq$ 0.01 g	0
		Other waste disposal	Other waste transport	-	*	$\leq$ 0.01 g	0
			Other waste disposal (non-hazardous)	-	*	$\leq$ 0.01 g	0
			Other waste disposal (hazardous)	-	*	$\leq$ 0.01 g	0
	Solid waste disposal and project decommissioning	Solid waste disposal	Solid waste separation and processing	-	*	$\leq$ 0.01 g	0
			Solid waste transport and disposal	-	*	$\leq$ 0.01 g	0
		End of life and decommissioning	Demolition and decommissioning	-	*	$\leq$ 0.01 g	0
			Scrap and waste disposal	-	*	$\leq$ 0.01 g	0
			[-] Credit for waste recycling (embodied energy)	-	*	$\leq$ 0.01 g	0

Table C.7: Emissions sources from crude transport.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Crude product transport	Pipeline transport	Pipeline transport	Combustion for pump prime mover	-	***	1 g	1
			Electricity for pump use	-	***	1 g	1
			Process upsets (one-time events)	-	*	$\leq$ 0.01 g	1
			Leaks (pipeline losses)	-	***	1 g	1
		Pipeline construction	Construction equipment energy use	-	*	$\leq$ 0.01 g	0
			Embodied energy in pipeline materials (cement and steel)	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Tanker transport	Tanker transport	Combustion in tanker prime mover (bunker fuels)	-	***	1 g	1
			Loading and unloading pumping	-	*	$\leq$ 0.01 g	1
			Flares	-	*	$\leq$ 0.01 g	1
			Vents, leaks and upsets	-	*	$\leq$ 0.01 g	1
		Tanker construction	Embodied energy in tanker materials (steel)	-	*	$\leq$ 0.01 g	0
			Construction energy	-	*	$\leq$ 0.01 g	0
	Storage (as part of transport)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

D Bulk assessment macro error correction

The bulk assessment machinery is capable of fixing errors, performing iterative calculations and adjusting input parameters where necessary. It is not practical to perform these computational tasks manually when assessing a large number of projects (100+). The built-in macro ensures consistent treatment across all fields. Errors that are addressed in the macro include:

- Discrepancies between country-average default flaring rate and entered GOR (e.g., flaring module predicts more flaring than field has available);
- Discrepencies between default fugitive emissions of gaseous components and gas available from production;
- Requirement to iteratively solve for the gas composition in the wellbore in the case of gas lift;
- Error with productivity index resulting in negative bottomhole pressures;
- Error resulting from very large frictional lifting penalties due to too-small assumed wellbore;
- Requirement to iteratively solve for gas reinjected to result in 0 gas export.

Figure D.1 shows the logic of errors fixing and entry adjustments related to GOR and gas composition. Other errors and adjustments are shown in Figure D.2. One of the most common errors encountered in running OPGEE is the gas composition error which can result in more than one case of data inconsistency. First, the macro checks to ensure that GOR is at least 10 to satisfy the requirements for leaks in the other sections of the model (not shown in flow chart). Then, the macro tackles the most common gas-related errors are related to flaring and fugitive emissions. First, relying on country-average flaring rates in combination with field-specific GOR can result in flaring more gas than that which is produced. As shown in Figure D.1 the gas composition error is fixed by either increasing GOR to match flaring or decreasing flaring to match GOR. The choice between the two options is based on the input data quality. If flaring volume is default then flaring is adjusted. If GOR is default then GOR is adjusted. If both flaring volume and GOR are user inputs then

GOR is adjusted because we assume that the flaring rate, being measured by satellite, is more likely to be accurate than the default GOR.

Another problem is having insufficient CO_2 and VOC in the gas stream to match default system losses from venting and fugitives (see Figure D.1 "Gas Comp Error?"). If this occurs, the GOR is increased by 10 scf/bbl until sufficient gas is available to provide emissions estimates.

In the case of gas lift, the gas composition in the wellbore is not the reservoir gas composition. The product gas is injected into the well stream, re-processed and re-injected again in a continuous cycle. Therefore the gas at the wellhead separator is a mixture of both the reservoir and product gases. The bulk assessment machinery reconfigures the gas composition by combining the product and reservoir gases in consecutive iterations until the gas composition stabilizes. As shown in Figure D.1 before reconfiguring the gas composition the GOR is adjusted to add the amount of gas injected into the well stream.

