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Life Cycle Assessment of a Catalytic Steam Cracking (CSC) Process for Partial-Upgrading of Heavy Oil

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Life Cycle Assessment of a Catalytic Steam Cracking (CSC) Process for Partial-Upgrading of Heavy Oil

by

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Abstract

The development of Life Cycle Assessment (LCA) framework that allows for direct comparison with current industrial pathways is required for characterizing GHG emissions impacts and informing economic energy systems decisions regarding an emerging Catalytic Steam Cracking (CSC) partial-upgrading process. Through characterization of the CSC partial-upgrading at a pilot plant scale, industrial scale process modeling and inclusion in a well-to-wheels (WTW) spreadsheet model, the relative emissions impacts of the emerging pathways are directly compared with current dilution and full-upgrading pathways. Consideration for current and future emissions policies allowed for the inclusion of greenhouse gas (GHG) emissions costs in a project investment comparison of CSC partial-upgrading with full-upgrading and dilution options. The case study results for GHG emissions and subsequent economic evaluations suggest that CSC partial-upgrading could have a higher project net present value (NPV) under stringent economy wide carbon prices (>\$80 per tonne CO_2e).

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Table of Contents

List of Tables

List of Figures

List of Abbreviations, Symbols and Nomenclature

Abbreviation	**Definition**
API	American Petroleum Institute gravity. A relative measurement of the density of the petroleum product to water
Asphaltenes	A class of heavy and highly viscous crude oil components which are found in significantly higher proportions in Bitumen compared with light oils.
Bbl	Barrel
Bpd	Barrels per day
Bitumen	Semi-solid form of petroleum that is naturally occurring in the Canadian Oil Sands
C	Carbon
CARB	California Air and Resource Board
CCS	Carbon Capture and Storage
CFC	Chlorofluorocarbons
Coke (Petroleum Coke)	A solid residue which is often produced as a by-product from delayed coking
CO_2e	Carbon dioxide equivalent
CSC	Catalytic Steam Cracking
CSS	Cyclic Steam Stimulation
DAO	Deasphalted oil – Refers to a fraction of the oil which has been processed by a de-asphalting unit that separates pitch/asphalt from crude oil or bitumen
Dilution	The process of mixing hydrocarbons to obtain viscosity and density properties required for transportation
Dilbit	The product of diluting bitumen with a solvent such as Naphtha
Full-Upgrading	The process of converting the bitumen to a high quality product (API > 25^o)

Abbreviation	Definition
Full-SCO	The product of full upgrading
GHG	Greenhouse gas
GHGenius	Model for life cycle assessment of transportation fuels with an emphasis on Canada
GHOST	Greenhouse gas emissions of current Oil Sands Technologies (GHOST) life cycle model for extraction and upgrading
GREET	The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model
H	Hydrogen
Hydrocarbon	An organic compound consisting of carbon and hydrogen
K	Potassium
LCA	Life cycle assessment
LCFS	Low Carbon Fuel Standard
LHVS	Space velocity
Lights/Light ends	Fraction of crude with the lowest boiling points; often a distillate product from an atmospheric distillation tower
MB	Mass Balance
MCR	A petroleum characterization measurement to indicate the tendency of forming solids
MJ	Megajoule
N	Nitrogen
Ni	Nickel
NPV	Net present value
O	Oxygen
O&M	Operating and Maintenance costs
Partial-SCO	The product of partial upgrading

Abbreviation	Definition
Partial-upgrading	The conversion of heavy oil into a lighter quality product with an API gravity generally between 15^{o} and 25^{o}
Pitch	Also referred to as Petroleum Asphalt, Petroleum Pitch, Asphaltene Pitch and Asphalt (see Asphaltenes)
Ppm	Parts per million
PRELIM	Petroleum Refinery Life-cycle Inventory Model (PRELIM) which quantifies energy use and GHG emissions for refinery processing
Residue	Very heavy components crude oil which are the bottoms products from distillation (unable to boil). Increased relative amounts of residue is a characteristic of extra heavy oils (Bitumen)
S	Sulphur
SAGD	Steam-assisted Gravity Drainage
SCO	Synthetic Crude Oil
SDA	Solvent De-asphalting
SGER	Specified Gas Emitters Regulation
SimDist	Simulated Distillation – Gas chromatography method used to characterize boiling point information of crude oils
TTW	Tank-to-wheels
VGO	Vacuum gas oil – Refers to a fraction of the oil which has been obtained from vacuum distillation
WTR	Well-to-refinery
WTW	Well-to-wheels

1.0 Introduction

1.1 Motivation

Over the past decade, world energy demand has significantly increase; for example, total primary energy consumption per capita increased from 69.3 to 78.5 gigajoules per person from 2000 to 2010 [US energy information administration, 2013]). That combined with a net population increase of approximately 800 million people over the same period, [US department of Commerce, 2013] results in a net increase of global primary energy demand of greater than 25% over that decade. Growing global energy consumption trends have created significant opportunities and challenges for energy systems, especially in the face of aging infrastructure in North America. With fossil fuels shares of the total worldwide energy mix projected to remaining above 75% for the next two decades, [IEA World Energy Outlook 2012] it is evident that crude oil energy system decisions will play a crucial role in meeting increasing global energy requirements.

Canada is a significant energy producer with 17,032 PetaJoules produced in 2008 and over one third of the total energy production coming in the form of crude oil [US energy information administration, 2013]. The crude oil production in the province of Alberta is primarily from an unconventional resource, commonly referred to as Oil Sands, which account for approximately 97% of Canada total oil reserves [Alberta Energy, 2013]. The oil sands are predicted to have steady production growth with projected increases from 1.9 million barrels per day (bpd) in 2012 to 3.8 million bpd in 2022 [ERCB, 2013]. This anticipated growth in the oil sands industry presents unique challenges and opportunities with respect to energy system decisions; with industrially proven energy system options as well as emerging technology options for developing unconventional oil resources with uncertain future markets and regulations. Informed investment decisions regarding these energy system options requires consideration for capital and operational costs, future crude and utility prices, taxes, royalties and emissions policies. Demonstration plants for emerging technologies can be used as the basis of the assessment and scaled up to estimate industrial level environmental and economic impacts. However, these plants can be very expensive energy system infrastructure projects. Therefore, characterizing these emerging technologies at a pilot plant scale and projecting industrial process performance can be used for direct comparison with current industrial processes to identify potential trade-offs and benefits early in the process development.

With climate change posing a threat to public health, economic well-being, and the environment, environmental impacts have become increasingly scrutinized in the development of energy systems. The adoption of sustainable development practices and carbon pricing policies internationally, as early as 1990 in Finland and more recently within North America [Vourc'h, 2000. Province of BC, 2013.], has increased focus on developing technologies to reduce Greenhouse Gas (GHG) emissions. These GHG policies focus on airborne molecules including CO_2, CO, N_2O, CH_4 and chlorofluorocarbons (CFC), which have been found to affect the temperature of the earth due to adsorbing and emitting infrared radiation [Working Group I, 2013]. The internalization of these carbon emissions costs in energy systems investment decisions is essential to account for current environmental legislation and potential future policies over the lifetime of these energy system decisions.

1.2 Research Question

Consideration of potential environmental emissions impacts in a techno-economic analysis of emerging technologies in direct comparison with current industrial practices can better inform future energy systems decisions in the development of the oil sands. This thesis uses an integrated life cycle assessment (LCA) framework for the early stage assessment of a partial-upgrading pathways which employs a catalytic steam cracking (CSC) upgrading technology that is currently deployed at a pilot plant scale (limited processing capacity up to kilograms of crude oil per day). Comparison of industrial implementation estimates for the prospective CSC partial-upgrading with current oil sands pathways of dilution or full-upgrading (with typical processing capacities of tonnes or kilotonnes of crude per day) are used to inform the potential GHG emissions and economic impacts of these energy systems investment and to better direct development of CSC partial-upgrading through identifying processes or process requirements with critical GHG emissions impacts.

A methodological framework for comparison of emerging technologies with proven energy systems uses analysis of the performance of CSC partial-upgrading at a pilot plant scale, estimation of industrial scale process impacts, and integration of the LCA framework for a techno-economic comparison of energy systems. This assessment includes calculating the mass and energy inputs and outputs for the partial-upgrading process, characterizing the upgraded product and scaling the process requirements to represent their potential performance at industrial scale. Engineering process simulation modeling and literature correlations are used to estimate the process requirement, GHG emissions and economic impacts for potential industrial scale implementation of this CSC partial-upgrading process. Further development of an established integrated LCA evaluation tool allows the calculation of life cycle GHG emissions, from extraction of the raw bitumen to end use of crude oil products, for the CSC partial-upgrading pathway and enables direct comparison with full-upgrading and dilution pathways. Finally, analysis of these GHG impacts with respect to environmental policies and integration into economic modeling is used to inform stakeholders of the potential for CSC partial-upgrading in comparison with current full-upgrading and dilution case studies.

1.3 Oil Sands Pathways

The Canadian oil sands have presented the country with unique the opportunities and challenges that come with having the third largest oil reserves in the world and the largest heavy oil reserves from a non-OPEC (Organization of Petroleum Exporting Countries) country [Alberta Energy, 2013]. In contrast to conventional oil resources, the high viscosity of the extra heavy oil, known as bitumen, requires innovative techniques for extraction and processing. Bitumen is found in loose or partially consolidated sandstone deposits along with a mixture of sand, clay and water.

There are multiple technology and processes used for the development of the Canadian oil sands. First, this unconventional oil source which is a very dense and extra viscous form of petroleum needs to be accessed. When the deposit is less than 75 meters below ground, surface mining is typically used for extraction [Alberta Energy, 2013]. Deposits found deeper are accessed via in-situ methods, with steam-assisted gravity drainage (SAGD) being the most commonly used in current operations. Of the oil sands produced in 2011, 51% was produced with surface mining and 49% produced by in-situ techniques. However, the remaining reserves of the Alberta oil sands that are considered recoverable by surface mining and in-situ methods are estimated at 20% and 80%, respectively [Alberta Energy, 2013].

The extracted bitumen from the oil sands is too viscous for pipeline transportation and therefore requires processing so it can be transported to refineries where it is converted into end use products such as transportation fuels. For processing of the bitumen into a less dense and viscous product, oil sands operators can either convert the oil to produce a higher quality product, commonly referred to as a synthetic crude oil (SCO), with a process known as upgrading or dilute the bitumen with lighter hydrocarbons to achieve density and viscosity requirements for pipeline transportation.

In Alberta, upgrading is used to obtain a high quality crude oil that far exceeds the minimum pipeline viscosity and density requirements. For the purpose of this research we will refer to this type of upgrading as 'full-upgrading' which is characterized by an upgraded product, hereafter referred to as a 'full-SCO', with density similar to a light or medium crude (light crudes are typically characterized by an API gravity above 30 while medium crudes have an API gravity between 21 and 30). The option to use a smaller scale upgrader, with significantly reduced capital costs, for converting the oil to a level which approaches pipeline specifications is known as 'partial-upgrading'. The option for producing a 'partial-SCO' is currently being evaluated at pilot plants and test projects with field demonstration pilots planned for operations as soon as 2016 [Roche, 2013].

Full-upgrading was used for conversion of 57% of the bitumen produced in the province in 2011 [Alberta Energy, 2013]. The two main upgrading processes/technologies used in industry are delayed coking with hydrotreating, and hydrocracking with hydrotreating. Delayed coking uses high temperature thermal-cracking of the hydrocarbons to produce shorter chain molecules. This produces more of the lighter hydrocarbons as well as a petroleum coke by-product. The light hydrocarbons are then further treated by hydrogenation processing, hydrotreating, to increase hydrogen content. Hydrocracking includes mild temperature processing of the bitumen in the presence of hydrogen to break the hydrocarbon chains and increase hydrogen content. Hydroprocessing is again used to further increase the hydrogen content of the crude. Hydrocracking with hydroprocessing does not produce as much coke as delayed coking and hydroprocessing but consumes more hydrogen.

If oil sands operations elect not to upgrade then the bitumen requires dilution with lighter hydrocarbons to effectively decrease the viscosity and density of the bitumen to a maximum allowable level for pipeline transportation. This diluted product is typically formed with the addition of approximately 25 to 30 weight percent addition of a naphtha diluent and is known as a diluted bitumen or ‘dilbit’ [Choquette-Levy, 2013]. Though naphtha is the most commonly used diluent, other hydrocarbon diluents used in industry include natural gas condensate and SCO. In the case of bitumen dilution with SCO, the product is known as a synthetic bitumen or ‘synbit’.

The primary method for transporting crudes to the refinery is by pipeline. Pipeline transportation currently accounts for the transportation of approximately 95% of Canadian produced oil and natural gas, however, growing production and limited capacity of current pipeline infrastructure has increased use of alternative transportation methods such as railway [Center for Energy, 2013]. Pipeline transportation involves inputs from many producers where the crude oils are blended together in the pipeline as they are being transported to the refineries. In the case that the oil is not refined in Alberta, the crudes are shipped long distances to refineries, commonly to refineries in the US Midwest or US Gulf Coast.

Refineries are used to convert crude oil to refined petroleum products such as gasoline, diesel, naphtha, kerosene and jet fuel. Each refinery is a unique combination of process units/technologies and configurations determined based on the properties of the crude oil types that they are converting and their desired product slate. For the purpose of this thesis, the three primary configurations modeled for the refining of crude oil are hydroskimming, medium conversion, and deep conversion. Hydroskimming conversion uses minimal hydrogen addition processing with naphtha catalytic reforming to refine light crudes, characterized with an API gravity above 30^{o}. Medium conversion is typically used on slightly heavier feedstock in comparison with hydroskimming feedstocks and uses fluid catalytic cracking and hydrogenation processing. Deep conversion refineries can convert a wide variety of crudes including heavy crude feedstocks, as characterized with an API gravity below 20^{o}, in a similar manner to delayed coking upgrading, discussed above. Due to significant variance in the process units and configurations across refineries in North America, different product slates will be produced based on the unique configurations of technologies used at each refinery. Additionally, though the configurations and technologies are best suited for specific crude properties, it is possible to process lighter crude oils with deeper conversion technologies which could be the case due to limited hydroskimming refinery capacity in North America.

1.4 Bitumen Upgrading and Dilution

The Alberta government has proposed incentives for the oil sands industry to convert bitumen, with upgrading and refining, within the province to increase the economic return through value added processing as well as creating more high paying jobs [Government of Alberta, 2007]. However, these energy systems decisions reflect international operations and markets where oil sands companies are seeking to maximize the value of their investments. Therefore, the decision to upgrade or dilute bitumen in Alberta requires weighing economic and GHG emissions impacts. Upgrading facilities are capital and operating cost intensive. Some of these costs are due to the energy intensive processing required. While dilution requires significantly less capital investment, it requires purchasing diluent throughout the life of the project and more pipeline capacity. Uncertainty in future emissions, diluent, and energy costs are important factors to consider in making decisions about these energy system pathways due to the long term energy infrastructure investments of these operations.

Upgrading technologies have played an important role in the development of Canadian oil sands with the first upgrader in Canada being an integral part of the first commercial oil sands production by the Great Canadian Oil Sands Limited in 1967 [Suncor Energy, 2013]. Since then, upgrading technologies have evolved and subsequently a number of unique processes have been developed and implemented. The upgrading technologies generally fall into two categories, carbon rejection technologies or hydrogen addition processing technologies.

Carbon rejection technologies, such as delayed coking, redistribute hydrogen amongst the various compounds in the heavy oil to produce more of the desirable lighter fractions such as diesel. Through increasing the hydrogen to carbon ratio of the lighter fractions and decreasing the hydrogen to carbon ratios of the heaviest fractions, the hydrogen redistribution separates the low hydrogen content products such as petroleum coke (referred to as coke or pet coke) or asphaltenes from the lighter materials which comprise the full-SCO product. The rejected coke can be stockpiled or used as a low cost but high emissions energy source for purposes such as electricity generation or hydrogen production. Analysis of environmental and financial performances of oil sands operations have suggested various potential markets for petroleum coke where these real-options analysis quickly become further complicated by location specific emissions policies and potential use of carbon capture and storage (CCS) systems [McKellar, 2010].

Hydrogen addition processes, such as hydrotreating, react hydrocarbons with supplied hydrogen to increase the hydrogen to carbon ratio of the crude. The hydrogen supplied during this form of processing is commonly produced from steam methane reforming that converts natural gas to hydrogen. Gasification of heavy oil products is another option that can be employed for the production of hydrogen, however, it is currently not widely adopted due to the low price of natural gas. In comparison to carbon rejection processes, hydrogen addition has the benefit of producing more of the desirable light hydrocarbons with less pet coke or asphaltenes. In the case of processes which rely on steam methane reforming for hydrogen production, the future of these hydrogen addition processes will likely be linked to price of natural gas.

CSC processing has characteristics of both carbon rejection and hydrogen addition processing. CSC upgrading technologies use ultra-dispersed catalysts to increase thermal conversion and generate hydrogen through the dissociation of water. This form of hydrogen production is unique from current steam methane reforming processes commonly employed in oil sands upgrading. For CSC upgrading, the catalyst content of the feed and hydrogen supplied from the steam is intended to produce less pet coke with comparable conversion/upgrading levels to carbon rejection processes under analogous conditions.

1.5 CSC Partial-Upgrading

Though CSC as an upgrading technology and partial-upgrading plants both have several potential advantages in comparison with current full-upgrading and dilution pathways, such as CSC generation of hydrogen from steam and lower capital costs of partial-upgrading plants compared with full-upgraders, neither have seen significant adoption in the Canadian oil sands. CSC upgrading and catalyst preparation technologies/techniques are currently being studied at a pilot plant scale at the University of Calgary to determine the applicability of this technology for integration into current operations or new facilities. These technologies have been developed and evaluated over the past ten years by the Catalysis for Bitumen Upgrading Group (CBUG) within the department of Chemical and Petroleum Engineering at the University of Calgary. A partial-upgrading pathway using the CSC upgrading technology for bitumen conversion is patented as “Systems and Methods for Catalytic Steam Cracking of Non-Asphaltene Containing Heavy Hydrocarbons” by Dr. Pereira et al. in association with Nexen Inc. in 2013 [Pereira, 2013]. The CSC partial-upgrading pathway developed in this patent is used as the basis for the emerging process evaluation of this thesis.

Pilot plant or lab-scale evaluations are small scale operations which are used to determine the performance of a technology or process before scaling up to demonstration or industrial scale operations. This study uses pilot plant evaluation to determine the characteristics of the upgraded crude oil and the process requirements for use in the subsequent LCA evaluation. However, not all industrial process requirements could be directly scaled based on the pilot plant results because the pilot plant setup does not include all required process units, such as distillation towers or amine gas treatment, and does not reflect integrated process units, extensive process optimization, or industrial energy systems. For this reason, the estimates for industrial scaling of this CSC partial-upgrading pathway rely on engineering simulation modeling and industrial process requirement data from literature.

Benefits of estimating industrial scale implementation and process requirements include calculating operational emissions impacts and estimating the capital and operating and maintenance costs associated with this emerging CSC partial-upgrader. Estimates for operational emissions impacts allow for direct comparison with existing technologies such as coking full-upgrading. Additionally, the CSC partial-upgrading process requirements can also be used to identify process unit requirements with the highest associated GHG emissions or economic impact which therefore warrant additional consideration when further developing the CSC partial-upgrading process.

1.6 LCA Evaluation

LCA is a tool used for the evaluation of environmental and economic impacts of a product or process from initially obtaining the raw material to the end use and/or disposal of any waste products [International Organization for Standardization, 2006]. LCA framework commonly uses mass and/or energy flows to account and relate environmental impacts between stages in the product or service’s life cycle. The first multi-attribute study, which has been credited as a basis for current LCA framework, was an environmental assessment by Coca Cola for the comparison for packaging materials for beverage containers in 1969 [Journey Staff, 2012]. LCA methods have been increasingly adopted due to mounting concerns around environmental impacts/issues such as climate change. The use of LCA framework has been very prevalent when assessing energy systems due to the energy intensive nature of the production phase and significant contribution to rising global GHG emissions. For example, oil sands operations and transportation products have been found to contribute approximately 15% of Canada's total GHG emissions [Bergerson, 2006].Other examples of adoption of LCA methods include Walmart's Sustainability Index and LEED building standards [Curran, 2011].

Adoption of LCA tools and methods became further established with the development of International Organizing Standards (ISO) LCA guidelines in 1997 [European Parliament, 2004]. The adoption of LCA methods and subsequent characterization of products and processes in more fields of study has allowed for the development of more complex LCA studies built upon prior literature estimates. By building upon previous literature, such as established life cycle impact databases and tools, LCA studies are able to capture upstream and downstream impacts for input and output energy or materials to air, water or ground.

Through accounting for inputs and releases from the product or process, this tool is used to account for a product's life cycle from "cradle-to-grave" or well-to-wheel (WTW) in the case of crude oil products. Previous studies to better understand the environmental impacts of oil sands operations at the University of Calgary and University of Toronto have contributed to the development of an integrated LCA model [Abella, 2012. Charpentier, 2011. Choquette-Levy, 2011]. This model, along with simulation modeling and adapting industrial process estimates for specific impacts of CSC partial-upgrading, are used for assessing WTW emissions impacts. Further economic characterization of the upgrading and dilution processes and consideration of emissions policies allows for the direct economic comparison of the oil sands pathways.

Developing the CSC partial-upgrading model as a part of the integrated LCA model allows for a consistent Well-to-Wheel (WTW) comparison with other oil sands pathways which produce a different quality of crude for pipeline transportation and refining. For example, previous studies have shown the emissions associated with transporting product from dilution and full-upgrading are very different due to the increase resistance to head flow of the denser and less viscous dilbit [Choquette-Levy, 2013]. Additionally, the GHG emissions associated with refining a fully-upgraded SCO can be less than half of the associated GHG emissions of a dilbit [Abella, 2012]. However, the emissions associated with a dilbit will also include the lower upstream emissions from dilution rather than the energy intensive processing of full-upgrading [Charpentier, 2009]. Incorporation of GHG impacts into a WTW LCA study and subsequent economic comparisons of oil sands pathways is used to inform oil sand investment options and policy development.

LCA studies can typically be broken down into four sections: goal and scope, inventory analysis, impact assessment, and interpretation and improvement. The goal of the life cycle assessment is aligned with the research questions stated, namely assessing the potential relative life cycle emissions of CSC partial-upgrading compared to current upgrading and diluents estimates. With this research question, we are defining the scope of assessment to be based on the emissions from extraction through to end use. The inventory analysis typically involves consideration of mass and energy balances of inputs and releases from a product system. The inventory analysis is extensive due to the complexity and extent of the analysis in evaluation from pilot plant upgrading trials to modeling it as part of a WTW LCA emissions model which interprets system choices between stages of the life cycle. For the purpose of this evaluation, the inventory analysis is completed through collection of data from the pilot plant evaluation described in Chapter 2, the estimation of industrial scale emissions of the partial-upgrader described in Chapter 3 and downstream inputs and outputs are considered in the LCA completed described in Chapter 4. The impact assessment of this LCA involves both environmental and economic impacts. The calculation of WTW emissions is accomplished through use of emissions factors that are related to the environmental impacts of the material and/or energy inputs and released determined in the inventory analysis. The economic impacts of these options are calculated through estimation of the industrial process capital and operational costs and the internalization of the externalities caused by emissions, related to relevant policies. Finally, the interpretation and improvement stage builds upon the inventory analysis and impact assessment to identify ways in which to further reduced impacts of the CSC partial-upgrading process as well as interpret the effects of uncertain market and policies on energy systems decisions in the future development of the oil sands. The engineering and economic concepts used for the framework of this study are intended to inform industry and policy discussions related to GHG emissions and economic impacts of these energy system pathways.