Figure D.2 shows the error fixes and adjustments not related to GOR or gas composition.

The second most common error encountered in running OPGEE is the productivity index (PI) error which results when the user or default PI value does not satisfy the minimum bottomhole pressure requirement (0 psi). The bulk assessment fixes the PI error by incrementally increasing the PI value until the error resolves.

After this, the macro checks for the friction pressure traverse (p_f) as a fraction of total pressure traverse (p_{trav}). In cases where the friction pressure traverse accounts for more than 25% of the total pressure traverse, it is assumed that this is not a realistic system design (e.g., designers would account for and reduce large friction penalties due to effects on lifting costs). Such assumptions are supported by the literature, where the nominal range of the friction pressure traverse is assumed not to exceed 25% of the total pressure traverse [84]. To address this problem, the bulk assessment macro widens the well diameter (D) in increments of 0.25 in. until the friction pressure traverse is $\leq$25%.

Finally, if the user chooses to set gas export to zero as opposed to default setting where remaining gas is exported, the bulk assessment machinery increases the gas reinjection fraction by increments of 0.5% until no remaining gas is exported. **To set gas export to $\approx$0 scf the user must enter -1 in the fraction of remaining gas reinjected.**

Colors are used to highlight where the bulk assessment fills in or adjusts data. OPGEE *green color* represents default values. OPGEE *yellow color* represents adjusted parameters. And OPGEE *red color* represents warnings in case the adjusted parameter exceeds literature range / design standards (e.g., >4.5 inch production well diameter) [41, p. 106].