Life cycle evaluation studies are becoming increasingly prevalent in the design and enforcement of environmental policies [State of California, 2006]. Due to the complexity of the oil sands industry, a number of these studies and tools developed for estimating emissions tend to over simplify emissions estimates. For example, pipeline transportation emissions estimates from consultancy studies published on the LCA of oil sands crudes by Jacobs and TIAX dismiss the effects of varied crude densities and viscosities which more recent studies have shown to affect emissions impacts [Choquette-Levy, 2013]. Therefore, the aim of this evaluation is to transparently characterize, based on engineering concepts, the process requirements and GHG emissions which can be directly compared with emissions estimates made using the integrated LCA model and further verified with published studies. Through accounting for the inputs and outputs of the projected industrial level process requirements and incorporating them into a WTW LCA model, this thesis aims to characterize the life cycle emissions for comparison of dilution, CSC partial-upgrading and full upgrading pathways.

Cost-benefit analysis is used to address the question of "whether to invest in a CSC partial-upgrading, traditional full-upgrading or dilution pathways for future oil sands development?" These energy system decisions depend on traditional economic investment considerations, such as capital and operational costs, as well as future crude or utility prices and emissions policies. Planning for these energy systems investments becomes perpetually complicated with long-term projection of future market conditions as well as potential future climate policies for addressing environmental impacts.

Oil sands projects are currently subject to the Alberta's Specified Gas Emitters Regulation (SGER) which taxes cumulative operational GHG emissions for large-scale facilities within the province (annual GHG emissions greater than 100,000 tonnes of CO_2e/year) [Alberta Environment, 2013]. This tax imposes $15/tonne CO_2e for emissions above a baseline emissions threshold. This baseline threshold is defined by a reduction from 2007 facility operational emissions or the first year of commercial operation in the case of newer facilities (with a maximum reduction of 12%; therefore at least 88% of the facilities baseline emissions are not taxed). With oil sands pathways often involving international transportation, refining and product distribution, the SGER does not address the full life cycle impacts for GHG emissions. Contrarily, versions of a Low Carbon Fuel Standard (LCFS) in British Columbia and California use life cycle GHG impacts for assigning economic penalties or subsidies to transportation fuels [Province of British Columbia,

2013. State of California, 2006]. In order to sell fuel products to these markets the life cycle emissions of the transportation fuel must meet the defined GHG emissions threshold (referred to as a Carbon Intensity threshold by the California Air and Resource Board (CARB)). Producers that want to sell a transportation product which is above this threshold must either lower the life cycle GHG emissions of their product, blend their product with other products which are below the emissions threshold, or buy credits from producers with products that are below the emissions threshold. The possibility of an economy-wide carbon tax in Alberta, like many European countries and Australia, may further affect future energy system investment decisions related to partial-upgrading, full-upgrading and dilution pathways [European Commission, 2013. Australia Government, 2013.]. Through economic internalization of these emissions in accordance with current and future emissions, these different oil sands pathways can be directly compared for future project investment decisions.

1.7 Summary and Contributions

A LCA framework for the assessment of emerging technologies contributes to the growing body of LCA literature for energy systems decisions and the oil sands industry [Jungbluth, 2004. Bergerson, 2012. Brandt, 2012]. This thesis develops a framework for assessing an energy systems decision of an emerging pathway that allows for direct comparison with industrially operating systems. The development of a life cycle emissions modeling and cost-benefit analysis allows for a direct comparison of GHG emissions and economic trade-offs involved with CSC partial-upgrading, full-upgrading and dilution pathways.

Chapter 2 focuses on a thorough pilot plant evaluation of the CSC partial-upgrading process to determine the upgrading performance and process requirements. Through performing this pilot plant evaluation, the CSC partially-upgraded oil products and produced gas are characterized and material balances for hydrocarbon streams and process requirement, such as catalysts and steam requirements, are determined to inform industrial scale implementation and modeling.

Chapter 3 details the estimates for industrial scale process requirements for all process units involved with the CSC partial-upgrading using pilot plant data, modeling simulations and industrial estimates. Use of Aspen HYSYS® modeling systems and literature correlations, such as from Gary and Handwerk, for process unit requirements and associated costs are used to determine the plant process requirements, and capital and operating and maintenance costs for a prospective 100,000 barrel per day facility [Gary, 2001]. GHG emissions for the CSC partial-upgrading plant operation are determined based on the calculated process requirements and literature emissions intensity factors which relates process requirements to the activates involved with the production of that resource, such as relating the power requirements to the Alberta grid emissions intensity statistics from Environment Canada [Environment Canada, 2010]. Additionally, this chapter explores and identifies the areas of most significant emissions impacts for the CSC partial-upgrading process as to better direct research efforts for the development of a less GHG intensive process.

Chapter 4 asses' life cycle GHG emissions through WTW comparison of the CSC partial-upgrading and full-upgrading and dilution pathways and develops and explores the effects of proposed carbon-pricing policies through cost-benefit analysis of the pathway options. Emissions estimates are achieved through modeling of CSC partial-upgrading as a part of in an integrated LCA model that accounts for oil sands operations from extraction through to end use. Modeling of the CSC partial-upgrader for WTW analysis relies on crude properties, determined in Chapter 2, and process unit level modeling of the CSC-partial upgrading, determined in Chapter 3. Use of this integrated LCA model allows for direct comparison with previously established estimates for full-upgrading and dilution options in the integrated LCA model [Abella, 2012. Charpentier, 2011. Choquette-Levy, 2011]. A case study with projected pathway costs, crude prices, income taxes and royalties is used to inform GHG and economic trade-offs involved with future oil sand developments. A sensitivity analysis of key economic parameters is used to directly compare the profitability of CSC partial-upgrading pathway with uncertain future market condition and emissions regimes.

Chapter 5 concludes environmental policy conditions and future market prices for which the CSC partial-upgrading pathway would be competitive with current oil sands pathways. This chapter also addresses the applicability of this type of LCA framework for the evaluation of other emerging technologies and proposes further research which can build upon insights gained from this study.

The contributions made by this thesis are methodological for the LCA framework used for the evaluation of emerging technologies and identification of the environmental and economic trade-offs of a CSC partial-upgrader in comparison with current oil sands pathways. Through identification of the potential GHG emissions of CSC partial-upgrading when scaled industrially, this thesis identifies areas of most significant environmental impact to direct future research and development efforts. Additionally, this LCA of an emerging partial-upgrading pathway contributes to a growing database of LCA literature that can be used to benchmark a potential partial-upgrading pathway with current literature estimates for full-upgrading and dilution to better inform energy system investment decisions and policy development.

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2.0 Pilot Plant Evaluation of Catalytic Steam Cracking (CSC) Partial-Upgrading

Catalytic steam cracking conversion of heavy hydrocarbons for the purpose of partial-upgrading is currently under investigation at a pilot plant scale at the University of Calgary. This pilot plant evaluation is intended to better inform the industrial applicability of CSC partial-upgrading, developed by Pereira et al. [Pereira, 2013]. The purpose of this pilot plant evaluation is to establish critical operational parameters for upgrading of vacuum gas oil (VGO) and de-asphalted oil (DAO) crude oil fractions and to characterize the CSC partial-SCOs. Due to pilot plant limitations in terms of processing capacity and operation, the evaluation of these systems differs from industrial operation because this processing plant is unable to perform all the necessary processing of an industrial facility, such as distillation and off-gas treatment. The pilot plant also cannot achieve on-stream processing between process units, such as the catalyst preparation and the CSC upgrader process units.

The purpose of this CSC pilot plant evaluation is to characterize the CSC partial-upgrading process and products to inform the industrial process modeling as well as the life cycle emissions and cost-benefit analysis. This evaluation is used to better understand the CSC partial-upgrading process requirements and the quality of the partially upgraded product (referred to as a partial-SCO). This pilot plant study focuses on the catalyst preparation, CSC upgrading, and the partial-SCO formulation for CSC partial-upgrading. The upgraded products used in the formulation of the partial-SCO are selected based on a comparison of the products upgraded under different conditions, such as reaction temperature and space velocity. The qualities of upgraded products are compared with respect to conversion level, viscosity, density, P-Value, Micro Carbon Residue (MCR), and off-gas production. Additional processing or plant operations, such as separation processes or amine gas treatment, are outsourced/externally performed for the purpose of this pilot plant study but are later accounted for in modeling of industrial scale emissions and economic impacts. The pilot plant determines process parameters and requirements, such as steam or catalyst concentration, used for evaluation of this CSC partial-upgrading process in Chapter 3. Thoroughly analyzed crude properties, such as bitumen conversion levels and upgrading product composition, are used in the characterization of these Partial-SCOs in the comparative LCA in Chapter 4.

2.1 Introduction of CSC for Partial-Upgrading

Catalytic steam cracking can be broadly defined by the process of oil conversion through thermal cracking and hydrogen addition from catalytic steam dissociation reactions carried out concurrently. Though CSC can employ different catalysts with unique functions, we can broadly define CSC through two principal reactions; thermal cracking and reforming [Trujillo, 2008].

Thermal cracking reactions effectively break long chained carbon-carbon bonds to produce shorter chained or '*lighter'* hydrocarbons in the presence of heat [Ballard, 1992]. Thermal cracking reactions are commonly employed in upgrading processes targeting conversion of *'heavy'* hydrocarbon fractions, such as delayed coking.

Reforming is a chemical reaction in which the hydrocarbons structures are re-arranged. In the case of CSC, this selective catalytic steam reforming reaction uses two types of catalysts to dissociate hydrogen from steam and to promote the addition of hydrogen to the free radicals of the hydrocarbon chains [Duprez, 1992]. This method for producing hydrogen is unique from most hydrogen-addition upgrading processing, referred to as 'hydroprocessing'. This method is different from traditional 'hydroprocessing' in that the hydrogen is produced from the steam supplied during the upgrading reaction process as opposed to being produced from a hydrocarbon fuel. Hydrotreating, a form of 'hydroprocessing', commonly uses steam methane reforming as a precursor step for producing the hydrogen required during the upgrading reaction.

Two categories of catalysts are used in the reforming process. Transition metals are used for the hydrogenation of steam [Trujillo, 2008]. Alkaline metals are used for promotion of hydrogen saturation [Trujillo, 2008]. Hydrogen saturation reduces undesirable condensation reactions which result in the formation of asphaltenes during crude oil upgrading and refining.

For CSC, the dispersion and particle size of these unsupported catalysts significantly influence the effectiveness of the catalysts. Better dispersion and smaller particle size can lead to higher chances of more efficient contact between the hydrocarbons and the catalyst's active site [Galarraga, 2011].

The following are reaction mechanisms that define the primary processes of CSC Upgrading [Pereira, 2013].

1) $R - R'_n \rightarrow R\cdot + R'_n\cdot$ Thermal Cracking

2) $H_2O \underset{cat}{\longrightarrow} H\cdot + OH\cdot$ Steam Dissociation

3) $R\cdot + R'_n\cdot + 2H\cdot \underset{cat}{\longrightarrow} R - H + R'_n - H$ Hydrogen Saturation

4) $R'_n\cdot + 2OH\cdot \underset{cat}{\longrightarrow} R'_{n-1} + CO_2 + H_2$ Oxidation/Reforming

5) $R\cdot + R'_n\cdot \rightarrow R - R'_n$ Condensation

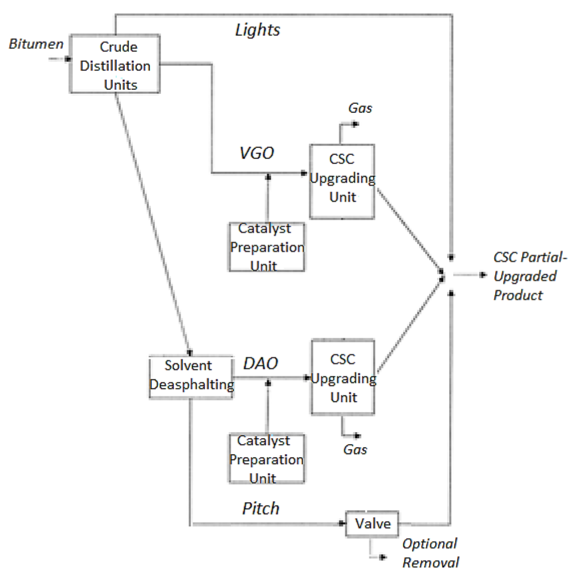
Catalytic steam cracking has been investigated through projects such as the Aquaconversion™ developed by Petróleos de Venezuela (PDVSA) [Marzin, 1998. Pereira, 1998. Solari, 2000. Pereira, 2000. Pereira, 2001]. This technology was developed to upgrade heavy oils from the Orinoco Belt in Venezuela. Though published papers suggest this technology can achieve greater conversion and viscosity reduction compared with visbreaking processes (for non-catalytic thermal cracking of the residue oil fractions) [Solari, 2000]; there is little published information available regarding this technology and process. The heavy oils found in the Orinoco Belt and those of the Alberta Oil Sands are similar and thus upgrading technologies used for Venezuela heavy oil could be considered for application in the Oil Sands Industry.

This study uses life cycle emissions and cost-benefit framework for evaluating a partial-upgrading pathway invented by Dr. Pereira and the Catalyst for Bitumen Upgrading Group at the University of Calgary [Pereira, 2013]. CSC partial-upgrading, patented by Nexen Inc., enables the upgrading of heavy hydrocarbons, such as bitumen, to a hydrocarbon product which is capable of being transported through pipelines [Pereira, 2013]. This patent describes a method for CSC partial-upgrading which is being studied and modeled to determine applicability for bitumen upgrading.

CSC partial-upgrading targets conversion of middle fractions of the oil (as defined in terms of boiling point characteristics) without extensive processing of the heaviest or lightest crude fractions. This is in contrast with conventional upgrading, such as delayed coking, which targets the conversion of the heaviest fraction through energy intensive processing. By omitting conversion of the heaviest fraction, CSC partial-upgrading reduces the number of process units required in upgrading but it also produces a lower quality product in comparison with full-upgrading. The patent suggests this form of CSC partial-upgrading could upgrade Athabasca bitumen to an API gravity equal to or greater than 15^{o} and a viscosity equal to or less than 350 cP at 25^{o}C, in the case that the pitch fraction is removed during CSC partial-upgrading [Pereira, 2013].

The process of CSC partial-upgrading, in one of its proposed forms, is comprised of the following steps: 1) separation of heavy hydrocarbon mixture with a topping/atmospheric distillation tower to distill a 'light' fraction, and a vacuum distillation tower to distill a vacuum gas oil (VGO) fraction; 2) separation of vacuum residue fraction with a solvent de-asphalting (SDA) process to obtain de-asphalted oil (DAO) and an asphaltene rich pitch fraction; 3) catalyst preparation and addition to VGO and DAO crude fractions that are then sent to CSC upgrading units; 4) separation of effluent streams into a gas and liquid; 5) mixing of the upgraded liquids (VGO and DAO) with light and pitch fractions <u>or</u> mixing of the upgraded liquid with light fractions while pitch is not included in the CSC partial-SCO product. A diagram of CSC partial-upgrading, adapted from the CSC patent, can be seen below in Figure 2.1.

Figure 2.1 CSC partial-upgrading [adapted from Pereira, 2013]



The CSC patent for partial-upgrading indicates the use of catalysts, with particle sizes less than 250 nm, comprised of one or a combination of, rare earth oxides, group IV metals, alkali metals, nickel oxide, cobalt oxides, and molybdenum oxide. These particles can be structured as part of a fixed bed catalyst or used as a dispersion. The latter is obtained through high energy mixing that effectively decomposes the metal salt precursors. In this study, Ni and K catalyst are prepared as ultra-dispersions in the VGO and DAO crude oil fractions.

For CSC partial-upgrading, the bitumen is fractionated and separated into light, VGO, DAO and pitch fractions. The VGO fraction, characterized by boiling points between 250^{o}C and 545^{o}C, is the overhead distillate product from the vacuum distillation tower. The DAO, characterized as the de-asphalted product from 545^{o}C^{+} (boiling points greater than 545^{o}C) residue, is separated by the SDA unit.

The separated fractions which do not undergo upgrading are the overhead distillate product from the topper/atmospheric, referred to as 'lights', and the asphaltene-rich SDA product, referred to as 'pitch'. The lights fraction, characterized by initial boiling points (IBP) below 250^{o}C, is re-incorporated into the partial-SCO. The pitch fraction is the heavy SDA product, sometimes referred to as asphaltenes, which can either be mixed into the partial-SCO or it can be removed from the CSC partial-upgrading process after it is separated with SDA. For the purpose of this evaluation, it is assumed that the entire amount of pitch will either be re-incorporated into the CSC partial-upgraded product or it is completely removed and stockpiled or used for other purposes. Instead of incorporating the pitch into the CSC partial-SCO it could be used as an energy source, in the case of remote upgrading operation where energy supplies are too expensive or unreliable, or sold for use in other markets, such as for power or cement industries. However, the option of stockpiling pitch, burning it for energy, gasifying it for hydrogen, or selling it to other markets is dependent on market value for pitch and cost of diluent as well as emissions policies, and how the by-products such as pitch are assessed. This decision has important effects on crude properties, required diluent, and life cycle emissions and the overall economic value. These impacts are explored in Chapter 4.

2.2 Method for CSC Pilot Plant Evaluation

The pilot plant evaluation is used to assess and identify representative process conditions and characterize the product CSC Partial-SCOs. The experimental plan for this pilot plant evaluation is influenced by previously completed pilot plant studies performed at the University of Calgary [Trujillo, 2008. Pereira, 2013. Nexen, 2012]. Previous studies were used for developing the CSC upgrading process unit through process unit design and for selecting catalysts, catalyst preparation methods, and CSC upgrading processing conditions [Trujillo, 2008]. Additional studies performed confidentially for Nexen Inc. identified process condition and the resulting quality of the CSC partial-SCOs [Pereira, 2013]. However, the specific operational results from the Nexen Inc. pilot plant study, such as the upgraded quality of the VGO and DAO products, as well as a full characterization of the CSC partial-SCOs are only included in a confidential report and therefore cannot be included in this thesis.

This pilot plant study evaluates various DAO and VGO upgrading conditions to select representative CSC upgraded DAO and VGO products for formulation as part of the CSC partial-SCOs. This pilot plant study uses previously developed process unit design/set-up for the analysis of CSC partial-upgrading [Trujillo, 2008]. This study uses processing conditions, such as catalyst and water concentrations, reaction temperature, pressure, and space velocity (LHVS), based on conditions from previous CSC upgrading studies which were found to produce desirable conversion levels with minimal production of undesirable asphaltenes [Trujillo, 2008. Nexen, 2012]. Evaluation of steam-thermal VGO and DAO upgrading is used to demonstrate the effect of the catalysts in CSC upgrading as the feedstock prepared with catalysts should achieve a higher level of conversion with similar or less production of undesirable asphaltenes. Table 2.1, below, summarizes the processing conditions selected for this study.

Table 2.1 Experimental plan for pilot plant upgrading conditions [selected based on studies by Trujillo, 2008. Nexen, 2012]

	Temperature	Pressure	LHVS	Water	Nickel	Potassium
Steam-Thermal VGO	430 ^oC	400 psi	2 hr^{-1}	5 wt. %	-	-
CSC VGO	440 ^oC	400 psi	2 hr^{-1}	4 wt. %	300 ppm	500 ppm
CSC VGO	445 ^oC	400 psi	2 hr^{-1}	4 wt. %	300 ppm	500 ppm
CSC VGO	440 ^oC	400 psi	1.7 hr^{-1}	5 wt. %	300 ppm	500 ppm
CSC VGO	435 ^oC	400 psi	1.7 hr^{-1}	5 wt. %	300 ppm	500 ppm
Steam-Thermal DAO	425 ^oC	300 psi	3 hr^{-1}	4 wt. %	-	-
CSC DAO	440 ^oC	300 psi	3 hr^{-1}	4 wt. %	300 ppm	500 ppm
CSC DAO	435 ^oC	300 psi	3 hr^{-1}	4 wt. %	300 ppm	500 ppm
CSC DAO	435 ^oC	300 psi	3.2 hr^{-1}	4 wt. %	300 ppm	500 ppm
CSC DAO	440 ^oC	300 psi	3.2 hr^{-1}	4 wt. %	300 ppm	500 ppm

This pilot plant study uses a catalyst preparation process unit for preparation of the feedstock with an ultra-dispersed catalyst through high energy mixing. This form of catalyst preparation is in contrast to the emulsion preparation method, employed for previous trials [Trujillo, 2008]. Though this evaluation is not intended to conclusively determine the effects of the ultra-dispersed catalyst preparation in comparison with the emulsion preparation, it is expected that ultra-dispersed catalyst preparation will improve catalyst effects, such as reduced catalyst deactivation, from improved dispersion and increased surface area compared with emulsion catalysts preparation. Improved catalyst preparation should allow for CSC upgrading with ultra-dispersed catalysts to reach higher reaction temperatures and conversion rates with similar asphaltene stability results compared with CSC upgrading using emulsion catalysts preparation.

The crude feedstocks used for this evaluation is light (characterized by boiling points below 250^{o}C) and VGO fractions distilled from Athabasca Bitumen provided by Nexen Inc., DAO fraction provided by Nexen Inc. and the pitch produced by a solvent de-asphalting process performed by investigators under the supervisor of Dr. Pedro Pereira. The previous CSC studies [Trujillo, 2008. Nexen, 2012] were performed using a different Athabasca Bitumen sample as feedstock.

The pilot plant assessment is completed through preparation procedures and pilot plant operation. The pilot plant preparation procedures include setup and maintenance of the CSC upgrader process unit and distillation and fractionation of the crude oil. Pilot plant operations included feedstock preparation with catalysts, CSC upgrading and formulation of the partial-SCO products. Thorough product and process analysis is completed through characterization of density, viscosity, produced gas composition, hydrocarbon boiling point curves, stability/fouling tendencies, micro carbon residue content, catalyst particle size, metal content, water content, and carbon, hydrogen, nitrogen and sulphur elemental composition. This evaluation is completed at the University of Calgary pilot plant by this MSc candidate, unless otherwise stated, and the assistance of fellow researchers for process unit operations or product analysis is stated in the Sections 2.3 and 2.4.

2.3 Pilot Plant Preparation Procedures

2.3.1 CSC Upgrader Process Unit Maintenance and Updating

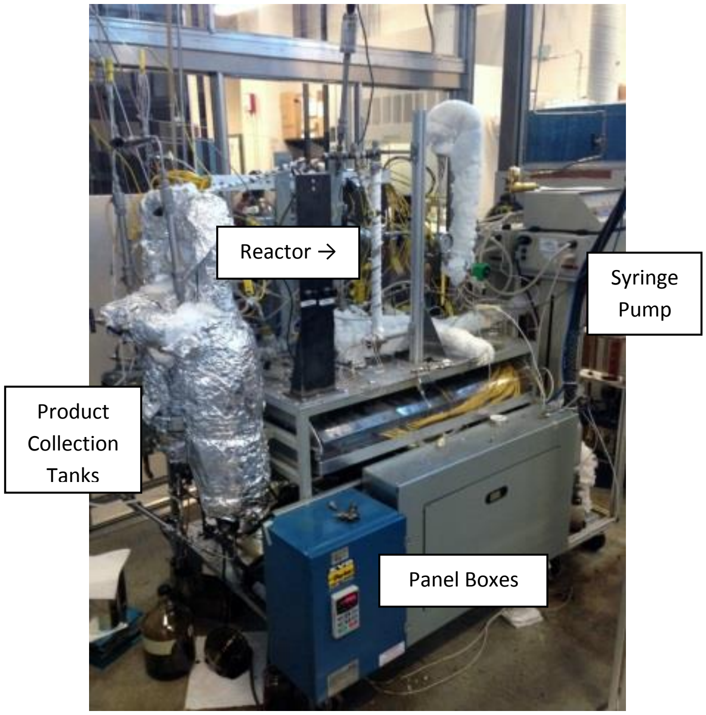
This CSC upgrader process unit requires general maintenance and updating before use in this pilot plant study. This maintenance is required to ensure that the upgrader unit is not contaminated from use with any other previous studies and that all of the controls, such as temperature and pressure, operate as intended for pilot plant trials. General maintenance and updating is described below.

New process lines are installed to minimize the possibility of undesirable effects from contaminates, such as deposits or catalysts. In the process of updating lines some modifications, such as the addition of flow valves, are incorporated to improve ease of use but these modifications are not expected to affect the operation of the process unit.

Heating tapes and thermocouples have a limited lifespan and therefore require periodic replacement. These heating tapes and thermocouples are replaced in the same configuration to be consistent with previous pilot plant studies.

Once the process lines, heating tape and thermocouples are installed the thermocouples and heating tapes are tested and pressure testing is completed. The CSC upgrader process unit is then insulated to ensure more stable control of temperature settings through minimizing heat loss. Figure 2.2 shows the CSC upgrader process unit after the insulation is installed. The two product collecting tanks can be seen on the left. The reactor, partly covered with heating tapes, is the vertical pipe seen in the middle. The Teledyne ISCO™ syringe pump, for pumping the crude feedstocks from tanks which are out of view, can be seen on the right. The interphase and transduction modules are contained in the panel boxes seen at the bottom. This unit is controlled and monitored with Labview™ process control software. This CSC upgrader process unit set-up allows for computer monitoring and recoding of temperature and pressure as well as allowing control over the heating tapes through Labview™. This CSC upgrader process unit set-up also requires manual operation and control over pumps and pressure gauges used for setting crude and water flow rates and controlling the pressure in the reactor and off-gas line.

Figure 2.2. Pilot plant upgrader process unit



2.3.2 Feedstock Fractionation and Separation

The first two steps in the upgrading process involve fractionation and separation of the feedstock. Due to an absence of distillation equipment in-house, the fractionation of the raw bitumen is outsourced to Core Laboratories. The bitumen sample is fractionated by boiling point specification in accordance with the CSC partial-upgrading process seen in Figure 2.1.

The crude oil fractions, obtained from Core laboratories, are light hydrocarbons with boiling points below 250^{o}C, a VGO fraction with boiling points between 250^{o}C and 514^{o}C and a vacuum residue with boiling points above 514^{o}C. The relative weight percentage of the lights, VGO and residue fraction are 6.7%, 38.8% and 54.5%, respectively.

The DAO feedstock used in the pilot plant testing is provided by Nexen Inc. This feedstock is from a SDA processed vacuum residue fraction. Upon boiling point characterization of this feedstock, it is determined that this DAO has an initial boiling point (IBP) of approximately 545^{o}C. Further discussion regarding this boiling point characterization and assumptions made for the crude oil fraction missing, between the final boiling point of the VGO fraction from Core Laboratories (514^{o}C) and the initial boiling point of the DAO fraction provided by Nexen (545^{o}C), can be found in Section 2.5, Discussion.

The pitch is supplied from an in-house SDA unit processing by investigator Francisco Da Silva. This in-house SDA processing is performed using the vacuum residue fraction from the Core Laboratories fractionation of Athabasca Bitumen (514^{o}C^{+}). This SDA process mixes the residue with n-pentane solvent at a 10:1 volume of solvent to oil ratio. This results in the separation of the DAO fraction from the asphaltene-rich pitch fraction at 150^{o}C and 500 pound per square inch gauge (psig). The DAO fraction from this in-house processing is not used for the pilot plant trials due to the limited production volume of this SDA unit in comparison with the upgrading feedstock requirements. For the purpose of this pilot plant evaluation, a weight percent of 12.5% of the original bitumen is assumed for the pitch fraction (personal communication with Lante Carbognani). The SDA unit operation and performance is currently under investigation by researchers under the supervisor of Dr. Pedro Pereira and further details regarding the SDA processing cannot be divulged in this thesis.

2.4 Pilot Plant Operations

2.4.1 Feedstock Preparation with Catalyst

The preparation of the VGO and DAO feedstocks with ultra-dispersed catalysts is performed with the catalytic preparation unit. The catalyst preparation process unit has been previously demonstrated at the University of Calgary through a variety of pilot plant studies; from process unit design and set-up to detailed catalyst particle behavior studies and catalytic upgrading evaluations [Loria Monlina, 2009. Galarraga, 2011. Peluso, 2011]. This preparation process unit is currently a stand-alone unit which is used to effectively disperse the catalyst into a feedstock in a batch process. This is in contrast to an in-stream catalyst preparation process unit which would be used to prepare the crude feedstock with catalyst during the upgrading process. The differences between the operation of this pilot plant catalyst preparation process unit and a perspective industrial scale catalyst preparation process unit are discussed further in Chapter 3. Further detail regarding the design and operation of the catalyst preparation process unit for the ultra-dispersed catalysts can be found in research completed at the University of Calgary [Galarraga, 2011. Peluso, 2011]. Andrew Carss and Lorena Bernal assisted with the operation of the catalyst preparation process unit.

The catalyst preparation process unit, in the current design, is limited by internal pumps capabilities for preparation of feedstock with a viscosity below 500 centipoise (cP) at room temperature. Due to this viscosity limitation, a dilution of the DAO sample is required prior to operation of the catalyst preparation process unit. This dilution is accomplished through mixing of DAO with 25 wt.% gasoline under pressure of 200 psi and a temperature of 100^{o}C. The CSC upgrader unit was used to mix gasoline with preheated DAO by using the two independently syringe pumps for the gasoline and DAO feedstocks, respectively. Discussion regarding the setup and operation of the CSC upgrader unit can be found later in this section. The VGO does not require dilution as the feedstock has a viscosity below the threshold requirement for the catalyst preparation process unit.

The VGO and DAO are prepared with nickel and potassium catalysts derived from nickel acetate and potassium hydroxide. The targeted amount of catalyst to be added to the feedstock during the catalyst preparation, as defined in confidential research for Nexen Inc., is 300 ppm nickel and 500 ppm potassium [Nexen, 2012] (atomic ratio of Nickel and Potassium approaching 0.5). Prior to the operation of the catalyst preparation process unit, these salts are dissolved in water to desired concentrations. The required reaction temperature for the catalysts preparation unit, defined in terms of the salt decomposition temperature, were previously determined using of Thermo Gravimetric Analysis (TGA) techniques for the Nexen Inc. confidential report [Nexen, 2012]. The maximum operational temperature for catalyst preparation is selected based on the catalyst preparation process unit space time in which the catalyst precursors are exposed to the maximum temperature during mixing with the crude oil feedstock. The current design of the catalyst preparation process unit results in a space time of 2 minutes. In the case of this study, a maximum temperature of 380^{o}C is used for the catalyst preparation with VGO and DAO feedstocks.

After the feedstock and catalyst are mixed in the catalyst preparation process unit, the products from the catalysts preparation unit are cooled and separated. The VGO with catalyst is separated from the water used to dissolve the metal salts by a 250 cubic centimetre (cc) separator functioning at 30 psi and 150^{o}C. Due to the use of gasoline as a diluent for the DAO feedstock, the 250 cc separator removed the gasoline diluent and water as vapour when the product temperature is lowered to 220^{o}C.

The concentration and particle size of the catalyst dispersion is determined using metal content analysis, particle size analysis techniques. Karl Fischer water content analysis technique is used to measure the separation of the water used for preparation of the salt.

Metal content analysis

The metal content added through catalyst preparation is calculated using microwave accelerated reaction systems® (MARS®) and inductively coupled plasma (ICP). MARS® is used to heat the sample at elevated pressures to facilitate rapid digestion or dissolving of the sample using microwave energy to prepare the samples for ICP. The metal content of the prepared samples are measured using ICP atomic emission spectroscopy (ICP-AES), as performed with Thermno Scientific - IRIS Intrepid II XDL®. The metal content used for feedstock preparation far exceeds the method detection limit of the instrument. The metal content analysis for the samples was performed by Andrew Carss.

Particle size analysis

The effectiveness of the catalyst preparation process unit is also determined through dynamic light scattering (DLS) techniques that determine particle size. Malvern Instruments Ltd's Zetsasizer Nano® is used to measure the particle size of the suspended catalyst. The measurement range of this detection instrument is from 3.8 nm to 100 microns. This instrument is used to measure the particle size of the catalysts in the VGO samples but light scatter techniques are not able to be used to determine particle size in the DAO samples due to increased density and reflective index of the crude oil medium. The particle size analysis for VGO samples was performed with the assistance of Andrew Carss.

Water Content Analysis – Karl Fischer Titration

The water content of the feedstock prepared with the catalyst preparation process unit is determined using Karl Fischer titration. This is accomplished using Mettler Toledo DL-32 Karl Fischer Titration equipment®. The detection limit of this instrument is 10 µg. This analysis is required to ensure the water mass balances from the CSC upgrading runs are reflective of both the steam supplied during the reaction and the water content of the feedstock. Additionally, this analysis confirms the effective separation of the catalyst preparation process unit products; the crude feedstock prepared with ultra-dispersed catalyst from the water used to prepare the catalyst precursors solution. These analyses found the catalyst preparation has nearly complete separation of water. In the case that some water content is left, the upgrading trial supplied steam can be reduced to ensure that the water content in the catalyst prepared feedstock and the supplied steam meet the targeted reaction steam concentration.

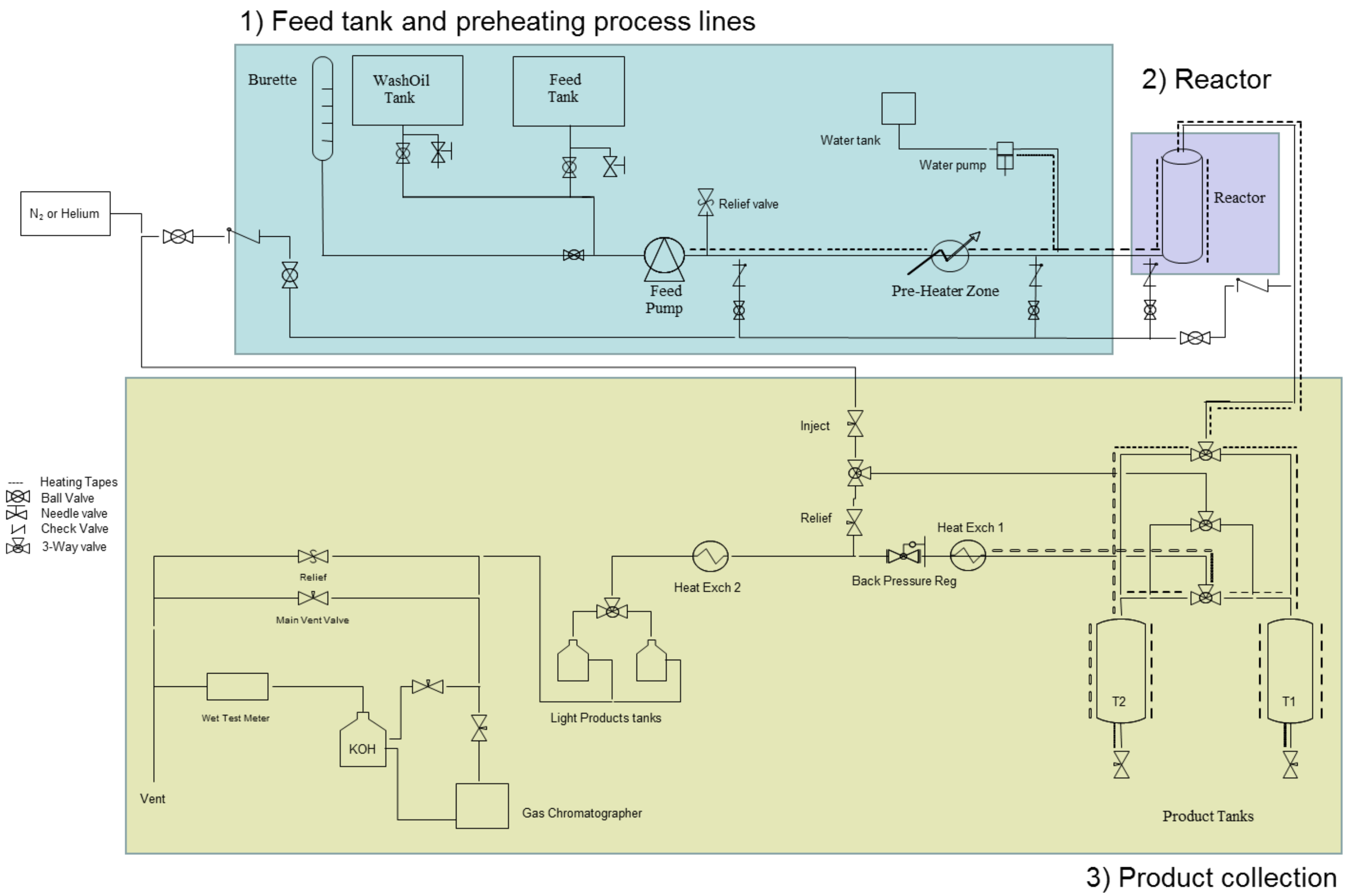
2.4.2 Catalyst Preparation Results

Catalyst preparation is evaluated with use of metal content, particle size and water content analysis techniques. The metal content analysis found the average Nickel and Potassium content added to the feedstock during catalyst preparation to be 181 and 387 ppm for the VGO sample and 366 and 574 ppm for the DAO samples. The particle size analysis of the VGO sample found an average metal catalyst particle size of 92 nm. Water content analysis confirmed the effective separation of water and the crude oil with analysis findings of negligible concentrations of water in the crude oil samples.

2.4.3 Pilot Plant Upgrading Runs

In accordance with the experimental plan, presented in Table 2.1, the upgrading of the VGO and DAO crude oil feedstocks is accomplished in a batch process using the pilot plant CSC upgrading process unit (seen in Figure 2.3). The pilot plant upgraded VGO and DAO products are compared with respect to crude characteristics such as conversion rate and Micro Carbon Residue content, described later in this section, to select upgraded VGO and DAO products that are representative of a highly upgraded product with limited formation of undesirable asphaltenes. The selected upgraded VGO and DAO products are then used in the formulation of CSC partial-SCOs with the unprocessed light and pitch material. Gustavo Trujillo assisted with the operation of the pilot plant CSC upgrading process unit.

Figure 2.3 Schematic of the CSC upgrader process unit [adapted from Trujillo, 2008]



The pilot plant CSC upgrader is a bench scale process unit for the purpose of experimental batch processing of heavy oil feedstocks. This pilot plant setup includes numerous temperature and pressure controls that operate with computer based acquisition and control systems in real time, pump controllers as well as manually operated pressure valves and multi-port valves. The computer based acquisition and control system is programed and run using Labview™ software. The operation of the upgrader unit can be broken down into 1) a feed tank and preheating process lines 2) a reactor, 3) and product collection. A schematic of the CSC upgrader process unit, adapted from [Trujillo, 2008], can be found in Figure 2.3.

The feed tank and preheater zone are comprised of a crude oil feed tank, a feed pump that enables continuous operation and heating tapes connected to the control system. The feed tank capacity is 10 L and the temperature in the feed tank can be controlled, up to 140^{o}C, to ensure the viscosity of the feedstock is below 400 cP and therefore will not damage the feed pumps. The feed pumps, high-pressure syringe ISCO pump from Teledyne, have a flow range of 0.001-138 cc per minute and maximum discharge pressure of 3,750 psig. The preheater zone also includes a water tank, water pump and water preheating zone. The steam from the preheated water and the preheated crude feedstock streams are combined before the reactor.

The reactor is a tubular up-flow reactor that enables co-current flow during the CSC upgrading process. For the purpose of this pilot plant study, the volume capacity of the reactor is 103 cc. This reactor is sized according to the desired spatial velocities and operation flow rate conditions from the experimental plan (Table 2.1). The spatial velocity, defined by the ratio of the volumetric flow rate to the volume of the reactor, is a critical factor for the upgrading process as it refers to the amount of time the crude oil is exposed to critical reaction temperatures. The temperature in the reactor zone is manually controlled by using multiple, independently controlled, heating tapes to achieve the desired reaction temperature through internally monitoring with a thermocouple probe that runs the length of the reactor. The reaction temperature during reaction typically fluctuated within approximately 2^{o}C and the average temperatures, as well as constant spatial velocities and steam concentration, are consistent with the experimental plan.

The product collection, after the feedstock passes through the reactor, is accomplished with two hot separator tanks, two cold separator vessels and a back pressure valve. The first hot separator is used to collect the product once the desired reaction temperature is achieved and stabilized. The second hot separator collects the product produced during start up, stabilization and cool down periods. The hot separator tanks are 2250 cc capacity double ended cylinders which are connected with the process line through a 3-way valve. The products collected during these periods are discarded and only the products collected during the period when the first hot separator is used are assumed to be representative of the upgrading process. A back pressure regulator valve is essential to regulate the pressure during the upgrading trials from the produced vapors and ensure a safe operating pressure in the product tanks. These vapours, consisting of a mixture of liquids and non-condensable vapours at atmospheric pressure, are passed to cold separators to collect the liquid products. The condensable liquids are collected with 250 cc capacity plastic containers. The condensable liquids collected while the first hot separator is in use are mixed with the product from the first hot separator and is representative of the upgraded liquid product. Non-condensable vapours are passed through a gas chromatograph (GC) and a gas flow meter for analysis prior to being passed through a sodium hydroxide solution to ensure the removal of any hydrogen sulphide produced during upgrading. The gas flow and composition during the period when the first hot separator is in use are required for the mass balance and represent an operational off-gas stream from the CSC upgrading process unit.

The experimental plan for this pilot plant study, as shown in Table 2.1, involves steam-thermal and CSC upgrading of VGO and DAO. Steam-thermal upgrading of VGO and DAO feedstock without catalyst is completed prior to CSC upgrading of the feedstocks prepared with ultra-dispersed catalysts to ensure that the Steam-thermal upgrading results would not be affected by any catalyst contaminants that could remain in the CSC upgrader process unit between operations. Purging of all liquids and cleaning of the upgrader unit with virgin feedstock is also conducted between operations in an effort to limit possible contamination.

A mass balance (MB) is completed to ensure that all of the products are accounted for in the upgrading process. A mass balance which results in the same mass of products as mass of feedstock ensures that undesirable processes, due to retention or leaks of the crude from the upgrader unit or improper pump operations, are not affecting results. A hydrocarbon mass balance is calculated based on the feed rate, mass of products collected in the hot and cold separators as well as based on the carbon content and flow rate of the produced gas. For this evaluation, only upgrading runs which has hydrocarbon mass balances within 2% of closing (100%) are considered for selection as representable products and condition for CSC partial-upgrading.

The products from the CSC upgrading are liquid products, which become part of the CSC partial-upgrading products, and the off-gases, which for pilot plant experiments are measured for mass flow and compositional analyzed prior to being sent to the fume hood. This is in contrast to industrial operation where the off-gases could be used in place of fuel requirements for plant operation or flared. The quantity and composition of off-gases are determined with online gas flow meters and gas chromatographers, respectively. The quantity and composition of liquid products are determined using simulated distillation and conversion calculations as well as micro carbon residue, P-value, viscosity and density testing. All of these testing methods are briefly described below. All of these analysis methods used to characterize the liquid and gas hydrocarbons are briefly described below.

Gas Chromatography

The gas produced during upgrading runs is analysed online (directly connected to the upgrader unit off-gas lines) by a SRI multiple gas analyser®. This GC analysis is used to determine concentrations of hydrogen, hydrogen sulfide, carbon dioxide and various light hydrocarbons from methane to pentanes. The GC employed in this analysis has a detection range from 250 ppm for the thermo conductivity detector and 5 ppm for the flame ionization detector. This GC was previously calibrated for a mixture of hydrocarbon gases by Gustavo Trujillo.

This GC is used to analyse the product gases at multiple time periods during the upgrading run. Results from the GC analysis, seen in Appendix E, and the results from the gas flow meter are used in the hydrocarbon mass balances seen in Tables 2.2 and 2.3.

Simulated Distillation and Conversion

Simulated distillation, or SimDist, is a GC technique which characterizes the liquid oil sample based on separating hydrocarbon components by their boiling temperatures. By comparing the sample with known calibration mixtures, the SimDist is able to distinguish components of the heated sample based on elution time to produce simulated distillation curve which characterizes the crude oil components with respect to boiling point properties. SimDist is being used in place of true boiling point (TPB) distillation which is commonly used in industry but is very time consuming and requires larger sample sizes than cannot be produced at the pilot plant scale [Vilalanti, 2010]. Though TBP characterization would ensure more accurate characterization of the sample, it is not feasible in the scope of this project due to time and cost restraints. SimDist analysis was performed by Josune Carbognani and Lorena Bernal.

A conversion rate is an indicator used to understand the level of upgrading through calculating the relative amount of lighter hydrocarbons in comparison to the feedstock. It can be calculated for the upgrading based on results from the SimDist curves and the mass balance for liquid and gas products. This conversion rate is defined by the relative change in the weight percent of the feedstock and upgraded sample at a defined temperature in the middle of the boiling point curve. For this study, the conversion rate is calculated as the difference in weight percent distilled at 350^{o}C and 553^{o}C for the VGO and DAO, respectively. A conversion rate is defined by the following equation [Carrazza, 1997]:

$$Conversion = \frac{R_i - (R_f + C)}{R_i}$$

Where, R_i is the amount of hydrocarbon in the feedstock with a boiling point above the temperature of conversion, R_f is the amount of hydrocarbon in the product with a boiling point above the temperature of conversion and C is the amount of asphaltenes/coke produced in the process.

Based on the conditions of the CSC upgrading, stability test results and mass balances approaching 100%, it is assumed that negligible amounts of asphaltenes/coke are formed during the upgrading trials.