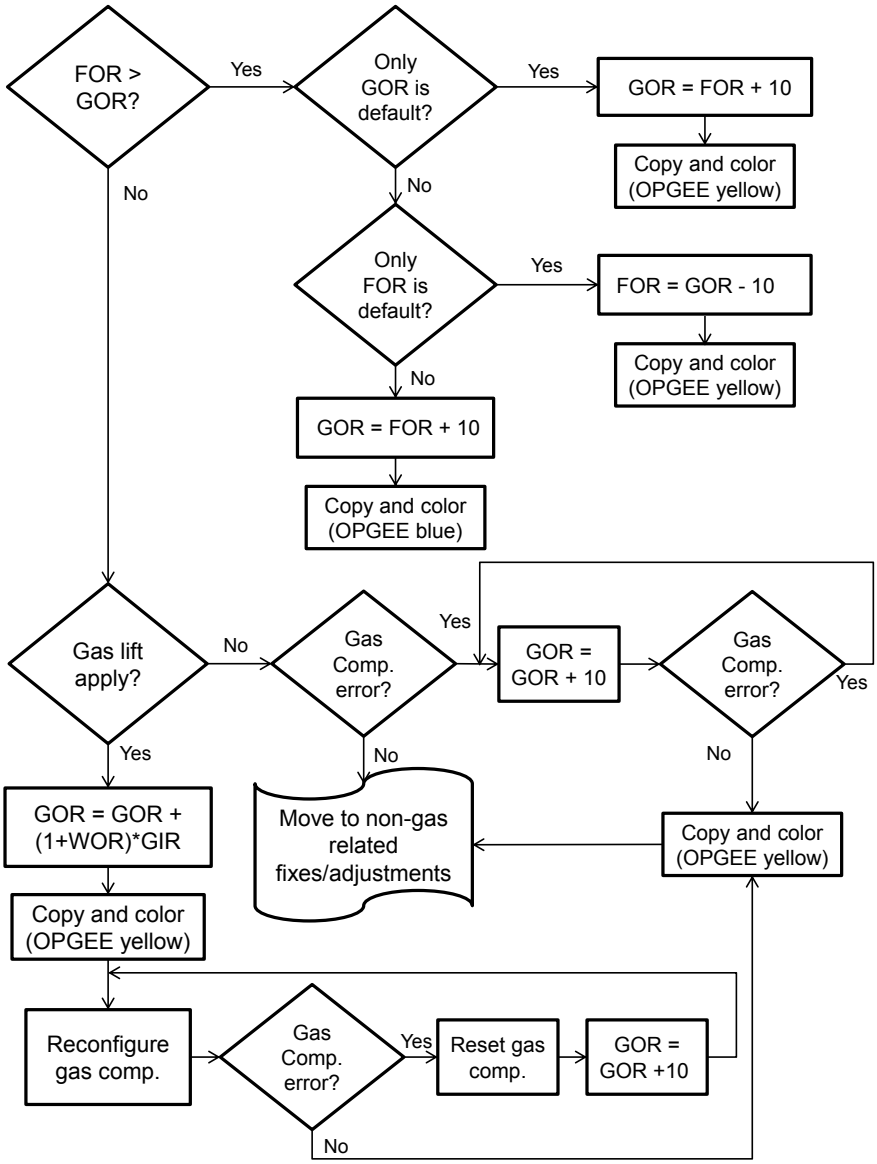

Figure D.1: The errors fixing/entries adjustment logic.

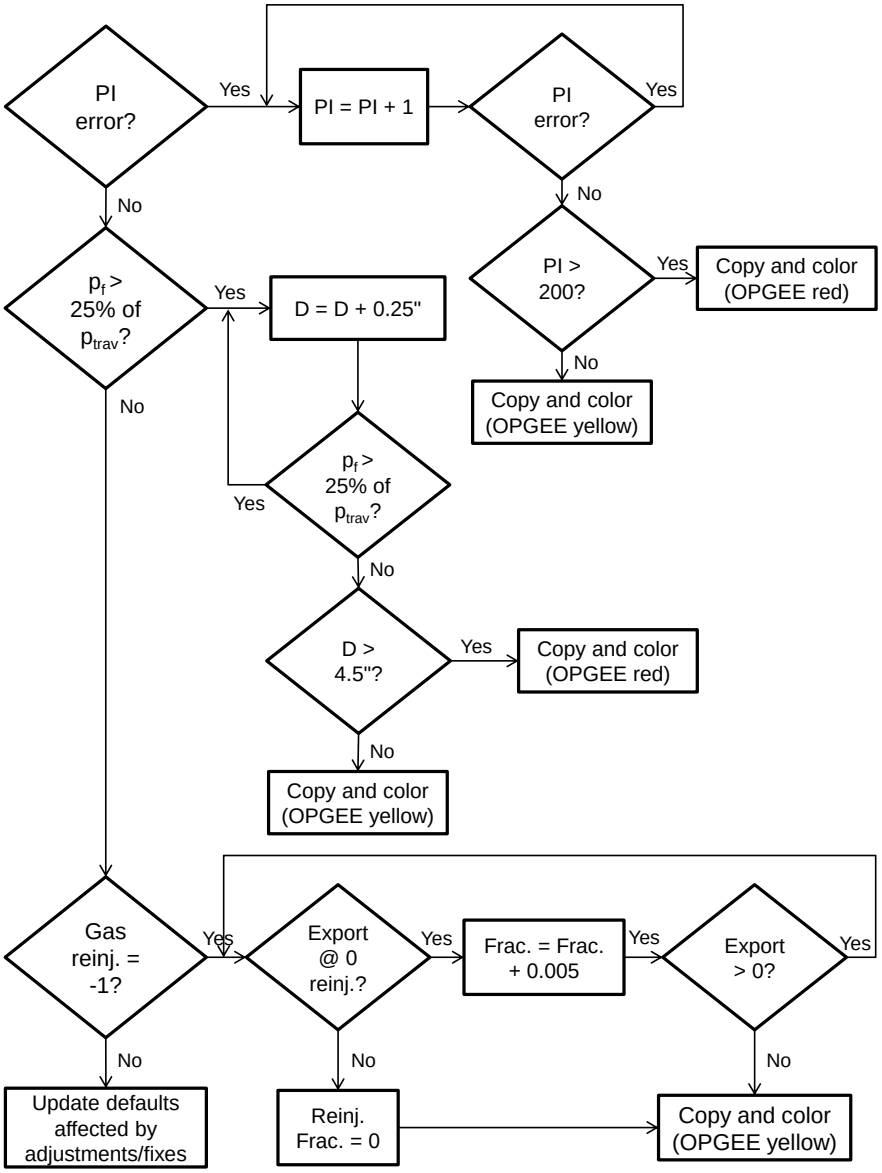

Figure D.2: The errors fixing/entries adjustment logic for non-GOR, gas composition related entries.