Micro Carbon Residue Testing

Micro Carbon Residue (MCR) Testing, otherwise known as the Ramsbottom Carbon Residue (RCR), is used to determine the relative tendency of the crude oil to carbon deposits by determining the amount of carbonaceous residue formed due to upgrading [Peluso, 2011]. MCR testing is performed in accordance with methodology developed by Hassan et al. at the University of Calgary [Hassan, 2008]. This standard operating procedure for MCR testing determination provides results which are directly comparable to testing methods ASTM D4530 (Carbon Residue) and ASTM D189 (Conradson Carbon Residue).

MCR testing is required for selecting the representative upgrading conditions as it gives an indication of the undesirable deposit forming tendencies of the product, which can affect both pipeline transport and downstream refinery operations, as well as an indication of relative combustibility. Therefore, the ideal upgraded products show significant conversion levels while minimal MCR results. MCR testing is used to evaluate upgraded VGO products where a MCR value less than 4 wt. % is desired (personal communication Pedro Pereira). The accuracy of the MCR testing is dependent on the accuracy of the scale being used to measure the change in mass due to heating. For this study, the mass of the samples is measured to the tenth of a milligram. Full MCR analysis results can be found in Appendix D.

Stability Test (P-Value Testing)

Stability testing is used to characterize the stability of the asphaltenes in a crude oil, as a measure of undesirable asphaltene deposition behavior or fouling tendencies. Many methods have been developed for assessing the relative stability of an oil sample such as spot testing (ASTM D4740), total sedimentation testing (ASTM 4870) and peptization value (p-value). Stability testing for the DAO upgraded samples is performed in accordance with the standard operating procedure for P-value determination as developed by Shell [Di Carlos, 1992].

The P-value is based on a stability scale used for characterizing heavy oils with respect to the tolerance limits established for transportation [Pereira, 2013]. A P-value of 1 is considered unstable oil and the threshold for onset of instability is set at a P-value of 1.15 for this study (personal communication Lante Carbognani). Therefore, the upgraded DAO product from this evaluation requires a P-value greater than or equal to 1.15. This study measures P-value in increments of 0.05.

The P-value gives a measure of the state of peptization of the asphaltenes in the presence of hexadecane. Stability is measured with respect to the volume of hexadecane required to promote asphaltene deposition (peptization of asphaltenes). The P-value test provides a measure of the stability of the sample by determining the minimum volume of hexadecane required to form visible asphaltene precipitate at 40 times magnification. The P-value is calculated using the equation below, where the $ml_{hexadecane}$ refers to the minimum volume required for observable precipitation of asphaltenes and g_{sample} is in reference to the sample weight.

$$P - Value = 1 + \frac{ml_{hexadecane}}{g_{sample}}$$

The hexadecane is dispensed with a burette and the sample weight is calculated to the hundredth of a gram. This method for P-value testing relies on operator consistency in measurements and requires testing to be completed within one day of the upgrading process as the instability of the oil will decrease over time. Additional uncertainties due to human error can be assumed for products containing the catalyst because it is difficult to distinguish catalyst from precipitated asphaltenes. Full P-value analysis results can be found in Appendix C.

Viscosity testing

Viscosity testing is a fundamental characterization method for crude oils. The viscosity, or resistance to flow, is a critical parameter for characterizing the transportability of heavy oils in pipelines due to current infrastructure limitations. Viscosity of crude oils varies significantly depending on temperature and therefore viscosity measurements need to be carried out at a range of temperatures. Pipeline specifications vary depending on weather and therefore operations in Northern Alberta would require lower minimum viscosities compared with a more temperate climate. Minimum kinematic viscosity of crude oils is regulated to be 350 centistokes (cSt) at the lowest pipeline operating temperature [Tsaprailis, 2013]. This chapter addresses measuring the viscosity of the partial-SCOs and does not address the subsequent dilution processing for meeting pipeline viscosity requirements. Viscosity calculations for the mixing of liquids, used to determine the relative composition of the higher viscosity partial-SCO and lower viscosity diluent mixture, are discussed further in Chapter 4.

For the purposes of representing these crude oils in the LCA model the dynamic viscosity (absolute viscosity) is measured for the oil samples. This measurement is performed using a DV-II+ Pro Brookfield viscometer®. The standard fluid accuracy for this instrument is 1% of the fluid value in cP and the instrument accuracy is 1% of the full scale range. Temperature dependent viscosity measurements, at 15^{o}C, 25^{o}C and 40^{o}C, are achieved with a TC-502 Brookfield glycol bath®.

Density testing

Density testing is another fundamental characterization method for crude oils. The crude density is another temperature dependent characteristic which is used for characterizing the transportability of heavy oils. Though density requirements are not as prevalent in literature as viscosity, minimum densities requirements for Canadian commercial pipelines are typically quoted with respect to the operational temperature [Tsaprailis, 2013]. Density testing is thus required to understand the behaviour of the crude with temperature. Density calculations for the mixing of liquids, used to determine the relative composition of the higher density partial-SCO and lower density diluent mixture, are discussed further in Chapter 4.

Density testing is completed in accordance with solution pycnometry measurements for density determination of heavy hydrocarbons [Carbognani, 2011]. The densities of the samples are measured at a variety of temperatures using 10 mL ACE Glass Incorporated (5475-05) pycnometer®. Temperature control is achieved using a laboratory water bath.

API Gravity

American Petroleum Institute gravity (API gravity) is a measurement index for characterization of the relative density of the crude oil to water, where an API gravity (or density) of less than 10^{o} indicates a crude oil that would sink in water. API gravity is a commonly used standard in the petroleum industry and is typically used for classifying crudes. The API gravity calculation uses the ratio of the density of the oil (ρ_{oil}) to water (ρ_{water})at 15.5°C; also referred to as the specific gravity (SG) of the oil. The equation below shows the relation used for calculating the API gravity:

$$API\ gravity = \frac{141.5}{\rho_{oil}/\rho_{water}} - 131.5$$

Elemental analysis

Characterization of the elemental composition of the crude oils is essential not only for determining the amount of upgrading and effect of the catalyst but also because it is required for modeling the crude oil as part of the integrated WTW LCA model, presented in Chapter 4. Elemental analysis is performed to determine the carbon, hydrogen sulphur and nitrogen content of the feedstock and upgraded products. Gas chromatography microanalysis techniques are performed by University of Calgary Chemistry Department and the composition results, found in Table 2.6, are reflective of their measurements.

2.4.4 CSC Upgrading Results

The pilot plant evaluation for the upgrading of VGO and DAO is accomplished for steam-thermal cracking and CSC upgrading. The conditions for upgrading, as shown in the experimental plan, are maintained to the best of the operator's ability throughout the duration of the experiments. The reactor temperature represents the average temperature between the temperature readings from the internal thermocouple probes. The conditions for the space velocity of the crude oil during upgrading, defined by the volume of crude oil passing through the reactor per hour, is calculated based on the manually set flow rate of pumping. The steam concentration is also calculated based on the manually set flow rate for pumping. A summary of the temperature, space velocity and steam concentration conditions for upgrading can be seen in Tables 2.2 and 2.3.

Table 2.2 Properties of upgraded VGO

	T (^oC)	P (psi)	LHVS (hr^{-1})	H2O wt%	Ni (ppm)	K (ppm)	Hydro-carbon MB (%)	Conv % (350^oC)	Liquid Product (%)	Viscosity 25C (cP)	Viscosity 40C (cP)	Density 23^oC (kg/m^3)	MCR, wt%
Steam-Thermal VGO	430	400	2	5	-	-	99.1	30.7	94.6	50.0	22.5	-	1.34 ± 0.05
CSC VGO Condition 1	440	400	2	5	181	387	101.2	39.1	96.0	39.1	18.4	958.5	2.52 ± 0.06
CSC VGO Condition 2	**445**	**400**	**2**	**5**	**181**	**387**	**101.9**	**53.6**	**91.2**	**33.2**	**16.0**	**965.5**	**2.96 ± 0.47**
CSC VGO Condition 3	440	400	1.7	5	181	387	100.3	48.1	92.3	37.3	17.3	965.1	3.04 ± 0.33
CSC VGO Condition 4	435	400	1.7	5	181	387	99.8	47.9	89.5	37.1	17.9	947.5	2.52 ± 0.03

Table 2.3 Properties of upgraded DAO

	T (^oC)	P (psi)	LHVS (hr^{-1})	H2O wt%	Ni (ppm)	K (ppm)	Hydro-carbon MB (%)	Conv % (553^oC)	Liquid Product (%)	Viscosity 25C (cP)	Viscosity 40C (cP)	Density 15^oC (kg/m^3)	API	P-Value
Steam-Thermal DAO	425	400	3	4.7	-	-	97.4	43.5	90.6	24640	4764	-	-	1.2
CSC DAO Condition 1	440	300	3	4	366	574	97.4	62.6	87.8	13644	2895	1023	6.7	1.15
CSC DAO Condition 2	435	300	3	4	366	574	100.7	55.0	87.9	8968	2113	1024	6.5	1.2
CSC DAO Condition 3	435	300	3.2	4	366	574	99.1	55.6	87.5	11102	2423	1014	7.9	1.2
CSC DAO Condition 4	**440**	**300**	**3.2**	**4**	**366**	**574**	**98.1**	**64.2**	**90.2**	**7184**	**1660**	**1014**	**7.9**	**1.2**

Figure 2.4 Simulated distillation curves from VGO upgrading

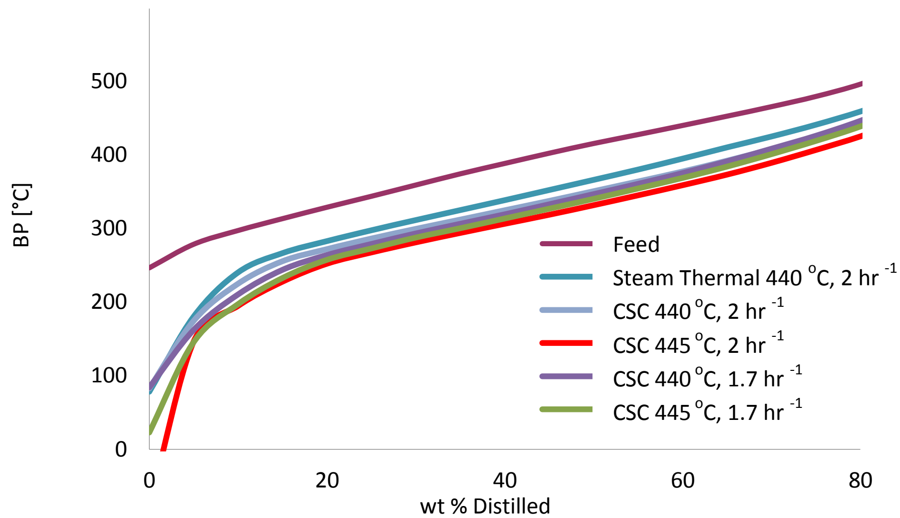
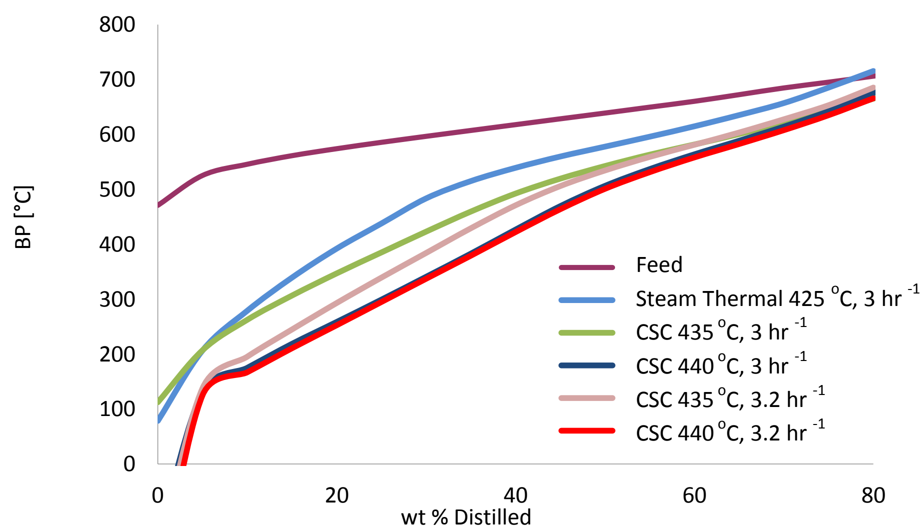


Figure 2.5 Simulated distillation curves from DAO upgrading



Boiling point curves for the respective upgraded VGO and DAO products are plotted using data obtained from the gas chromatography, mass calculation during pilot plant experimentation, and the simulated distillation of the light and heavy upgraded products. The distillation curves represent the upgraded products collected from the hot and cold separators and are reflective of relative weight of the respective products. The product boiling point curves shift to lower boiling points with increased levels of upgrading due to more of the heavy/high boiling point feedstock being converted into desirable lighter products. These boiling point curves can be seen in the Figures 2.3 and 2.4 as well as in Appendices A and B.

Conversion rates for the respective upgraded products, calculated based on the difference between the simulated distillation curves of the feedstock and products at a specific temperature, are used as a primary indicator of the level of upgrading. Conversion rates are displayed along with a summary of the other product analysis results for VGO and DAO upgrading trials in the Tables 2.2 and 2.3.

The effectiveness of the catalyst is observed with the increase reaction temperatures and conversion rate of CSC upgrading in comparison to steam-cracking upgrading with similar levels of asphaltene stabilization, as seen in Tables 2.2 and 2.3 found later in this section.

The ideal upgrading conditions for the CSC upgrading of VGO and DAO feedstocks are then selected for formulation as part of a final upgraded product. Crude characteristics such as reduced viscosity and density are considered the primary selection criteria when comparing upgraded VGO and DAO products which met above stated stability and MCR requirements. Other factors considered when selecting the representative VGO and DAO upgraded products for CSC partial-upgrading are the percentage of liquid product and gas products; which affects to total volume of partial-SCO product from the CSC partial-upgrading plant.

Based on the results from upgrading trials, the upgraded VGO product from condition 2 and the upgraded DAO product from condition 4 are selected for representing the CSC upgrading process unit condition and products for CSC partial-upgrading.

2.4.5 CSC Partial-Upgrading Product Formulation

For this study, the CSC partial-SCOs are formulated from the upgraded VGO and DAO fraction and unprocessed lights and pitch fractions. The relative amounts of the various crude fractions for the formulation of the final product are with respect to the boiling point characteristics of the original Athabasca Bitumen, as described earlier in Section 2.3.1, Feedstock Fractionation and Separation.

The CSC partial-upgrading product formulation is performed using a batch reactor with a 100^{o}C reactor temperature, 500 revolutions per minute (RPM) mixing speed and a nitrogen pressurization of 200 psi. A comparison of the masses of the various fractions (such as light, upgraded VGO, etc.) used in the formulation of the CSC partial-SCOs verses the theoretically calculated masses, based on the simulated distillation boiling point characteristics of the Athabasca bitumen , can be seen in Section 2.4 Results.

The CSC partial-SCOs are then characterized to better understand the effects of CSC partial-upgrading. The CSC partial-SCOs are characterized to observing trends in the elemental and micro carbon residue compositions as well as the boiling point characteristics in comparison with the bitumen sample.

2.4.6 CSC Partial-Upgraded Product Results

Tables 2.4 and 2.5 summarize the theoretical and actual amounts of the upgraded and non-upgraded crude oil fraction used in formulation of the CSC partial-SCOs. The two CSC partial-SCOs formulations are reflective of the operator's choice to incorporate or not to incorporate pitch in the upgraded product, as discussed in Section 2.1. The calculation of theoretical amounts of the respective crude oil fractions in the CSC partial-upgrading product are based on the original Athabasca Bitumen boiling point properties.

Table 2.4. Formulation of CSC partial-SCO with re-incorporated pitch

	Theoretical Quantity		Formulation Quantity		Percentage error	
	Recovered Heavy Products	Recovered Light Product	Recovered Heavy Products	Recovered Light Product	Heavy Product	Light Product
Lights	6.7 wt. %	-	6.7 wt. %	-	0.0 %	-
Upgraded VGO	33.2 wt. %	5.4 wt. %	33.2 wt. %	5.4 wt. %	0.0 %	-0.8 %
Upgraded DAO	36.9 wt. %	5.3 wt. %	37.0 wt. %	5.3 wt. %	0.1 %	-0.5 %
Pitch	12.5 wt. %	-	12.6 wt. %	-	0.4 %	-

Table 2.5. Formulation of CSC partial-SCO without re-incorporated pitch

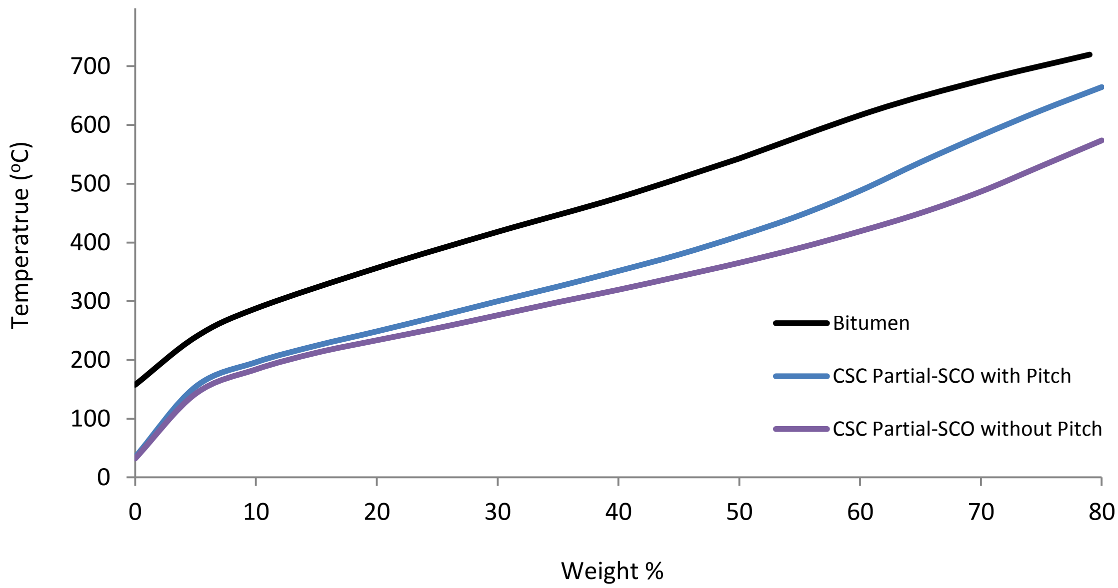
	Theoretical Quantity		Formulation Quantity		Percentage error	
	Recovered Heavy Products	Recovered Light Product	Recovered Heavy Products	Recovered Light Product	Heavy Product	Light Product
Lights	7.7 wt. %	-	7.8 wt. %	-	0.6 %	-
Upgraded VGO	37.9 wt. %	6.2 wt. %	37.9 wt. %	6.2 wt. %	-0.1 %	-0.3 %
Upgraded DAO	42.2 wt. %	6.0 wt. %	42.1 wt. %	6.1 wt. %	-0.2 %	1.2 %
Pitch	-	-	-	-	-	-

In the CSC partial-upgrading product formulations found in Tables 2.4 and 2.5, the relative volumes of the heavy and light products refer to the relative weight of collected product in the hot and cold separators during the upgrading of VGO and DAO. The percentage error column refers to the difference between the theoretical quantity and the actual quantity added of the respective fractions. A positive error percentage is reflective of a higher quantity of that fraction in the CSC partial-SCO product sample compared with the theoretical formulation. The formulations of CSC partial-SCOs are found to be very close to the theoretical formulations.

The formulated upgrader CSC partial-SCOs, with and without pitch re-incorporated, are further analyzed for viscosities and densities properties. The CSC partial-upgrading product with pitch re-incorporated is found to have viscosities of 780 cP and 693 cP at 20^{o}C and 25^{o}C. The CSC partial-upgrading product which did not include pitch is found to have viscosities of 124 cP and 107 cP at 20^{o}C and 25^{o}C. The densities of CSC partial-upgrading products with and without pitch re-incorporated are determined to be and 981 kg/m^3 and 959 kg/m^3 at 15.5^{o}C, respectively. These CSC partial-upgrading products can be more generally defined by API gravity values of

12.5^{o} and 15.8^{o} for the upgraded products with and without the pitch fraction re-incorporated, respectively. Simulated distillation analysis of the partial-SCOs can be seen in Figure 2.5.

Figure 2.6 Boiling point curves for the formulated CSC partial-SCOs



The boiling point characterization found that the CSC partial-SCOs have greatly decreased boiling point curves in comparison with the original bitumen. While the CSC partial-SCOs showed similar boiling point characteristics at low temperatures, the effect of the inclusion or rejection of pitch is evident with the increased weight percent of high boiling point hydrocarbons. For example, the sample the CSC partial-SCO with pitch has approximately 11 weight percent fewer products boiled-off in comparison with the CSC partial-SCO without pitch at 575^{o}C.

Finally, a summary table of the elemental analysis and MCR analysis of the CSC partial-SCOs can be seen in Table 2.6.

Table 2.6. Elemental and MCR analysis results for the formulated CSC partial-SCOs

	Carbon	Hydrogen	Nitrogen	Sulphur	MCR
Athabasca Bitumen API 9.5°	83.5 wt. %	11.1 wt. %	3940 ppm	40600 ppm	13.13 wt. %
CSC partial-SCO with pitch API 12.5°	83.0 wt. %	11.1 wt. %	3580 ppm	33400 ppm	13.72 wt. %
CSC partial-SCO without pitch API 15.8°	82.0 wt. %	10.9 wt. %	3030 ppm	29800 ppm	9.35 wt. %

This elemental analysis is performed on microgram sample size due to limited production volume from the pilot plant upgrading process unit. This elemental analysis is primarily used to observe trends in sulphur, nitrogen, hydrogen and carbon content. The precision accuracy required to infer oxygen content is not reliable for microanalysis [personal communication Lante Carbognani]. The CSC partially-upgraded samples showed a decrease in nitrogen and sulphur content and a slight increase in ratio of hydrogen to carbon ratio. The CSC partial-SCO with pitch is found to have a slight increase the MCR content in comparison with the original bitumen sample while the removal of pitch caused a decrease in MCR for the other CSC partial-SCO.

2.5 Discussion

The pilot plant study is intended to best represent the CSC partial-upgrading process for use in GHG emissions and economic comparison of oil sands pathways, found later in this thesis. The applicability of this pilot plant study in representing the industrial process and the results from the evaluation which will be used as a basis for the LCA and cost-benefit analysis is discussed in this section.

This pilot plant experiment relies on crude oil fractions provided by Nexen Inc., Core Laboratories, and SDA processing at the University of Calgary. Due to the outsourcing of separation processes to obtain the required crude oil fractions it is determined, with SimDist analysis, that the final boiling point of the VGO fraction (514°C) did not match the initial boiling point of the DAO fraction (545°C). Therefore, this pilot plant study did not reflect the processing of this small crude oil fraction (approximately 4 wt. %). However, this omitted fraction from the pilot plant experiment is later accounted for through the addition of 4 weight percent to the

Vacuum Residue fraction (525^oC^+) of the crude oil assay, presented in Chapter 4. The addition of this weight percentage to the crude oil assay assumes that this fraction did not benefit from the CSC upgrading; which would not be reflective of the industrial process. A demonstration scale CSC partial-upgrader plant that includes these separation processes could better represent the partial-SCOs through the complete use of a single crude oil source.

Ideally, this pilot plant evaluation could better represent the CSC partial-upgrading process if SDA processing were completed as part of this study. The SDA processing of the residue from the fractionation residue fraction (514^oC^+), provided by Core Laboratories, would ensure that the output DAO and pitch products are representative of a single crude oil. Additionally, the products and conditions of the SDA process could be used to better inform the life cycle assessment of the upgrading process, as described further in Chapter 3.

As presented in the experimental plan in Table 2.1, the targeted amount of catalyst added to the feedstock during the ultra-dispersion catalyst preparation is 300 ppm nickel and 500 ppm potassium. Based on the metal content analysis, the actual amounts of catalyst added to the respective samples varied from these targeted concentrations by up to 125 ppm. Though the catalyst concentrations varied, the catalyst concentrations remained above an atomic ratio of 0.3, as desired for CSC upgrading [Pereira, 2012].

The difference between the desired catalyst content and the actual amount of catalyst added to the crude oil fractions can be attributed to the operation of the catalyst preparation process unit and the properties of the feed. Previous operations of the catalyst preparation process unit found that sedimentation and agglomeration of the catalyst particles during the catalyst preparation of the feedstock caused some metal contentment to be trapped in the upgrader unit. Additionally, the catalyst preparation process unit uses numerous independent pumps and therefore the efficiency of these pumps can significantly affect the catalyst concentration. The viscosity of the feed is also a crucial factor in catalyst preparation as more dense crude oils are able to better suspend more catalyst in comparison with lighter oils. For this reason, the lowered catalyst concentration observed in this study (approximately 30%) in the prepared VGO in comparison with the DAO feedstock is expected.

The results of the upgrading is evaluated for using parameters such as conversion level, viscosity, density, and liquid product yield when standards for hydrocarbon mass balance, stability and MCR are met. Based on the product analysis, it is seen that CSC upgrading is able to achieve conversion levels of up to 53% at 350^{o}C for VGO and 64% at 553^{o}C for DAO samples. This level of conversion is in agreement with previous CSC evaluation trials which found VGO conversion rates of over 50% at 350^{o}C were able to be achieved with the same MCR constraints (under 4%) [Trujillo, 2008]. Additionally, the conversion levels obtained in the DAO trails are reflective of the Nexen Inc. study performed that found up to 70% conversion of DAO with P-values or 1.15 or greater [Nexen, 2012]. Due to similar results obtained in this study compared with previous studies, extensive repeatability of upgrading conditions and evaluations with feedstocks were not addressed for this study but would greatly benefit further process development efforts.

The effect of the catalyst can be seen from the difference between the steam-thermal conversion runs and the catalyst upgrading as well as GC and elemental analysis. The effect of the catalysts to stabilize the upgrading reactions at higher temperatures can be seen with an improved conversion rate (approximately 10-20%) and improved stability (higher measured P-values for VGO) or similar MCR results (less than the 3 wt. % for DAO) in comparison with steam-thermal upgrading, as displayed in Tables 2.2 and 2.3. Additional steam-thermal upgrading performed at the same reaction temperature conditions could be used to further demonstrate the effectiveness of the catalysts.

The production of hydrogen and hydrogen sulphide, as observed with GC analysis found in Appendix E, is indicative of reforming reactions facilitated by the catalyst. However, the gas production during upgrading has lower levels of hydrogen and hydrogen sulphide than that of previous CSC studies [Nexen, 2012]. These lower levels of hydrogen and hydrogen sulphide in the off-gas can be indicative of increased relative effects of thermal cracking in comparison with the catalytic reforming. However, due to the difference in feedstock and process unit operator, it is difficult to make conclusions regarding the exact reaction mechanism and effects of catalysts. The effects of this CSC partial-upgrading process with respect to the gas product are addressed in Chapters 3 and 4.

Finally, the elemental analysis of the CSC partial-upgrading products in Table 2.6 shows that the hydrogen to carbon content ratios increased compared with Athabasca bitumen. Additional steam-thermal upgrading conditions without catalysts could provide more information with respect to the hydrogenation benefits of these ultra-dispersed catalysts during CSC upgrading. When this technology is further developed to allow for large sample sizes, it is then anticipated that elemental analysis would more accurately reflect elemental contents including oxygen.

The upgraded VGO and DAO products used in the formulation of the CSC partial-upgrading products are selected based on the criteria outlined in the method for pilot plant evaluation. However, in both the case of selecting representative upgrading conditions and VGO and DAO products, it is observed that the other temperature and space velocity conditions showed similar levels of conversion at the same stability or MCR levels (see Tables 2.2 and 2.3). The choices of representative upgrading conditions and products for this CSC partial-upgrading evaluation can have significant effects on the resulting emissions and economic analysis. For example, factors such as the relative amount of process gas and liquid product are essential in the assessment of the CSC partial-upgrading pathway with respect to industrial scale application, as discussed further in Chapter 3. The properties of the CSC partial-upgrading products will have the most significant effect on the full LCA emissions results due to calculations of additional diluent required for meeting minimum pipeline specifications and the modeling of the CSC partial-upgrading product as a crude oil assay in the integrated LCA model for determining downstream emissions attributed pipeline transportation, refining and end product. The effects of the crude properties on downstream processing will be explored further in the comparative LCA study presented in Chapter 4.

Based on the selected VGO and DAO upgrading conditions, the formulation and analysis of the final upgraded products, partial-SCOs, is completed to allow for the upgraded oils to be characterized and represented in the subsequent emissions and economic analysis found in chapters 3 and 4. The formulation of the upgrader product which did not re-incorporate pitch material is determined to have an API gravity of 15.7^o and a viscosity of 104 cP at 25^{o}C which exceeded the minimum level of upgrading claimed in the patent (characterized by an API gravity above 15^o and a viscosity below 350 cP at 25^{o}C) [Pereira, 2013].

Due to the limited sample sizes obtained from the pilot plant evaluation, the CSC partial-upgrading product is formulated in 20 g batch samples. The amount of a specific crude fraction added during formulation varied from the theoretical product composition by up to 1.2 weight percent. Larger scale testing could allow for increased precision with respect to product formulations which could affect the CSC partial-SCOs characteristics. Larger scale formulations can only be accomplished once CSC partial-upgrading is assessed at larger scale demonstration projects, operating at higher capacities, due to the limitation of the quantities of crude oil which can be processed at a bench scale pilot plant evaluation.

The operational decision to remove pitch could have an additional benefit of being used to meet the energy demand of the CSC partial-upgrading plant. For example, the use of pitch as a fuel source would be most beneficial in the application of CSC partial-upgrading in remote locations or employed for small scale exploration and development project where supply chain logistics can be more difficult. The emissions impacts of using the pitch fraction as a self-sustaining energy source for the CSC partial-upgrading plant operation would increase operational GHG emissions in comparison with a lower emitting energy source such as natural gas (assuming no additional GHG emissions mitigation technologies such as carbon capture). For example, Argonne National Laboratory's GREET model estimates for emissions from petroleum coke combustion to be 96.8 g CO_2e/MJ where as a literature review from ICF Consulting Canada found full life cycle emissions ranging from 56 to 68 g CO_2e/MJ for conventional natural gas (with the highest emissions estimate of 76 g/MJ in the case of shale gas) [Argonne National Laboratory, 2012. ICF CONSULTING CANADA, 2012].

There are additional logistical and infrastructure benefits for using a material produced on site as a primary energy source. For example, use of this pitch as a fuel source would eliminate a need to responsibly stockpile the tonnes of by-product produced daily. Additionally, it could eliminate the need for additional infrastructure, such as natural gas pipelines, which would be of significant benefit for smaller scale exploration and development projects in remote locations. However, it is likely that the construction of this additional infrastructure would significantly impact emissions over the projects lifetime as emissions attributed to construction are typically an order of magnitude lower than operation and end use emissions for energy LCA studies [Bergerson, 2006].

Because current industrial oil sands operations primarily use natural gas as the fuel source, this study assumes that natural gas is used for meeting operational fuel requirements and that the removed pitch material is stockpiled. However, if cheap and effective carbon capture is possible and natural gas costs increase significantly then there could be a case for re-evaluating this pathway with use of pitch as a fuel source.

2.6 Conclusions

The pilot plant evaluation is able to effectively produce upgraded crude oils as well as provide information regarding operational conditions which are essential for developing emissions and economic assessments of CSC partial-upgrading. The pilot plant showed, in accordance with minimum evaluation standards for asphaltene precursor production (as defined by P-value and MCR testing), this CSC upgrading is able to achieve up to a 53% conversion rate at 350^{o}C for VGO with 5 weight percent steam and approximately 200 and 400 ppm of Ni and K catalyst. The pilot plant also showed CSC upgrading can achieve up to a 64% conversion rate at 553^{o}C for DAO with 4 weight percent steam and approximately 350 and 575 ppm of Ni and K catalyst. Based on the selection of representative upgrading runs, CSC partial-upgrading products are formulated from: 1) light, upgraded VGO, upgraded DAO and pitch; 2) light, upgraded VGO and upgraded DAO (with pitch assumed to be removed and stockpiled). Identifying the upgrading conditions provided further information pertaining to process requirements, such as steam and catalyst concentration, which are used for informing the industrial application modeling of this CSC partial-upgrading in Chapter 3. The CSC partial-SCO which re-incorporated pitch is found to have an API gravity of 12.5^{o} and viscosities of 780 cP and 693 cP at 20^{o}C and 25^{o}C, respectively. The CSC partial-SCO which did not include pitch is found to have an API gravity of 15.8^{o} and viscosities of 124 cP and 107 cP at 20^{o}C and 25^{o}C, respectively. This pilot plant study is able to further characterize some of the crude properties, such as elemental composition, which is later used to model these crude oil products as part of integrated WTW LCA model in Chapter 4.

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3.0 LCA of the Potential Industrial Scale Implementation of the CSC Partial-Upgrading Process

Catalytic steam cracking (CSC) partial-upgrading is currently being evaluated at the pilot plant scale for the investigation of effects such as conversion and stability based on varied operational conditions such as temperature, steam and catalyst concentrations. The scope of the pilot plant study, presented in Chapter 2, includes key process units for catalyst preparation and CSC upgrading involved with CSC partial-upgrading while omitting other processes unit, such as distillation towers or amine gas treater, which would also be required for the industrial plant. While process units that are commonly used in industry can be modeled with engineering simulation tools and industrial correlations from literature, projecting industrial process requirements are more difficult for these prospective CSC upgrader and catalyst preparation process units.

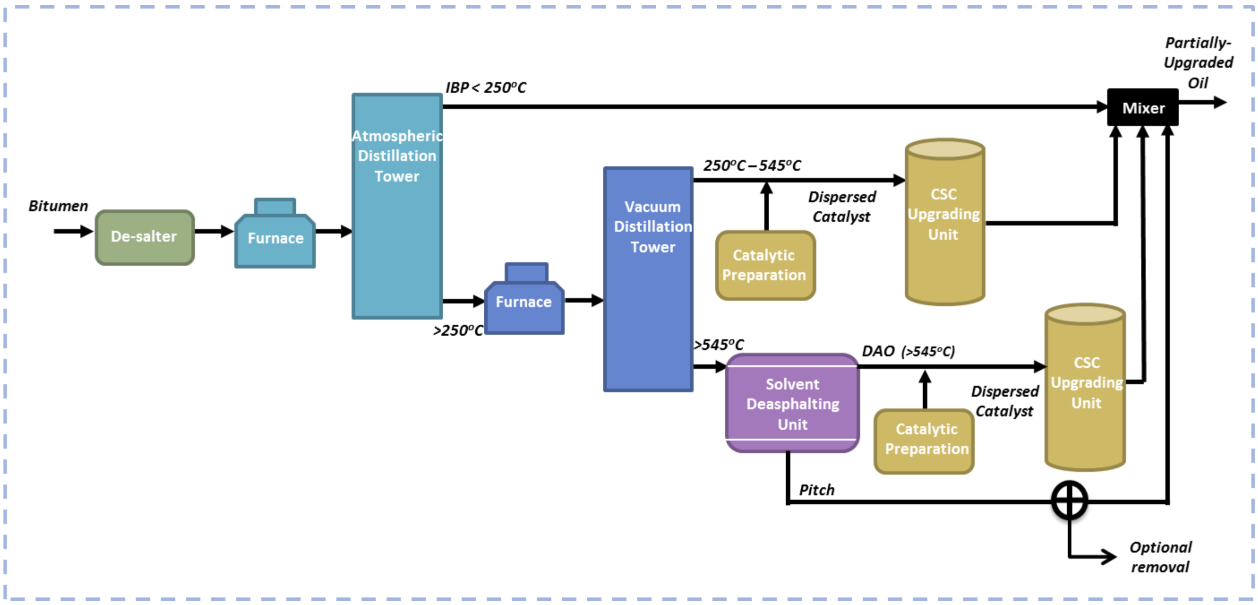
This chapter calculates the process requirements, GHG emissions and capital, and operational and maintenance (O&M) costs for the CSC partial-upgrader if deployed at industrial scale. This chapter presents estimates for the operation of a 100,000 barrel per day (bpd) industrial facility. The process requirements for the CSC partial-upgrader are calculated using an engineering simulation tool, Aspen HYSYS®, and industrial correlations from literature. The GHG emissions are calculated based on the plant process requirements using established emissions intensity factor correlations. The capital and O&M costs are calculated based on process unit correlations from literature. These GHG emissions estimates are in turn used to represent the upgrading stage emissions as part of the WTW life cycle emissions comparison in Chapter 4. These emissions estimates are then connected to upstream and downstream activities to represent the full life cycle impacts of the CSC partial-upgrading pathway. The economic calculation and WTW GHG emissions are used for an economic comparison of investment options for oil sands pathways in Chapter 4. This chapter estimates potential industrial scale impact of an integrated CSC partial-upgrading, which employs both process units with proven industrial applicability as well as process units which are currently being evaluated at the pilot plant level.

3.1 Introduction to CSC Partial-Upgrading

The pilot plant study effectively determined key parameters, such as the CSC partial-SCO properties as well as steam and catalyst concentration, required for CSC upgrading and catalyst preparation. However, process/duty requirements, such as fuel or electricity, cannot be directly adapted from pilot plant performance due to operation of only a few of the required process units for an industrial plant and operation at a limited scale which is not reflective of integrated industrial operations. Differences between the pilot plant set up and industrial application which do not allow for direct scaling of process requirements can be seen through the use of electrical reactor heating at a pilot plant scale when industrial process units would instead use a pseudo-adiabatic process for reactor heating using natural gas boilers and integrated heating and cooling systems. Similarly, the gearing pumps used at a pilot plant scale are not representative of centrifugal pumps which are used at industrial scale. However, industrial scale equipment, such as the use of pseudo-adiabatic processes for reactor heating, are conventionally employed in industry and therefore process requirements for emerging process units can be estimated from established process units operating with similar processes and conditions (such as crude oil conversion performed at similar pressure, temperature, feed properties etc.). Process requirements, such as electricity, fuel, etc., for the prospective CSC upgrading unit are therefore assumed to be representative of process requirements for industrially established Visbreaking and thermal cracking process unit, operating at similar condition, for the purpose of this study.

To effectively assess CSC partial-upgrading for use in subsequent life cycle comparisons with established pathways, a thorough account of process requirements must be estimated for the industrial scale process units. In addition to estimating process requirements of the catalyst preparation and CSC upgrading process units involved with the pilot plant evaluation, CSC partial-upgrading also requires additional crude processing, treatment of produced gases, and steam and cooling water systems. The crude also undergoes de-salting, atmospheric and vacuum distillation, and solvent de-asphalting (SDA). Gases produced from the upgrading process require amine gas treatment and sulphur recovery. Plant steam and cooling water systems are designed to meet the total steam and cooling water process requirements of the above mentioned industrial units. Therefore, the industrial scale implementation of this CSC partial-upgrader involves forecasting the process requirements for the catalyst preparation and CSC upgrading process units evaluated as part of the pilot plant evaluation as well as commonly employed industrial units including a de-salter, atmospheric distillation furnace and tower, vacuum distillation furnace and tower, SDA, amine gas treatment, sulphur recovery, cooling water system and steam system. Figure 3.1 outlines the primary process units used in CSC partial-upgrading.

Figure 3.1 Process unit diagram of CSC partial-upgrading



3.2 Introduction to Industrial Scale Implementation of CSC Partial-Upgrading

Estimating industrial scale process requirements before construction of large processing plants can be a helpful step in better understanding operational behaviour and identifying critical areas of further development. Typically, with pilot plant studies, the process units are developed to be adaptable for investigating specific sets of critical parameters which can be assumed to be scalable for industrial processes [Ancheyta, 2011]. In the case of this upgrader evaluation, Chapter 2 identified the main operating conditions for temperature, pressure, space velocity, required catalyst and steam concentrations to produce the CSC partial-SCOs. It has been shown that these main operating conditions and products from a pilot plant or demonstration scale effectively emulate the performance of industrial process units using the same feedstock and reaction conditions [Maya-Yesca, 2006]. Therefore, these main operating conditions and the partial-SCOs from the pilot plant experiment are assumed to be representative of an industrial application for the same catalyst and feedstock. As indicated in Section 3.0, other critical factors for industrial operation that are not directly scalable from the pilot plant evaluation include process requirements such as electricity, non-process steam (steam used for process heating but not steam supplied to the reactor of the CSC upgrading unit) and fuel requirements. These industrial scale process requirements are estimated to be representative of similar industrial scale process units that operate at similar conditions, such as pressure, temperature, etc., because it is assumed that the CSC upgrading unit would employ similar heating, pumping, etc. systems when deployed at an industrial scale. Industrial correlations for a Visbreaking and thermal cracking process unit, operating at similar condition, are assumed to be representative of the CSC upgrader process requirements which could not be directly scaled from the pilot plant.

To further illustrate the scalability issues faced in assessing this CSC upgrader process unit, Table 3.1 compares differences between industrial scale operations and pilot plant evaluations.

Table 3.1 Operational differences between the upgrader at pilot plant evaluation and potential industrial implementation

	Pilot Plant Upgrader	Industrial Upgrader	Scaling impacts
Upgrading Process requirements	Specific requirements for steam and catalysts* are reflective of industrial process but inefficient use of electricity for heating, steam production, etc. is not reflective of an optimized process	Based on optimized process unit operations and integrated heat, gas product, water etc. across process units	Steam and catalyst requirements are scaled based on pilot plant study but other energy and material requirements are estimated based on industrial correlations to similar processing units at the same capacity
Operation mode	Short processing periods where operation is intended to replicate steady state conditions	Continuous on-stream plant operation which achieves steady-state conditions	Assume pilot plant products and main operating conditions are representative of the industrial scale process
Production capacity	Kilograms of crude oil per day	Tonnes or Kilotonnes of crude oil per day	Assume analysis techniques used for limited product volumes are representative of industrial CSC product

*Catalysts are identified as an area which may not be directly scaled from a pilot plant evaluation, i.e. in the case of fluid catalytic cracking units (FCC) [Ancheyta, 2011]. However, the ultra-dispersed nano-catalysts used in CSC are not representative of the catalysts used in FCC as FCC catalysts are typically comprised of crystalline zeolite, matrix, binder, and filler components with an overall particle size in the range of micrometers. Additional evaluation and sensitivity analysis of process requirements can be found later in this chapter.

Systems optimization and integration of energy streams between process units at an industrial scale can lead to significant reductions in emissions compared to independently operating process units. For example, excess heat can be used to preheat or produce steam and therefore offset the natural gas that would otherwise be consumed. Due to the reasons previously stated, these energy process requirements are not able to be scaled up for the pilot plant process units and have to be estimated based on similar industrially employed process units which would be operating as part of an integrated plant. With the expectation of the engineering modeling, this investigation of industrial scale process requirements and emissions impacts does not specifically address the process units operating in an integrated system and therefore the process optimization or system inefficiencies are intended to be captured in the range of high and low emissions impacts established in this chapter (discussed further in Section 3.3, Methods). This study captures a minimal level of integration through assuming the off-gas produced from the CSC upgrader process unit, as determined through off-gas characterization during the pilot plant study, can be assumed to be usable to offset other fuel requirements of the industrial plant. Additionally, the framework presented for projecting industrial scale impacts could be further developed with analysis techniques, such as Pinch analysis [Ebrahim, 2000], to identify further heat and power integration based on the engineering simulation modeling found in this chapter.

The use of short processing periods and batch processes between process units during the pilot plant evaluation has several implications when using the data collected for the assessment of the potential for industrial application. For example, short processing periods are likely to result in more variability between separate runs at the same conditions. Additionally, independent process units affect the time between preparation of the upgrading feedstock with catalyst and the CSC upgrading where a longer delay can allow for catalyst particle agglomeration and sedimentation which could affect catalyst activity and conversion rate. Once the main operating conditions and process requirements are established at the pilot plant scale it is common practice to optimize a demonstration scale process plant to better understand the reproducibility of experiments and effects of practices such as on-stream catalyst preparation on the average particle properties, concentrations and efficiency of catalysts processing. For the purpose of this study, it is assume that the results obtained from these short processing times and batch processing between process units would have a negligible effect on the pilot plant results. Therefore, the products of the pilot plant experiment are assumed to be representative of an industrial process and further systems optimizations are again captured with high and low impact estimates.

Similar scaling issues arise when predicting industrial requirements and impacts of the emerging catalyst preparation process unit. The pilot plant evaluation of this process unit is used in short processing periods and batch processes between process units. The operation of the catalyst preparation process unit requires the feedstock being preheated, using electrical heating, and numerous pumps for the various catalyst solutions and multiple feedstock tanks to ensure continuous feedstock preparation. When this catalyst preparation process unit is further developed for a demonstration or industrial plant, the feedstock would arrive preheated from previous distillation or solvent deasphalting operations and additional process requirements for heating and pumping would again be facilitated with pseudo-adiabatic heating processes and centrifugal pumps. For this reason, estimating industrial process requirements for the catalyst preparation process unit is performed in a similar manner to the CSC upgrader process unit in this study. Through use of high and low impact estimates, this study intends to capture potential process optimization or inefficiencies which could lead to variable performance of these process units employed at an industrial scale.

CSC partial-upgrading also employs a number of established and conventionally adopted process units at an industrial scale including distillation towers, solvent de-asphalting (SDA), amine gas treatment, sulphur recovery, as well as steam and cooling systems. Industrial scale process requirements of these processes units can be estimated using engineering modeling software and established conditions from literature data. This form of process unit level assessment for process requirement does not predict effects of process integration between process units for industrial scale applications. Therefore, these system inefficiencies or optimizations are intended to be captured by the high and low impact assessments calculated in this chapter. However, a better understanding of potential process integration or optimized plant design could be performed through further development and analysis of the Aspen HYSYS® simulation model.