E Changes and updates from previous versions of OPGEE

E.1 Changes and updates from OPGEE v1.0 to OPGEE v1.1

E.1.1 Overall model organization

- Added worksheet to track model changes
- Changed color themes to OPGEE custom color theme

E.1.2 User inputs & results worksheet

- Organized user inputs worksheet for the implementation of new macro for the bulk assessment
- Allowed removal of gas processing units on the user inputs worksheet
- Added ocean tanker size to user inputs worksheet
- Added volume fraction of diluent as a user input
- Added a separate emissions category for diluent life cycle emissions
- Removed the allocation of off-site GHG emissions (credits/debts)
- Added a separate emissions category for total off-site GHG emissions

E.1.3 Defaults and smart defaults

- Rounded no. of injection wells to the nearest 1 well

E.1.4 Data and input parameters

- Modified land use change emissions factors to account for 30 year analysis period
- Added petroleum coke life cycle energy consumption and GHG emissions

E.1.5 Error checks

- Corrected the *'Gas Balance'* gas composition overall error check
- Added error check to ensure that downhole pump and gas lift do not co-exist (results in miscalculation of required lifting work)
- Added error check to ensure that user input for volume fraction of diluent is not less than the volume fraction of NGL produced onsite as crude oil blend

E.1.6 New model functionality

- Added improved flaring efficiency calculation worksheet
- More detailed demethanizer model now includes energy consumed by demethanizer
  - Added demethanizer input data
  - Added N_2 and H_2S gas densities to input data worksheet
  - Calculated gas feed into demethanizer in kmol
  - Updated gathering worksheets to include energy consumption and emissions of demethanizer

E.1.7 Bulk assessment macro changes

- Developed a new macro which runs the bulk assessment for unlimited number of fields and has a built in logic for errors fixing
- Bulk assessment macro now has the following features:
  - Works with limited datasets, and fills in defaults or smart defaults where applicable
  - Resolves errors by changing programmatically the well diameter, productivity index, GOR etc. See Section 2.5 for details.
  - Uses colors to highlight where the macro fills in or alters data
- Processing configuration flexibility
  - Dehydrator can be switched ON/OFF
  - AGR unit can be switched ON/OFF
  - Demethanizer can be switched ON/OFF
- Diluent blending and upgrading for non oil sands heavy crudes

- Developed the option of diluent blending after production. The model now accounts for indirect GHG emissions associated with importing NGL for use as diluent. Added an ERROR check to make sure that the diluent volume fraction is the minimum as indicated by model inputs (minimum is NGL produced onsite as crude oil blend).
- Calculated non-integrated upgrader emissions and energy consumption for non-bitumen pathways using upgrading data from bitumen worksheet
- Added emissions and energy consumption of non-integrated upgrader (if applicable) to conventional oil GHG emissions

E.1.8 Corrections and improvements

- Changed heater/treater calculations using default oil emulsion (14% emulsified water)
- Corrected the AGR unit venting emissions calculation
- Heating value basis in Bitumen Extraction & Upgrading worksheet is changed from HHV basis to LHV basis to address error in emissions computation
- Fixed treatment of imported vs. on site energy at bitumen production facilities and clarified use of fuel cycle emissions for imported fuels
- Diluted bitumen pathways now exhibit sensitivity in flaring and fugitive emissions computations to level of diluent blending. Upstream flaring and fugitive emissions from diluent life cycle are tracked in the *'Fuel Cycle'* worksheet, and therefore should not be double counted in the *'Bitumen Extraction & Upgrading'* worksheet.
- Improved compressor model (compressor now between 1 and 5 stages)
- Corrected two typo mistakes in the bulk assessment worksheet (scf/bbl liquid for gas lift injection and C4+ instead of C4 for gas composition)
- Corrected flaring emissions calculations (use preprocessing gas composition)

E.1.9 Documentation and model explanation

- Highlighted changes to heater/treater calculations
- Improved description of offsite credits/debts
- Fixed error in documentation of small sources

- Labeling of *'Bitumen Extraction & Upgrading'* Table 4.10 fixed
- Fixed numbering in Bitumen Extraction & Upgrading worksheet

E.2 Changes from OPGEE v1.0 Draft A to OPGEE v1.0

Draft version A of the model was released on June 22nd, 2012 for public review and commenting. A public workshop which was held on the July 12th, 2012 at California Air Resources Board, Sacramento. In this appendix the comments received at this meeting and at other times are addressed as described below.