Engineering simulation software has been developed for an array of purposes, from the assessment of conceptual designs to integrated energy and economic analysis. For the evaluation of the CSC partial-upgrading, Aspen HYSYS®, is used. The modeling program has been developed for chemical plants and oil refineries due to tailored use for chemical and petroleum engineering processes for estimation and assessment of operational requirements and conditions [AspenTech, 2011]. The model is used to estimate integrated processing of the CSC partial-upgrader based on the specific crude feedstock properties as well as process unit configurations and sizing. The Aspen HYSYS® simulation, used for the results presented in this chapter, is able to characterize material and energy balances throughout CSC partial-upgrading and directly analyze duty requirements of the distillation towers and furnaces based on specific crude properties and desired fractionation, as defined by the specific boiling points. These material and energy balances are useful in verifying the operation of the entire plant and process unit capacities as well as specific properties of crude streams/fractions, which can further verify properties of mixed or separated crudes. This engineering modeling tool is not used in the case of process units where further reaction modeling would be required for the simulation. Therefore, industrial requirements for conventional industrial processes, such as SDA, are directly adapted from literature.

Industry based literature that relates energy and material requirements to the crude oil processing units are used to correlate process requirements, such as electricity and fuel, of commonly adopted and established process units based on processing capacity. For example, electricity requirements for a process unit are correlated with *X* kWh per barrel of feed, where the process unit capacity is defined by processing scheme and the boiling point characteristics of the bitumen feedstock. The process scheme, as laid out in the patent for CSC partial-upgrading [Pereira Almao, 2013], has boiling point cuts for different light, VGO, DAO and pitch fractions. Through use of the boiling point curve of the original Athabasca bitumen (Simulated distillation characterization from Chapter 2), the total volume of the various light, VGO, etc. streams are calculated for the industrial process unit capacities.

These process requirement estimates are reflective of an industrial range or average of the process units [Gary, 2001]. However, multiple configurations have been established based on the same technology and subsequently a large range of processing performances have been reported for many crude oil processing units [Gary, 2001]. Additionally, processing performance, such as process requirements and conversion or performance efficiency, is related to the specific crude properties and therefore these estimates do not necessarily reflect the specific feedstock [Gary, 2001]. Therefore, applicable error ranges will be applied to these industrial estimates in an attempt to better represent the potential performance range of this processing based on a variety of technology configurations.

In addition to engineering simulation software and established literature data, this analysis also assumes the industrial performance of the catalyst preparation and CSC upgrader process units, which are currently only under evaluation at a pilot plant scale, can be represented by similar industrially adopted process units operating under analogous conditions. These emerging process units have seen limited adoption and therefore this study relies on Dr. Pereira's previous experience with industrial implementation of these types of process units during his work with PVDSA. For critical process requirements which can be assumed scalable from pilot plant evaluation to industrial implementation, such as steam and catalyst requirements, the base case estimated process requirements and high and low impact are discussed in Section 3.3 [Ancheyta, 2011]. Process requirements which are not assumed to be scalable, such as electricity, fuel, cooling water and make-up water, are based on hydrocracking and gas oil recovery values published by Arthur D'Little. [Pereira-Alamo, 2012]

The estimates for process requirements of the plant operation are then used as a basis of the GHG emissions assessment. Characterized process and material requirements for the process units are then used to calculate GHG emissions associated with this CSC partial-upgrading industrial process based on established literature emissions intensity estimates from literature and databases such as GREET, a model used for assessing GHG emissions of transportation fuels, and a base metal refining study by Forbes et al. [Argonne National Laboratory, 2012. Forbes, 2000]. Characterization of process requirements in terms of GHG impacts allows for direct comparison with current processes and technologies, such as coking and hydrocracking full-upgrading, as well as the identification of the processes or requirements which have the greatest contribution to the emissions impact. This allows for further development of this CSC partial-upgrading process to target energy efficiency and lower GHG emissions impacts. Calculated emissions estimates are in turn used to represent the CSC partial-upgrading as a part of an integrated LCA model in Chapter 4.

Estimates of capital and operations and maintenance costs are based on petroleum refining economics estimates of individual process units and are primarily derived from industrial estimates by Gary and Handwerk and by the company Arthur D'Little [Gary, 2001, Pereira-Almao, 2012]. These estimates of capital costs for industrially adopted process units, including de-salter, distillation furnaces and towers, solvent de-asphalting (SDA), amine gas treatment, sulphur recovery, as well as steam and cooling systems, are based on the calculated processing capacity. The CSC upgrader and the catalyst preparation process unit are only in demonstration scale and therefore industrial estimates are based on a Visbreaker and gas oil recovery by Arthur D'Little [Pereira-Almao, 2012]. The operational and maintenance costs are estimated based on pilot plant established processing requirements, such as required catalysts, and correlations, to the calculated process unit capacities, from industrial estimates for total capital cost by Gary and Handwerk and by the company Arthur D'Little [Gary, 2001, Pereira-Almao, 2012].

3.3 Methods

This evaluation is conducted to represent the industrial scale application of a 100,000 bpd CSC partial-upgrading plant. This industrial plant size is selected as representative of currently proposed SAGD extraction plants, which typically range from 10,000 bpd to over 150,000 bpd [Heavy Oil & Oilsands, 2010]. Table 3.2 summarizes the methods and source for estimating industrial requirements of the process units in this CSC partial-upgrading.

Engineering modeling, Aspen HYSYS®, is used to estimate operational duties based on the simulated distillation of Athabasca bitumen under specified furnace and distillation conditions and defined tower sizing and design. These process units are prebuilt for various configurations, such as use of condensers and/or reboilers, which can be further modified, such as varied number of trays, to allow for industrial scale simulations.

Table 3.2 Methods for the evaluation of potential Industrial requirements of the CSC partial-upgrading

	Method of estimating industrial scale operations	Operating conditions and requirement estimates based on:
De-salter	Related to the salt content and throughput of the bitumen feedstock	Correlation to industrial data based on calculated process unit capacity [Gary, 2001]
Topper/ATM Distillation and Furnace	Configuration and operation of trays, reboiler, condenser, reflux drums, pump arounds etc. based on modeling for crude oil properties, desired separation and throughput.	Detailed modeling based on Aspen HYSYS® engineering simulation software based on calculated process unit capacity [AspenTech, 2011]
Vacuum Dist. and Furnace	Vacuum distillation and furnace has similar design specifications as topper/atmospheric distillation, above.	Detailed modeling based on Aspen HYSYS® engineering simulation software based on calculated process unit capacity [AspenTech, 2011]
Catalyst Prep VGO/DAO	Evaluation limited to pilot plant assessment of ultra-dispersed catalyst preparation and industrial processing performance is unknown. Assumed emissions based on industry estimates for a similar process unit	Correlated to industrial data by Arthur D'Little based on calculated process unit capacity [Pereira-Almao, 2012]
CSC Upgrading of VGO/DAO	Evaluation limited to pilot plant assessment of CSC Upgrading trials and industrial processing performance effects are unknown. Assumed emissions based on industry estimates for a similar process unit: a Visbreaker plus gas oil recovery unit	Catalyst and steam based on pilot plant data. Power, fuel, cooling water and make-up water correlated to industrial estimates by Arthur D'Little based on process unit capacity [Pereira-Almao, 2012]
SDA	Design specifications estimation related to throughput. Multiple solvents with varied quality and quantity of product yield could be employed with SDA.	Correlations to industrial data by Gary and Handwerk and Arthur D'Little based on calculated process unit capacity [Gary, 2001 ,Pereira-Almao, 2012]
Amine gas Treatment	Related to the carbon dioxide and hydrogen sulphide content of the produced gas during upgrading	Industrial correlation based on pilot plant off-gas [Gary, 2001]
Sulphur Recovery	Related to the hydrogen sulphide content of the produced gas during upgrading	Industrial correlation based on pilot plant off-gas [Gary, 2001]
Cooling Water System	Estimates based on cumulative industrial scale plant requirements based on the other process units	Industrial correlation to total plant requirements [Gary, 2001]
Steam System	Estimates based on cumulative industrial scale plant requirements based on the other process units	Industrial correlation to total plant requirements [Gary, 2001]

The primary process units which are assumed to have input requirements directly adaptable from literature values include the de-salter, solvent de-asphalting (SDA), amine gas treatment, sulphur recovery, cooling water system and steam system. Process requirement estimates are assumed to be representative of literature established correlations for steam, cooling water, electricity, fuel gas and water make-up due to extensively use in these types of process units in the oil and gas industry. For example, the de-salter process requirements are correlated to base case, high and low impact estimates for electricity of 0.015 kWh/bbl, 0.020 kWh/bbl and 0.010 kWh/bbl and make-up water of 0.008 m^3/bbl, 0.012 m^3/bbl and 0.004 m^3/bbl, respectively [Gary, 2001]. The base case estimates adapted from literature are used with an uncertainty in the performance range, as calculated through high and low impact estimates which are intended to be indicative of potential process optimization or system inefficiencies. These ranges of high and low impact estimates are either directly taken from literature estimates by Gary and Handwerk, discussed further in this chapter or a 25% error range is assumed from base case estimates.

The process requirements for the catalyst preparation and the CSC upgrader process units are assumed based on industrial scaling of applicable pilot plant data or on industrial data of a similar type of process unit that is currently employed industrially. As previously mentioned, steam and catalyst requirements are main processing conditions which are assumed to be scalable from pilot plant conditions [Maya-Yesca, 2006]. For electricity, fuel and cooling water requirements, a Visbreaker and Gas Oil Recovery unit is selected as the representative process unit for assessing process requirements of the CSC upgrader process unit due to operational pressure, temperature, space velocity and feed properties which are analogous with both CSC and Visbreaking [personal communication Pedro Pereira].

Overall plant process requirements are then assessed for environmental impact through use of established emissions intensity factors. This study relies on the emissions intensity factors established by previous LCA literature for related processes. Emissions estimates are related to the production and associated upstream processing of required materials, such as catalysts, or it can be the output emissions, such as natural gas combustion. Life cycle based software, such as GREET, is used for emissions estimates such as electricity generation emissions intensity and emissions from natural gas industrial boilers [Argonne National Laboratory, 2012]. Upstream emissions related to process requirements for the catalyst requirements are taken from relevant life cycle studies such as a Nickel base metal refining study from Forbes et al. [Forbes, 2000]. Upstream emissions for the catalyst are based on environmental assessments of mining and base metal processing. The emissions intensity factors used for this study are discussed further in Section 3.5.

3.4 Calculation of Process Requirements

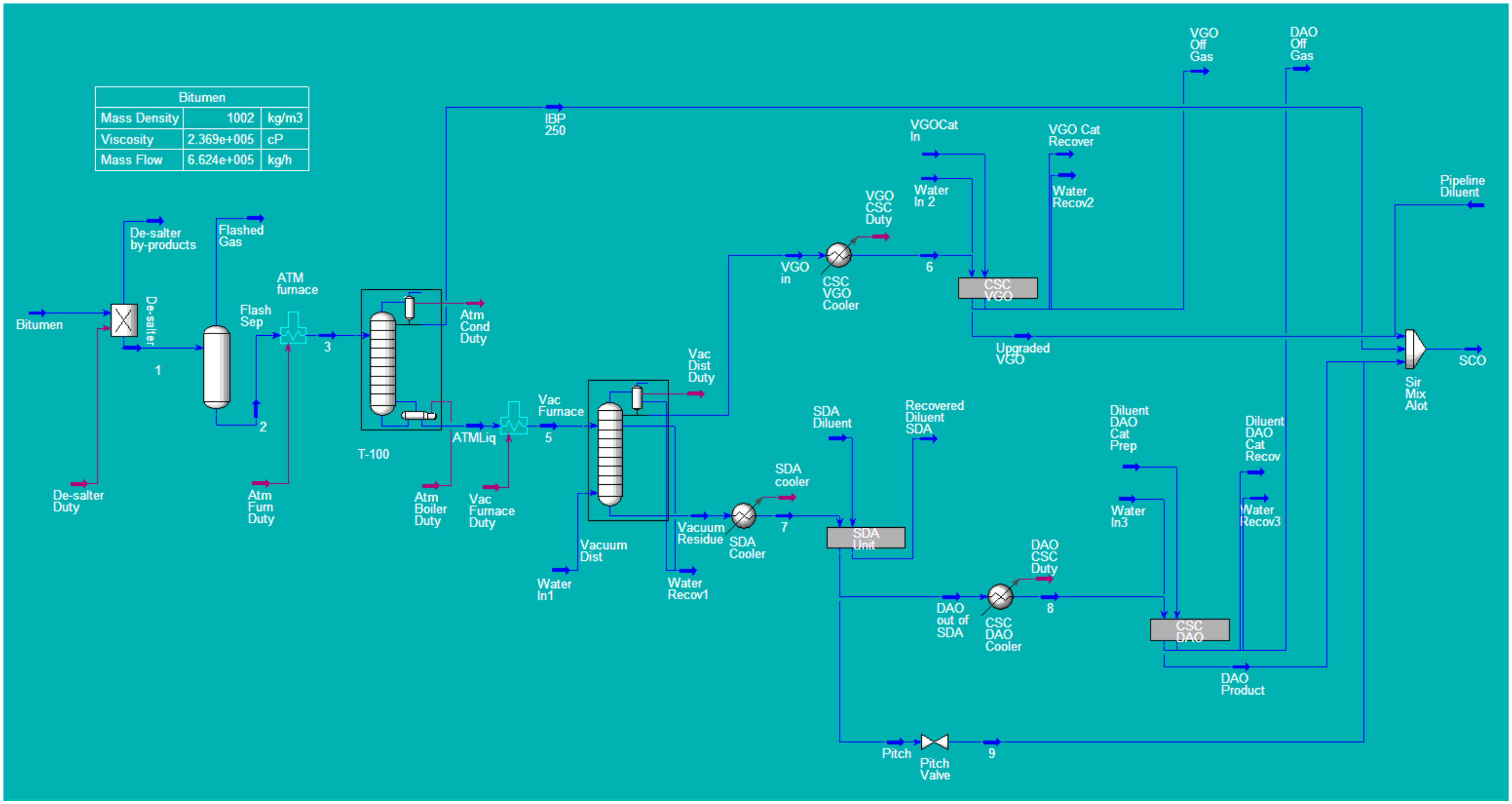
3.4.1 Aspen HYSYS® Upgrader Simulation

Aspen HYSYS® simulation software V.7.3 is used to model the crude oils, such as the Athabasca bitumen and the naphtha diluent, based on the pilot plant analysis, using crude characteristics such as boiling point and elemental composition, from Chapter 2. The fluid package, containing calculation methods and components such as water and methane, used for this simulation is Peng Robinson. The use the oil modeling environment allows for the entire crude to be represented by various fractions, referred to as pseudo-components, which allow for modeling of separation processes that result in relative volume and crude oil properties that are reflective of the actual processing of the crude oil if performed at an industrial scale. For the purpose of this analysis, bulk properties such as molecular weight, API gravity, viscosity, the boiling point characteristics based on pilot plant characterization of the crude, found in Chapter 2, are used to represent the bitumen with 40 pseudo-components. This feature is essential in verifying the mass balance from process units and the characterization of the streams throughout the Aspen HYSYS® simulation. For example, the volume and properties of the distillate products from the atmospheric distillation tower and the vacuum distillation tower are representative of the characterized 'light' and VGO fractions, respectively, from the pilot plant study in Chapter 2. Through accurate modeling of the crude oil throughout the CSC partial-upgrading process, operational requirements are directly relate to specific oil properties such as heat capacity as well as allowing for characterization of properties and compositions of different oil fractions throughout the Aspen HYSYS® modeled CSC partial-upgrading process. The model is used to estimate industrial process requirements, such as electricity and fuel, as well as sizing and configuration of process units designed for the specific crude. Figure 3.2 shows a screenshot from the Aspen HYSYS® simulation used for the assessment of CSC partial-upgrading.

The distillation units are modeled for the relative performance of the furnace, reboilers, condensers and output stream qualities. The input properties, for temperature, pressure, and composition, of crude oil fractions are linked to the specific process units from preceding units. Process unit integration is crucial in process requirement estimations due to input properties significantly affecting the distillation operations and performances such as the reflux rate as well as the temperature and pressure profile of the columns. This analysis of the distillation units uses various configurations, such as number of trays and input feed position, as well as crude conditions, such as feed temperature and pressure during process simulations.

The design of these process units is based on the desired bottoms product rate, as defined by the boiling point cuts in the CSC partial-upgrading. For example, the bottom product rate for the atmospheric distillation unit is calculated to be the total volumes of the VGO, DAO and pitch fractions which ensured only the light faction ($250^{o}C^{-}$) is distilled. Similarly, the bottoms product rate for the vacuum distillation unit is calculated to be the total volume of the DAO and pitch streams. In the base case of this Aspen HYSYS® simulation, the design of the atmospheric distillation tower included 10 trays with the heated input feed to the second tray from the bottom. The tower design also included a condenser and reboiler but did not include any side draws or pump-arounds. The simulation for this distillation towers required a reboiler to achieve the desirable bottoms product rate however expert consultation suggested that the design for the tower could have omitted this feature [personal communication with Pedro Pereira]. The design of the vacuum distillation tower included 8 trays with the input feed to the third tray from the bottom. This tower also included the use of a condenser and did not include pump-arounds. More extensive modeling and analysis of the tower design than here afforded with various configurations could be explored to identify design effects and improve energy efficiencies.

Figure 3.2 Screenshot from Aspen HYSYS® simulation of the CSC partial-upgrading



The modeled furnace duties are reflective of the energy required to heat the crude prior to entering the tower. The base case furnace duties are established based on preheating to a temperature 10^{o}C below the desired distillation cutpoint, which is typical in industrial scale operations [Pereira-Almao, 2012]. The temperature of the bitumen entering the upgrading plant significantly affects the performance and duty requirements of the furnace of the atmospheric distillation tower as can be seen in the high and low impact process requirements in Table 3.3.

The range of duties estimated with the Aspen HYSYS® simulation of the upgrader plant operation at 100,000 bbl/day and 92,000 bbl/day for the atmospheric tower and vacuum distillation tower, respectively. Base case estimates for the duty of the atmospheric distillation tower and furnace is simulated to be 5,144 GJ/day and 3,035 GJ/day, respectively. The base case estimates for the duty of the vacuum distillation tower and furnace are simulated to be 7,683 GJ/day and 555 GJ/day, respectively. The range of operational requirements from the Aspen HYSYS® assessment, based on varied process unit configurations and input conditions, is used in representing the high and low impact of various process units. The operational range is reflective of varied temperature of the bitumen entering the facility, from 0^{o}C to 100^{o}C, and varied tower configurations, included 5 to 15 trays. Table 3.3 summarizes the range of estimates obtained from the Aspen HYSYS® simulation.

Table 3.3 Process unit duty requirements for a 100,000 bpd CSC partial-upgrading plant based on an Aspen HYSYS® modeling simulation

	Base Case	Low impact	High impact
Atmospheric Furnace	3,035 GJ/day	1,006 GJ/day	6,280 GJ/day
Atmospheric Distillation tower	5,144 GJ/day	3,794 GJ/day	5,818 GJ/day
Vacuum Furnace	555 GJ/day	291 GJ/day	1,159 GJ/day
Vacuum Distillation tower	7,683 GJ/day	5,683 GJ/day	8,783 GJ/day

Duty or energy requirements from the Aspen HYSYS® model are allocated to process requirements, such as electricity, based on literature data for distillation tower operations. With use of industrial operational correlations from Gary and Handwerk, the duty requirements determined by the Aspen HYSYS® simulation are allocated to meet industrial estimates for electricity, steam and cooling water process requirements based on industrial correlations from Gary and Handwerk [Gary, 2001]. For example, all duty requirements for the furnaces are assumed to be met by fuel and whereas duty requirements for the distillation towers are divided amongst power, steam, cooling water and fuel in the same energy content proportions as industrial correlations from Gary and Handwerk. The specific process requirement breakdown of the modeled duty requirements for the furnaces and distillation units can be seen in Table 3.4, later in this section.

3.4.2 Literature Estimating Industrial Scale Implementation

This study estimates process unit utilities and material requirements using literature correlations to process unit capacity, produced gas (established from the pilot plant investigation), required amine solution, and overall plant process steam and cooling water requirements; as calculated for the CSC partial-upgrading process and respective process mass/volume flows. CSC partial-upgrading process material flow calculation is correlated with the process requirements for the base case. When a range of process requirements, based on the calculated material flows, are not specified in literature, a twenty five percent deviation is used to identify high and low requirements from the base case requirements specified to represent anticipated performance variability.

Main operating conditions from the pilot plant study, such as required catalysts and steam requirements for the CSC upgrading reaction, are assumed to be directly scaled for representing industrial scale process requirements [Ancheyta, 2011. Maya-Yesca, 2006].The low impact estimate of the steam requirements of the upgrading unit assumes steam loss is negligible and is therefore directly scaled from the steam requirements from the pilot plant evaluation. This estimate assumes steam requirements of five and four weight percent of the total processed feed to the CSC upgrading of VGO and DAO, respectively. For the base case steam requirements, the process requirements of the pilot plant evaluation are doubled to account for losses, system inefficiencies and the uncertainty in scaling up the process unit. The high case is assumed to be a twenty five percent increase in steam requirements compared with the base case assumption.

The off-gas from the CSC upgrader process unit undergoes amine gas treatment and it is assumed that the carbon dioxide and hydrogen sulphide will be completely removed for the upgrading product gas stream. Based on the gas chromatography analysis obtained during pilot plant evaluation (shown in Appendix E), it is assumed that produced gas streams from CSC upgrading of VGO and DAO have weight percentages of 5% and 7% of carbon dioxide and 0.1% and 0.2% of hydrogen sulphide, respectively. Therefore, the assumed net weight of the usable hydrocarbon off-gases produced daily would be approximately 623 and 655 tonnes produced from VGO and DAO upgrading respectively. The remaining off-gas is then assumed to either be directly used in place of natural gas fuel, thereby reducing fuel requirements, or flared [Charpentier, 2009].

The assumption that the sweetened off-gas (from amine gas treatment) could be used directly in place of natural gas fuel considers that the gas is of similar quality, as represented by energy content and composition, as well as having similar combustion emissions. Therefore, to determine GHG emissions in the low impact and base case scenarios it is assumed the required fuel for CSC partial-upgrading is in part offset with the produced off-gas stream which is assigned equivalent emissions to natural gas combustion emissions. Therefore, GHG emissions associated with the off-gas represent only emissions produced with the off-gas during upgrading for the low and base case scenarios. The combustion of this off-gas to meet plant fuel requirements is included in the fuel category for GHG calculation. The high impact estimate for produced gases assumes this off-gas stream would be completely flared and natural gas would be used to satisfy all fuel requirements. For this assumption, natural gas combustion GHG emissions are again assumed for the flared off-gas and these emissions are categorized in the flaring/off-gas GHG impacts found later in Table 3.5.

Catalyst preparation up-scaling comes with some uncertainty due to the novelty of the process, however it combines simple equipment and performs a suite of conventional physical and chemical process such as mixing and dispersed solids decomposition at very low composition using well known and scalable static mixers. This uncertainty is not only due to unknown scaling effects of process requirements but also unknowns about integration effects of this process unit with the CSC upgrading process unit. Due to the significant design requirement differences for these batch-processing pilot plant units in comparison with an integrated, on-stream process in an upgrading plant, there is some uncertainty in predict scaling up effects on catalyst concentrations/quality or upgrading performance. The high and low impact estimates included in the findings in Table 3.2 are intended to be representative of this uncertainty. For more info on how these estimates are developed refer to Section 3.3, Methods. For this reason, industry consultation with respect to modelling this process unit is required. Process unit requirements in the industry scaled model of electricity, steam, cooling water, and fuel are assumed to be five percent of the CSC upgrading unit [Personal communication with Pedro Pereira] and the catalyst requirements are directly taken from the pilot plant evaluation. By direct up-scaling of catalyst requirements based on pilot plant requirements and assuming one time catalyst use (no recycling), it is found that approximately 8.9 tonnes (t) of Ni and K catalysts per day would be required for CSC conversion of DAO and VGO streams based on this industrial scale simulation. It is assumed that process requirements for catalyst separation after CSC upgrading would be represented under the CSC process requirements and the removed catalysts would not be recycled [personal communication Pedro Pereira]. This analysis assumes the low and high catalyst requirements are based on a twenty five percent deviation from the required catalyst content of the pilot plant study.

Table 3.4 outlines the industrial process unit requirements for a 100,000 bpd CSC partial-upgrading plant based on correlation, to process unit capacities or material streams, from literature described in Section 3.3.

The process unit requirement analysis found that the distillation process (both atmospheric and vacuum towers and furnaces), SDA and CSC upgrading have the highest requirements for electricity, steam, cooling water and fuel. The remaining process units, such as de-salting and off-gas treatment, has a relatively minor impact on the overall plant requirements.

Table 3.4 Industrial process unit requirements for a 100,000 bpd CSC partial-upgrading plant

	BPD	Power (kWh/d)			Steam (kg/d)			Cooling Water (m^3/d)			Fuel (GJ/d)			Make-up Water (m^3/d)		
		Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High
De-salter	100,000	1,500	1,000	2,000	-	-	-	-	-	-	-	-	-	800	600	1000
ATM Furnace	100,000	-	-	-	-	-	-	-	-	-	3,035	1,006	6,280	-	-	-
ATM Distillation	100,000	97,222	48,611	194,444	429,185	214,592	858,369	58,000	29,000	87,000	3,794	2,444	4,469	-	-	-
Vac Furnace	92,000	-	-	-	-	-	-	-	-	-	555	291	1,159	-	-	-
Vac Distillation	92,000	27,778	13,889	41,667	429,185	214,592	643,777	52,440	39,330	65,550	6,583	5,683	8,233	-	-	-
Catalyst Prep VGO	43,620	1,025	769	1,281	31,241	15,621	39,051	2,229	1,672	2,786	209	157	261	13	10	16
CSC VGO	43,620	20,501	15,376	25,627	624,821	312,411	781,026	44,582	33,437	55,728	4,176	3,132	5,221	264	198	330
SDA	48,390	120,975	90,731	151,219	526,785	395,088	658,481	5,495	4,121	6,869	6,178	4,633	7,722	-	-	-
Catalyst Prep DAO	39,130	920	690	1,149	26,392	13,196	27,712	2,000	1,500	2,500	187	140	234	12	9	15
CSC DAO	39,130	18,391	13,793	22,989	527,839	263,919	554,231	39,993	29,995	49,992	3,747	2,810	4,683	237	178	296
Amine gas Treatment		4,588	3,441	5,734	-	-	-	7,641	5,731	9,551	484	363	605	-	-	-
Sulphur Recovery		242	242	242	7,021	5,266	8,776	7	7	7	-	-	-	7	5	9
Subtotal		**293,142**	**188,542**	**446,353**	**2,602,468**	**1,434,685**	**3,571,423**	**212,388**	**144,793**	**279,983**	**28,948**	**20,660**	**38,867**	**1,334**	**1,001**	**1,668**
Cooling Water System		23,378	17,533	29,222	-	-	-	-	-	-	-	-	-	10,619	7,964	13,274
Steam System		-	-	-	-	-	-	-	-	-	9,080	6,810	11,350	325	244	406
Off-Gas Produced	(1,362 T/d)										(-6,438)	(-8,238)	(8,238)			
	Total	**316,520**	**206,075**	**475,575**							**38,028**	**27,470**	**50,217**	**12,278**	**9,209**	**15,348**

3.5 Emissions Estimates for CSC Partial-Upgrading

Emissions calculations are performed by relating process requirements, such as electricity or fuel, to emissions output to air, water or land. These emissions are related to the upstream life cycle (extraction, processing, etc.) associated with the process requirements and are calculated by applying literature established emissions intensity factors. The emissions intensity factors, discussed in this section, are applied in accordance with industry verified emissions assessments studies or tools, such as Alberta grid emissions intensity statistics from Environment Canada and the Economic Input Output Life Cycle Assessment Model [Environment Canada, 2010. Green Design Institute, 2012]. This study compares GHG emissions, where greenhouse gas equivalent measurements are calculated based on 2007 IPCC global warming potential (GWP) for the relative heat a gas traps in the atmosphere over a 100 year interval in comparison with CO_2 [Working Group I, 2013]. A measure of Carbon Dioxide equivalent (CO_2e) is calculated for CO_2, CO, CH_4, N_2O and chlorofluorocarbons (CFC) [Working Group I, 2013].

Assumptions for fulfilling process requirements, such as the source of the electricity, with different energy systems or processes can have significant effects on the life cycle emissions. For example, the assumption of coal fired power plants for producing electricity would cause this process evaluation to have higher associate upstream emissions in comparison with the evaluation of these processes assuming electricity is produced using natural gas. For this reason, the study assumes the same energy systems as are selected for assessing the other oil sands pathways as part of the integrated LCA model, presented in Chapter 4.

In the base case, we assume the use of the Alberta grid electricity for meeting electricity requirements and fuel energy requirements supplied using natural gas boilers. Additionally, this study does not consider the use of any carbon capture technologies. Therefore, an electricity grid emissions intensity average is assumed to be 841 g CO_2e per kilowatt hour based on 2010 data for Alberta [Environment Canada, 2010]. The combustion emissions for the natural gas used to supply heat with utility boilers is 57 gCO_2e/MJ with 9.9 gCO_2e/MJ upstream emissions for production of the natural gas, based on GREET emissions factors [Argonne National Laboratory, 2012].

No life cycle studies pertaining to specialized catalyst preparation methods could be found, particularly life cycle studies related to the upstream production of chemical species such as for

Nickel Sulphate and Potassium Hydroxide. Additionally, CSC partial-upgrading could potentially use a different catalysts from the ones presented and used in the pilot plant evaluation. Therefore, literature emissions estimates which are representative of extraction and processing stages required to produce the metals are assumed to be representative of upstream emissions for producing the catalysts.

There are relevant studies published and inventory databases pertaining to the mining and refining of nickel which can be assumed for upstream impacts of the nickel catalyst production for CSC partial-upgrading [Forbes, 2000. Green Design Institute, 2012. PRé Consultants, 2013]. Limited or generic upstream emissions estimates pertaining to potassium, such as estimates for 'other non-metallic metal mining' in the Economic Input-Output Life Cycle Assessment (EIO-LCA) tool [Green Design Institute, 2012], are not found to be representative of both mining and processing of the potassium for this CSC partial-upgrading process. In the case of this evaluation, relevant nickel upstream GHG estimates are assumed as a proxy for the emissions associated with producing the required catalysts.

The upstream GHG emissions associated with the nickel catalyst required accounting for both mining and refining. The mining emissions are estimated using an Economic Input-Output Life Cycle Assessment (EIO-LCA) tool developed at Carnegie Mellon University [Green Design Institute, 2012]. This tool, which can be used to estimate the supply chain effects across different sectors, is used to estimate the emissions impact of nickel mining, with respect to a specified economic value, using the 2002 US model. With an estimated nickel price of fifteen thousand dollars per tonne (based on the approximate 2002 price of nickel derived from the 2005 price of nickel from King and the Statistics Canada's historical consumer price Index [King, 2005. Statistics Canada, 2011]) is assumed for calculating the mining emissions of 22 tonnes of GHG per tonne of nickel.

A base metal refining environmental assessment is used to estimate emissions related to refining of the nickel [Forbes, 2000]. This study by Forbes et al. assumed all process emissions are allocated to the production of nickel, however, nickel accounted for 70 weight percent of the produced metals in the case of their evaluation. Due to a lack of information regarding the other products in the Forbes study, emissions impacts determined from the Forbes study are assumed to be directly representative of upstream refining emissions for the nickel catalysts used in this study. The Forbes study assumed that emissions from the base metal refining are approximately 228 tonnes of GHG per tonne of Nickel product. Therefore, this study assumes upstream emissions associated with the catalysts are assumed to be 250 tonnes of GHG per tonne of catalysts.

The process unit energy and material requirements are used to calculate GHG using emissions intensity factors. Based on the operating requirements of a 100,000 bbl/day CSC partial-upgrading plant shown in Table 3.4, Table 3.5 summarizes the GHG emissions estimates in terms of tonnes of GHG per day associated with process electricity, fuel, catalyst and flared or off-gas products. The emissions estimates are displayed in terms of base case estimates as well as the high and low impacts which are intended to capture potential performance ranges of operation.

Table 3.5 Calculated emissions for operation of a 100,000 bpd CSC partial-upgrading plant (tonnes of CO_2e/day)

	Base Case	Low impact	High impact
AB Electricity	270	170	400
Fuel for industrial boilers	2530	1830	3890
Catalyst	250	190	310
Flaring / Off-gas	0.4	0.3	370
Total (CO_2e tonnes / day)	**3,100**	**2,200**	**5,000**

With the breakdown of emissions found in Table 3.5, the impact of the CSC partial-upgrading is estimated for the base case as 3.1 kilotonnes of GHG emissions per day with high and low impact scenarios of 5.0 and 2.2 kilotonnes of GHG emissions per day, respectively.

The operator decision regarding the inclusion or rejection of the pitch from the CSC partial-SCO, as discussed in detail in Chapter 2, is assumed to have a negligible effect on the overall plant operational emissions due to the same technologies and process units being used in both cases. For this reason, the emissions for CSC partial-upgrading with and without the inclusion of pitch are not differentiated when looking at the overall plant emissions or emissions per barrel of bitumen processed. However, emissions associated with the transport and refining of the upgraded products vary significantly between the two processes due to the difference in volume of product (CSC partial-upgrading with pitch included produced approximately 95,000 bbl of partial-SCO compared with approximately 85,000 bbl of partial-SCO when pitch is not included). The life cycle emissions impacts and economic implications of the decision to include or not include pitch in the CSC partial-SCO, as well as comparison with full-upgrading and dilution pathways, are explored further with life cycle GHG emissions characterization in Chapter 4.

3.6 Capital and Operations and Maintenance Cost Estimates

Quantifying the impacts of industrial scale deployment for emerging oil sands pathways is important due to oil sands investment typically being on the order of billions of dollars. These energy infrastructure investment decisions and highly volatile market conditions not only affect the economic competitiveness of oil sands pathways such as CSC partial-upgrading but also Alberta's wealth, with respect to taxes and royalties, and therefore are under scrutiny from government and policy makers due to the long lifetime of these energy-systems investments decisions. This section presents a preliminary assessment of capital costs and annual operations and maintenance costs to inform further economic evaluations of this energy system investment choice.

Capital cost and operations and maintenance costs estimates are primarily based on estimate for industrial processing by Gary and Handwerk, and Arthur D'Little and were calculated using Microsoft Excel® [Gary, 2001. Pereira Almao, 2011]. Capital costs are estimated based on process unit capacity (correlated to bpd process capacity), flu gas production (produced gases during upgrading), and cumulative plant steam and cooling water requirements. The capital costs are calculated for the de-salter, distillation towers and furnaces, amine gas treatment, sulphur recovery, cooling water system, steam system and two week storage facilities. Based on the subtotal of the above mentioned process units, off-site costs of 30% are assumed for this pathway. The use of contingency and location inflation factors in the estimate of capital cost is to reflect the uncertainty and increased cost of operation in Northern Alberta. A 1.5 location factor is used by McKellar et al. and a 25% contingency factor from Gary and Handwerk are assumed for this study [McKellar, 2010. Gary, 2001]. Due to the simplifications in the design and function of the small scale topper/atmospheric distillation unit, capital cost for this process unit is assumed to cost one third of the cost of a typical atmospheric distillation tower of the same capacity [personal communication with Pedro Pereira]. Similar to the assumption used in estimating processing requirements of the CSC unit as reflective of the Visbreaker and gas oil recovery units modeled by A. Little, the capital cost estimates for this process unit are also correlated, based on process unit capacities, to estimates for a Visbreaker unit by A. Little [Pereira-Almao, 2012]. The catalyst preparation process unit is currently a prototype at the pilot plant level and has only been evaluated on an industrial scale with confidential industry studies. Based on previous experience with a confidential industrial application study of a catalyst preparation process unit, the industrial scale application of the catalyst preparation process unit is estimated to be approximately 4 million dollars (US 2012) [personal communication with Pedro Pereira].

Annual operating and maintenance (O&M) costs are estimated by quantifying the cost of the electricity, fuel, catalyst, chemicals and make-up water consumed (make-up water process requirements plus 5% of steam and cooling water requirements) whereas insurance, plant maintenance, and miscellaneous supplies are related to the capital costs estimates for the plant (0.5%, 4.5%, and 0.15%, respectively) based on estimates by Gary and Handwerk [Gary, 2001]. The estimation of O&M costs also included assumptions for prices of 3.5$/GJ of natural gas, 7.3c/kWh for electricity and an assumed make-up water cost of 35 cents per thousand gallons of water. The number of plant staff is estimated at approximately 200 with an average annual salary of $100,000 [Centre for Energy, 2012. Gary, 2001.]. The assumed prices for Nickel and potassium are $15,000/tonne nickel and $400/tonne potassium [King, 2005. Statistics Canada, 2011]. The costs for amine solution and chemical makeup for the SDA assumed $1.69/kg amine solution, 4 cents per barrel of feed, respectively [Gary, 2011].

Table 3.6 and Table 3.7 displays the estimated capital cost and operations and maintenance costs for this partial-upgrading process at a 100,000 bpd capacity. The following capital cost estimates are inflated from the year of literature publishing to 2012 US dollars. A comparison of the effects of capital cost and operations and maintenance costs estimates on the net present value of the CSC partial-upgrading process is explored in Chapter 4.

Table 3.6 Capital Cost estimates for the 100,000 bpd CSC partial-upgrading plant

		BPD	Capital (M USD)
De-salter		100,000	$ 7
ATM Furnace		100,000	
ATM Distillation		100,000	$ 32
Vac Furnace		92,000	
Vac Distillation		92,000	$ 89
Catalyst Prep VGO		43,620	$ 4
CSC VGO		43,620	$ 134
SDA		48,390	$ 86
Catalyst Prep DAO		39,130	$ 4
CSC DAO		39,130	$ 125
Amine gas Treatment			$ 8
Sulphur Recovery			$ 10
	Subtotal		$ 498
Cooling Water System	15%		$ 75
Steam System	25%		$ 125
	Subtotal		$ 698
Storage	14 days		$ 192
	Subtotal		$ 890
Offsites	30%		$ 267
	Subtotal		$ 1,157
Contingency	25%		$ 289
Location (McKeller et al)	1.5		$ 578
		Total	**$ 2,025**

Table 3.7 Operations and maintenance cost estimates for the CSC partial-upgrading plant

	Operating Cost M USD per year
Makeup Water	$ 5
Power	$ 8
Fuel	$ 46
Catalyst and Chemicals	$ 21
Insurance (0.5% Capital)	$ 6
Maintenance (4.5 % Capital)	$ 52
Miscellaneous Supplies (0.15 % Capital)	$ 2
Plant Staff and Operators	$ 21
Total	**$ 161**

These capital cost estimates are reflective of industrial scale implementation of industrially proven process units, however, there is additional uncertainty involved with the CSC upgrader process units accounted for approximately over a third of the cost for all of the process units and steam and cooling water systems for the plant (before accounting for storage, offsites, contingency and location factors). Demonstration of the on-stream CSC upgrader and catalyst preparation process units could greatly reduce uncertainty in these capital cost estimates.

The fuel requirements and maintenance costs are found to be the largest contributors to the O&M costs. Variability in future fuel prices can therefore have a significant influence on O&M costs.

3.5 Further Discussion and Comments

This assessment assumes that characterized CSC partial-SCOs are representative of the industrial processing of CSC partial-upgrading (assuming the same crude oil feedstock). Additionally, the reaction conditions identified during the pilot plant study are assumed to be directly scaled for industrial estimates. The high and low impact assessments presented in this chapter are intended to capture further process optimization or systems inefficiencies in the process requirements and GHG emissions assessment which is reflective of some uncertainty in the scaling of reaction conditions but this study did not consider a range of partial-SCO products.

However, further development of a demonstration plant could be used to verify that the discrepancies between pilot plant operation and industrial scale processing, such as batch processing between different process units, do not significantly affect this assessment.

Aspen HYSYS® engineering software could be further utilized to model additional process units, through additional modeling of material separation or reaction kinetics, to enable process requirements to be directly reflective of the crude properties and upgrading conditions. The reaction kinetics could lead to further insight into reaction rates and product yields. A complete plant model would allow for process optimizing efforts for configuration and design such as crude heat recovery from Vacuum distillation column product to heat the crude entering the atmospheric/topping column. These configurations could affect key energy requirement as well as lead to further process integration between process units, as determined through energy systems optimization studies. The process optimization for configuration, sizing and design of process units could help in the development of an efficient demonstration plant and subsequent industrial processing facility.

This model can further enhance process analysis if reaction kinetics established for the CSC partial-upgrader are used to simulate the conversion reaction as well as further process integration analysis (such as pinch analysis methods for minimizing energy consumption) [Ebrahim, 2000]. Further development of this model could provide better information amount integration such as the effects of heat recovered from the products of the VDC to heat the atmospheric/topping column feed. These techniques would be good opportunities for future work in this area but are beyond the scope of this thesis.

The largest impact on GHG emissions is due to the distillation of the product with the atmospheric and vacuum distillation. Base case results for fuel, electricity, cooling water and steam requirements of the furnaces and towers resulted in approximately 46% of the total process GHG emissions. The model of the CSC partial-upgrading plant used pre-built atmospheric and vacuum distillation units from the Aspen HYSYS® engineering software which were modified with respect to sizing, tray numbers, etc. to be representative of the desired distillation cuts. Studying the effects of different scaling sizes and designs for this distillation process, such as a smaller furnace with a simplified topping column, could therefore impact the overall GHG emissions results.

This study found that process requirements for steam are a significant source of GHG emissions for the CSC partial-upgrading process. Base case results found the CSC upgrader process units accounted for 44% of the overall steam requirements. The overall fuel, electricity, cooling water, steam and off-gas emissions accounted for approximately 26% of the overall base case GHG emissions. However, these calculated steam requirements also represent an area of potential emissions reductions as steam requirement calculation for the base case industrial scale application are doubled compared with the pilot plant reaction requirements. If equivalent steam requirements found in the CSC pilot plant evaluations can be demonstrated for larger scale processing, such as in low impact scenario, then overall GHG emissions reduction of 5% from the base case upgrading process estimates per barrel of bitumen could be assumed (approximately 2.95 kilotonne/d vs. base case 3.10 kilotonne/d for operation of a 100,000 bpd facility)

This study found that the SDA unit is another process unit which has substantial impact on overall process requirements and GHG emissions. Base case results suggesting the SDA process unit accounts for approximately 530 tonnes of the 2,600 tonnes of the daily steam requirements, or approximately 20%. The overall fuel, electricity, cooling water and steam requirements for the SDA process unit accounted for approximately 20% of overall base case GHG emissions. The selection of the SDA unit which best suits the CSC partial-upgrading process therefore requires careful consideration since the performance and application of SDA technologies can vary significantly based on the desired quality and quantity of separation [Gary, 2001].

The current process design for CSC partial-upgrading separates and removes the catalyst after a single use. Recycling the catalyst could reduce the amount of catalysts required for CSC upgrading but would add potential energy requirements for the recycling unit. Companies such as Evonik Industries, offer services for catalyst recycling but there is little published research regarding online recycling of catalyst for continuous industrial processing [Evonik Industries, 2010]. Additionally, a paper by Umicore Precious Metal Refining suggests that the economics of catalyst recovery depends on how spent are the catalyst and the true metal content of the spent catalysts [Hageluken, 2004]. Though catalyst recycling is beyond the scope of this evaluation, it has significant potential for both reducing the economic and environmental burdens of this upgrading operation.

Decisions with respect to meeting the process unit requirements for the plant operation can have significant impact on emissions results. These energy system decisions can have significantly different energy system expenses and can be further complicated with the consideration for emissions mitigation technologies such as carbon capture technologies. The consideration for meeting process requirements with different energy systems and the potential use of carbon capture technologies can be considered future work related which could be used to better understanding the environmental impact of this oil sands pathway. This can spur future work which looks at the cost-benefit of these energy system choices to see what economical price.

Emissions associated with the refining and processing of the catalyst should be further verified upon appropriate environmental studies becoming available. Additional information pertaining to life cycle studies of the formation of the salt precursors, Nickel acetate and potassium hydroxide, used in catalyst preparation would further reduce uncertainty in the upstream emissions estimates associated with these catalysts. However, the GHG impacts of catalyst are unlikely to significantly affect overall CSC partial-upgrading process results as the upstream catalyst emissions presented in this study accounted for approximately 6% of GHG emissions. Catalyst recycling could further reduce catalyst requirements, affecting operational costs and process requirements, upon effective demonstration of the technology.

Verification of economic estimates for capital costs and O&M with industry practices and current operations is difficult due to the limited industrial application of partial-upgrading plants (as opposed to more common practice of full-upgrading plants diluting full-SCOs with bitumen to create a similar quality product to the proposed CSC partial-upgrading). Though partial-upgraders are not currently employed in the oil sands industry there have been recent indications that this trend could change. MEG energy recently announced plans to develop a demonstration partial-upgrading plant with plans to grow to industrial scale operations by 2020. MEG energy estimated capital costs of their 50,000 barrel per day partial upgrader facility at $1.5 Billon which they compared with a cost of $5 Billion dollars for a ‘typical’ full-upgrader with the same process capacity [Edmonton Journal, 2013]. However, the separation and upgrading processes that will be used for this facility will be unique from the CSC partial-upgrading pathway proposed in this study.

To allow for a more direct comparison of capital costs estimates, these partial-upgraders need to be compared assuming a common processing capacity. To account for the difference in facility capacities between the proposed plant by MEG energy and this study, the capital cost for a 100,000 bpd partial upgrader can be estimated based on the 50,000 bpd facility by multiplying the $1.5B capital costs by the relative capacity difference (100,000 bpd / 50,000 bpd) with the cost escalation exponent of 0.7 [Pereira-Almao, 2012]. Assuming a cost escalation factor of 0.7, the estimated capital cost for a 100,000 bpd partial upgrading facility from MEG energy would be $2.4B. This capital cost estimate is close to $2.0B estimated in this study considering these facilities will likely use different process units and conversion technologies. In comparison with MEG energy's estimates for a partial-upgrading facility, the capital cost estimate of $1.5 B for a 50,000 bpd facility is found to be in a comparable range, assuming cost escalation for the difference in processing capacity, to the capital costs in this study.