E.2.1 Major changes

- The version released to the public is now the same as the "pro" version of the model. The public version of the model now contains the macro to run up to 50 fields at one time. See worksheet *'Bulk Assessment Tool'*, which allows the user to run multiple cases at once.
- Complex storage tank emissions calculations were removed from OPGEE v1.0 Draft A and replaced with a single parameter. At this time, it was judged that the scale of tank emissions (relatively small) and the complexity with which they were addressed (high complexity) were incommensurate. This is especially the case given the large numbers of parameters needed for the storage tank emissions model, many of which would not likely be available to users of the model. In place of the complex tank calculations, an average tank emissions factor from California data is included.
- The *'User Inputs & Results'* worksheet was significantly expanded to allow easier running of the model with less need to access the detailed calculation worksheets. Parameters added to the *'User Inputs & Results'* worksheet include: fraction of steam generated via cogeneration for thermal enhanced oil recovery projects; field productivity index; and well production tubing diameter.
- An option is now added to deal with the co-production of oil and other products (NGLs, gas, etc.): OPGEE v1.0 Draft A only treated co-production with system boundary expansion, while in OPGEE v1.0 Draft B, allocation of emissions by energy content is allowed. In system boundary expansion (also known as co-product displacement or co-product credit method), an alternative production method for the co-produced product is assessed and the resulting emissions are credited to the main product as if the co-product directly displaces material produced elsewhere. In allocation, the emissions are divided between products and co-products

in proportion to some measure of output (often energy, mass, or monetary value). The user can now choose the co-product treatment method on the *'Fuel Cycle'* worksheet.

- OPGEE was updated with data from the CA-GREET variant of the GREET model. This update allows better congruence with other California LCFS calculations, which rely on the CA-GREET model. The data inputs changed include fuel properties and upstream (fuel cycle) emissions for use in co-product displacement calculations.
- All calculations were updated to use lower heating values instead of higher heating values. The user can still choose the heating value metric for the denominator energy content of the final result (e.g., g/MJ LHV or g/MJ HHV crude oil delivered to refinery).
- Water injection pressure is now calculated using reservoir pressure and an injectivity index (bbl/psi-well). This is more in line with the calculation of work to lift fluids.

E.2.2 Minor changes

- The user guide is expanded with additional descriptions of the input parameters on the *'User Inputs & Results'* worksheet to reduce uncertainty about the definitions of parameters. These descriptions are included in Section 2.4.1.
- More explanation is given in tables regarding parameters that are outside of literature ranges (e.g., pump and compressor efficiency).
- More attention is drawn to the overall model error check indicator to alert the user to possible errors in model inputs.
- An error is reported when a user puts in an incorrectly spelled country name. This prevents spurious default to average flaring emissions rates that might occur due to simple input errors.
- To address transmission losses between pumps and prime movers, pump efficiency is slightly reduced. This is believed to be a minor factor, and data are not currently available to separate transmission losses from other losses.
- The value for flaring emissions on the *'User Inputs & Results'* worksheet (J99 in OPGEE v1.0 Draft A) is now used to compute flaring emissions.
- The friction factor is now included as a 'User Free' cell instead of a fixed default. This will allow the user to reduce the friction factor in cases of very high well flow rates (flow character in turbulent regime).

- Water reinjection pump suction pressure is added as a parameter to allow for high pressure oil-water separation and resulting reduced pump work.
- Conversion factor from grams to pounds changed to 453.59 g/lb from 453.
- The units that accompanied cell *'Bitumen Extraction & Upgrading'* M164 in OPGEE v1.0 Draft A, are corrected from g/bbl to g/MJ.
- GWP values are allowed to vary for examining differences using 20 and 100 year GWPs.

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