The cost estimates for typical full-upgraders vary significantly between sources and with respect to process capacity. A Jacobs study reported typical full-upgrader costs are on the order of $5 to $10 billion while Suncor announced the Voyager upgrader project cost an estimated $11.6 billion capital cost for the 200,000 bpd full-upgrader [Jacobs, 2009. OGJ Editors, 2013]. These capital cost estimates are significantly higher than estimates for CSC partial-upgrading developed in this study, at approximately $2 billion for a 100,000 bpd capacity plant, however, further consideration of the value of the upgraded product, operational requirements, forecasted price, emissions taxes as well as factors such as construction schedule and project lifetime should all be considered when compiling a thorough techno-economic assessment. The cost benefit-framework for assessing these energy systems investment decisions, including a sensitivity analysis capital and O&M costs with respect to the CSC partial-upgrading pathway value, is found in Chapter 4.

3.7 Conclusions

Through use of engineering simulations modeling and industrial data, the process unit specific energy and material requirements are calculated for the industrial scale implementation of a 100,000 bpd CSC partial-upgrading plant. Through use of established emissions intensity factors, the GHG emissions impact of the CSC partial-upgrading process requirement are calculated. The base case estimate for the industrial application of this upgrading pathway for the processing of 100,000 barrels of bitumen per day is calculated to be approximately 3,100 tonnes of GHG emissions per day, with high and low impact analysis of 5,000 and 2,200 tonnes of GHG emissions per day respectively. The variance in these scenarios, with the high case approximately double the emissions of the low impact case, is reflective of the uncertainty in estimating the industrial scale impacts of this process currently being developed at the pilot plant level. This range can be reduced by further verification of operational requirements at the demonstration level.

Identifying significant sources of energy and process requirements for this CSC partial-upgrader is used to inform further process development. Based on the modeling of this process unit at industrial operations level, the performance of the CSC upgrading units were determined to account for approximate 26% of the total process emissions. With the development of these CSC upgrading process unit, this study has identified the required steam as the most critical process requirement, as they accounts for nearly half of the total steam requirements of the process based on this assessment. Distillation and SDA represent other process units with significant process requirements which accounted for approximately 46% and 20% of the calculated total process GHG emissions, respectively.

This chapter also estimates capital costs, and annually O&M expense estimates for the CSC partial-upgrader to be approximately $2 billion and $161 million, respectively. These economic estimates are developed for use in the economic framework developed for assessing investment value of this partial-upgrading pathway in comparison with dilution and full-upgrading pathways over the lifetime operation of these energy system choices, found in Chapter 4.

The effects of these emissions impacts will be assessed in terms of the developed GHG environmental and economic comparison of investment values, found in Chapter 4. The development of a WTW emissions model allows for the direct comparison of GHG emissions of the CSC partial-upgrading process with full-upgrading and dilution pathways through accounting for downstream processing impacts of the upgrading or dilution processes. The techno-economic comparison of oil sands investment options allows for direct comparisons of the pathways through inclusion of capital, and O&M costs established in this chapter as well as future crude pricing markets, royalties, income taxes and consideration for carbon emissions policies.

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4.0 Oil Sands Pathway Comparison for CSC Partial-Upgrading

The use of life cycle assessment (LCA) in assessing the environmental impacts of industrial processes is becoming more prevalent with environmental legislation, which can complicate investment decisions [Bergerson, 2012]. Therefore, careful consideration of environmental costs and current or future legislation is necessary to better inform these types of energy systems infrastructure investments decisions.

This chapter addresses the framework for assessing well-to-wheel (WTW) GHG emissions for the CSC partial-upgrading pathway to account for upstream and downstream processing of the crude oil and the final product slate. The calculated industrial scale GHG emissions impacts of the CSC partial-upgrader, from Chapter 3, are used as a partial-upgrader model. This model also uses the characterized CSC partial-SCOs, from Chapter 2, to represent the CSC products as part of the integrated WTW GHG emissions model for oil sands pathways. Comparison with emissions estimates via established models for full-upgrading and dilution pathways, previously developed as part of the integrated LCA models, are used to explore carbon based policy implications of these processes. A case study for a partial cost-benefit analysis of these respective pathways is used to further inform the investment value of these pathway options for oil sands development projects.

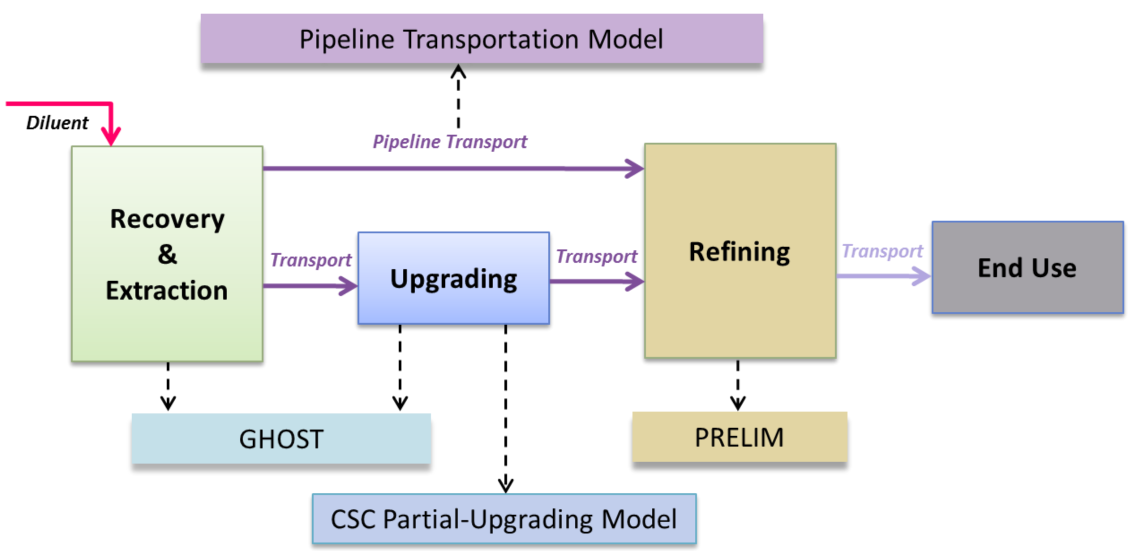
4.1 Introduction

The recent development of North American climate change policies based on LCA emissions calculations, such as the low carbon fuel standards (LCFS) implemented in British Columbia and California, and non-life cycle based emissions calculations, such as the industry specified gas emitters regulation (SGER) of Alberta, have had obfuscating effects on future growth of the oil sands. The differences between the GHG emissions evaluation method for these policies is indicative of different regulating bodies' and jurisdictions. The LCFS, which regulates the transportation fuels that are sold in these markets, assesses emissions impacts of producing the fuel product. The SGER, which regulates high-emitting facilities, accounts for all Alberta based operations, such as bitumen extraction and upgrading. For this reason, the LCFS mandated approach for LCA emissions calculations for fuel products often differs from the approach used to evaluated emissions for other types of emissions policies such as the SGER.

The GHG emissions impacts analysis detailed in this chapter further expands upon the LCA models developed at the University of Calgary and University of Toronto for the WTW assessments of oil sands products based on engineering principals and industry data [Charpentier, 2011. Abella, 2012. Choquette-Levy, 2013]. The projected industrial impacts of the CSC partial-upgrader are used as a CSC partial-upgrading model which, along with crude properties determined through the pilot plant study, is used to represent the CSC partial-upgrading pathways in the established LCA model. The integrated oil sands pathway models capture the effects of the CSC partial-upgrading on downstream activities such as refining, allowing for a complete WTW emissions characterization of dilution and full-upgrading pathways already in the model.

This integrated WTW LCA model is developed by linking various stage specific evaluation models through crude properties such as density and mass flow. Figure 4.1 shows the various models and how they are integrated.

Figure 4.1 Oil sands life cycle assessment emissions model



The first model developed as part of this integrated LCA model was developed by Charpentier et al. in an effort to estimate the energy and GHG emissions impact of existing extraction and upgrading operations [Charpentier, 2011]. The model, known as GHOST, assesses GHG impacts associated with extraction through surface mining, steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) techniques and full-upgrading through delayed coking and hydrocracking technologies. This extraction model produces estimates for energy and GHG emissions using operational parameters such as electricity and natural gas use, flared and fugitive emissions, and steam to oil ratio (SOR) for in-situ operation or diesel emissions for mining operations. Upgrading emissions are calculated using operational parameters such as electricity, natural gas and hydrogen use, flared and fugitive emissions and volume ratio of upgraded product to bitumen (m^3/m^3). The model also includes the option for co-generation of electricity and heat for meeting process requirements. This co-generation option is modeled after a combined cycle gas turbine and heat recovery steam generator where any surplus electricity is assumed to be usable elsewhere but does not include a GHG emissions offset.

In the case that upgrading is not performed or the partial-SCOs requires additional diluent to improve properties to meet transportation requirements, upstream emissions are calculated for the required diluent. The upstream emissions for the diluent are reflective of the production, distribution, etc. of the diluent products as intended to best reflect environmental impacts of this process requirement. The integrated LCA model assumes indirect emissions for natural gas condensate, naphtha and full-SCO diluents based on a variety of life cycle models and study estimates.

A pipeline transportation model was developed by Choquette-Levy to estimate transportation GHG emissions based on crude properties and pipeline operating characteristics [Choquette-Levy, 2013]. The model was developed based on fluid mechanics principles to account for factors such as crude density and viscosity properties for the transportation distance, pump and grid efficiencies and elevation change on route to the refinery.

The refinery model, titled PRELIM, was developed by Abella and Bergerson [Abella, 2012]. This model was developed based on mass balances between process units within a refinery scheme, similar to how emissions are estimated for the partial-upgrading model, as developed in Chapter 3. The energy and GHG emissions calculation from this model can differentiate between crude qualities as well as the effects of different refinery configurations. The PRELIM model can represent ten unique refinery configurations to assess the refining energy and GHG emissions based on particular crude oil assay. The crude oil assay includes crude characterization factors such as API, and hydrogen content. The model also includes a crude assay inventory with 30 crude assays including those for fully-upgraded oils and diluted bitumen based on publically available assays adapted from *crudemonitor.ca* and assays obtained under non-disclosure agreements from several oil sands companies [Crude Quality Inc., 2013]. PRELIM calculates material balances for each individual process unit that can be used to allocate refinery process emissions to the refinery products based on the user specified allocation method, such as with respect to energy or hydrogen content of the products. Allocation methods and functional units used for calculating pathway GHG emissions are discussed in detail in Section 4.2.2. PRELIM also has the capability to optimize the system to the end use products depending on refinery processes and market demands.

End use emissions, or combustion emissions (e.g., from burning the transportation fuel in a vehicle) are calculated using GREET emissions intensity estimates [Argonne National Laboratory, 2012]. End use emissions tend to dominate the life cycle of hydrocarbons (64-74% of total life cycle emissions for vehicle use phase [Charpentier, 2009]) and therefore the decision regarding the scope of the LCA framework, with respect to these end use products, has a significant effect on life cycle results, as shown in the GHG emissions results found later in this chapter.

The method used in the integrated LCA tool is developed for oil sands pathways, primarily on a process unit level, to allow for a transparent comparison between alternative technologies or processes, by using consistent boundaries and assumptions. Though this model is used to represent crude processing pathway throughout the life cycle, it does not exactly replicate actual operations with respect to pipeline transportation and refining. For example, pipelines transport multiple types of crudes in 'batches' based on the demands of refineries [Choquette-Levy, 2013]. Therefore, assessing pipeline transport and refinery emissions based on a single crude oil is not reflective of the actual process. However, this simplified model for single crudes is a reasonable assumption for representing the actual process if the emissions allocation methods, such as the energy content based allocation of refinery emissions to refinery products, reflect the impact of the particular crude in the batch. Further detail related to emissions allocation is discussed in the methods for life cycle comparison section of this chapter.

Cost-benefit analysis is a decision-supporting tool which can be used for comparing the revenues and expenses of different projects options [Greenberg, 1996]. The development of this cost-benefit analysis framework for informing investment decisions involved consideration for economic factors such as capital and operational costs, taxes, royalties and climate related penalties associated with differences in policies for comparing the net present value (NPV) of the oil sands projects. The inclusion of GHG emissions costs, based on the quantification of GHG emissions case study comparison of oil sands pathways with respect to current or prospective emissions policies, is then used for informing the potential economic performance of these pathways under potential emissions policies such as an economy wide carbon tax. However, differing stakeholder preferences for these oil sands pathways often stem from assumptions about future conditions, preferred rate of return on project investments, etc. The externalities of the GHG emissions assess for their impacts on the investment value of oil sands projects under various current and potential future climate policies. The sensitivity to operational factors such as crude prices is also explored.

In addition to the comparison of CSC partial-upgrading with GHG emissions estimates for full-upgrading and dilution built into the model, this study also compares emissions results against previous literature studies of oil sands operations. This comparison is used to better understand how the case study emissions results compare with previous literature results for both upgrading and dilution pathways. This study compares estimates obtained using the integrated LCA model with estimates by Jacobs™ consultancy, TIAX LLC consultancy, California Air and Resources Board (CARB) as well as Greenhouse Gas, Regulated Emissions and Energy Use in Transportation (GREET) and GHGenius models [Jacobs, 2009. TIAX, 2009. California Air and Resources Board, 2011. Argonne National Laboratory, 2012. $(S\&T)^2$ Consultants Inc., 2012.]. The Jacobs™ consultancy study, hereafter referred to as Jacobs, is a study by Keesom et al. used to compare imported crude oils to those produced in North America. The TIAX LLC consultancy, hereafter referred to as TIAX, is a study by Rosenfeld et al. used to study GHG emissions and energy use of Canadian oil sands pathways in comparison with conventional oil source pathways. GHGenius is a model developed by $(S\&T)^2$ Consultants Inc. for Natural Resources Canada which has been used to support Canadian climate change plans and investment decisions to reduce GHG emissions [$(S\&T)^2$ Consultants Inc. 2004]. GREET is a model developed by Argonne National Laboratory for the Office of Energy Efficiency and Renewable Energy and is used by US Congress and federal agencies to support GHG emissions reduction efforts, such as the legislative development of California LCFS [United States Department of Transportation, 2005]. The CARB study, hereafter referred to as CARB, estimates of WTW GHG emissions intensities used in California's LCFS for representing oil sands products which have undergone full-upgrading or dilution [California Air and Resource Board. 2011]. For comparison, the in-situ extraction plus dilution or upgrading pathways are selected from each of the above mentioned studies and models to compare with the pathways presented in this chapter which also assume in-situ recovery.

4.2 Method for Life Cycle Emissions Comparison Case Study

This section describes the comparative pathways and operational parameters of extraction, upgrading, dilution, pipeline transport, refining and end use as well as the different emissions policies and respective functional units used for calculating GHG emissions. This study assumes the same SAGD extraction method for all pathways and the calculation of GHG emissions for this pathway is based on 'case study' modeling assumptions built into the integrated LCA model. The case study model assumptions for SAGD extraction are reflective of default modeling values used to characterize an 'average' product that would result from the modeling scenario. The default modeling values used for these case study modeling scenarios are based upon literature and data collected through non-disclosure agreements with several oil sands companies and expert elicitation.

The case study allows for the comparison of the CSC partial-upgrading pathways with the case study modeling assumption for dilution and full-upgrading pathways which are established in the integrated LCA model. The integrated LCA models, including the new CSC partial-upgrading model, are developed to establish performance ranges of the industry technologies. However, this study assumes point estimates for obtaining comparative GHG emissions of the CSC process at an early stage of development and use in the cost-benefit analysis of oil sands pathways with the internalization of emissions costs, related to relevant policies.

In addition to the case study estimates, used for informing the economic comparison, a range of potential emissions are also used to calculate emissions for the pathways based on low and high GHG emissions impact parameters form the integrated LCA model. These high and low GHG emissions impact parameters were again based upon literature and data collected through non-disclosure agreements with industrial partners.

This study is used to inform the pathway GHG emissions with respect to the two current emissions policies affecting oil sands operations, SGER and LCFS, as well as potential economy wide carbon tax. The current policies represent a regional carbon regulation affecting the operations in Alberta and industry regulation, impacting sales of oil sands products to certain fuels markets. Due to the differences in how these current and a potential future economy wide carbon tax can be used to assess GHG emissions impacts of oil sands operation, these policies are explained and the functional units selected for representing the presented emissions calculations in this thesis are discussed in this methods section prior to introducing results from the integrated model.

4.2.1 GHG Emissions Policies

California's LCFS ensures transportation fuel products sold to the Californian market meets an established GHG emissions threshold which is measured in terms of CO_2e per unit energy of fuel sold (for example per MJ of gasoline) [State of California, 2006]. This 2010 implemented LCFS policy uses a market based mechanism that allows producers of fuels with emissions above this threshold to blend their product with lower GHG intensive fuels or buy credits from providers of low GHG fuels to sell in the California market [State of California, 2006]. The current emissions thresholds set in California require oil sands pathways to demonstrate that the fuel product has Well-to-Refinery (WTR) emissions under 15 g CO_2e/MJ of gasoline and WTW emissions of 95 g CO_2e/MJ of gasoline, however, the WTW emissions threshold is annually decreasing and will be 86 g CO2e/MJ gasoline by 2020 [State of California, 2006]. LCA embedded policies have also been adopted with a similar LCFS policy in British Columbia and the European Fuel Quality Directive which also use GHG emissions measurements per unit energy of transportation fuel [Province of BC, 2013. Curran, 2011].

Alberta Environment regulated SGER tax, implemented in 2007, assess GHG emissions impacts of industrial operations in Alberta (with annual GHG emissions greater than 100,000 tonnes of CO_2e/year) but does not address life cycle emissions impacts. Alberta's SGER tax imposes a \$15/tonne CO_2e for emissions above a baseline emissions threshold which is defined by a reduction from 2007 facility operational emissions or the emissions from the first year of commercial operation in the case of newer facilities (with a maximum reduction of 12%; therefore at least 88% of the facilities baseline emissions are not taxed). To relate the significance of the SGER to oil sands operations in Alberta, calculating emissions in terms of a barrel of crude oil can often be the most useful measurement. This is due to oil sands operations most commonly using barrels of bitumen as an economic and operational proxy, such as the price of West Texas Intermediate (WTI) crude oil or forecasted production levels.

The possibility of an economy-wide carbon tax in Alberta, like many European countries and Australia, may further affects future energy system investment decisions [European Commission, 2013. Australia Government, 2013]. An economy wide carbon tax is a mechanism which can be used to incentivise and promote life cycle GHG reductions. Economy wide carbon taxes can be most effective in light of a market failure, where the actions of one party affects the production or consumption of another party with no market mechanism to compensate for this action [Brown, 2011]. Due to international operations and markets for crude oil and crude oil products, an economy wide carbon tax could be used to incentivize upstream operations/processing which results in emissions reduction from downstream processing and the final product slate. For the purpose of this study and the specific relevance to an upstream decision regarding partial-upgrading, full-upgrading or dilution, the functional unit of a barrel of bitumen is again the most applicable for representing an economy wide carbon tax.

4.2.2 Functional Units of Barrel of Bitumen or Megajoule of Gasoline

The functional unit of a bbl of bitumen is used to assess the GHG impacts of extracting and processing of the crude oil resource as well as accounting for the slate of end products. Calculating process requirements and GHG emissions attributed to the production of a bbl of bitumen is most straightforward when assessing extraction processes. However, further processing of the crude oil with upgrading or dilution, transportation, refining and end product becomes more complicated due to the addition or removal of hydrocarbons, such as diluent or pitch/coke by-products. This study assumes that any diluent product added to the crude oil will be refined into the end products and therefore are calculated for additional transportation, refining and end products emissions as well as the upstream emissions related to the diluent production. This study also assumes any produced by-products during upgrading will not be further used and therefore are not assessed end use emissions. GHG emissions impacts of storage/disposal of stockpiled by-products are not address within the context of this thesis.

Emissions calculations with respect to the functional unit of a bbl of bitumen rely on the relative volume of bitumen to volume of the crude, such as a full-SCO intermediary or diesel final product. For example, assuming the same viscosity and density properties of the CSC partial-SCOs after dilution to reach minimum pipeline specifications, these two pathways would share the same transportation emissions per volume of partial-SCO product. However, the decision to remove pitch for one partial-SCO and the inclusion of pitch in the other partial-SCO cause these pathways to have difference transportation volumes. Transportation emissions per barrel of extracted bitumen are reflective of the volume of upgraded product sent to the refinery and therefore comparatively less upgraded product is transported when pitch is removed during the upgrading stage, as shown later in this chapter.

The functional unit of a MJ of gasoline is used to assess the GHG impacts of the extraction and processes required to produce the transportation fuel as well as the combustion of said transportation fuel. Calculating process requirements and GHG emissions per unit energy of gasoline product relies on allocation of process requirement and GHG emissions to a specific product from the refinery product slate. Many allocation methods have been used to attribute refinery process requirements and GHG emissions to individual products, such as energy or hydrogen content of the individual product and that of the total energy or hydrogen content of the product slate [Bredeson, 2010]. For example, assuming energy content allocation and the refining of one barrel of diluted bitumen resulting in 600 MJ of final products; of which 300 MJ are gasoline, 60 MJ are diesel, and 240 MJ are other products, then 50% of emissions would be allocated to gasoline, 10% would be allocated to diesel and the remaining 40% would be divided amongst the other products. Though some previous studies have identified that hydrogen content can be the most applicable allocation method for refinery emissions and products [Bredeson, 2010], energy content based allocation of GHG emissions is assumed when calculating emissions using a functional unit of MJ of gasoline for refining and all other upstream processing in this study.

This energy content based allocation method used for refinery emissions can easily be extended to pipeline transportation emissions, however, further upstream processing such as dilution or upgrading and the extraction of the resource again becomes complicated with the addition and removal of hydrocarbons, such as diluent or pitch/coke by-products. LCFS calculation methods address a single product and do not consider other refinery products or by-products produced at the upgrading stage. However, this policy addresses the addition of hydrocarbons for dilution through assessing upstream emissions related to diluent production. These input diluent hydrocarbon stream are accounted for in downstream transportation, refining, and in part, the composition of the transportation fuel products. Due to this calculation method used for LCFS, this study assesses the emissions impact of upstream extraction and upgrading or dilution based on the energy content ratio of the refinery product gasoline to the complete product slate.

Throughout the methods section of this chapter, GHG emissions results are expressed either in terms of a MJ of gasoline or a bbl of bitumen as the functional unit. Due to the two presented calculation methods differing in treatment of by-products and diluent, the emissions for upstream processes for extraction and upgrading are presented using a bbl of bitumen as the functional unit while downstream processes for transportation and refining are presented using a MJ of gasoline as the functional unit. The functional units selected for representing the calculations found in this methods section are intended to be presented in a manner which is most straightforward to the reader as well as to further explain how the volume ratio and energy content are used for calculating GHG emissions with respect to the respective functional units. Calculated GHG emissions using both functional units can be found in Figures 4.2 and 4.3.

4.2.3 Extraction

Due to the focus of this comparative study on the effects of upgrading or dilution choices on overall life cycle impacts, we can assume the same upstream pathways. Due to the significance of in-situ technologies for the exploitation of the remaining oil sands reserve, SAGD extraction is assumed for the extraction of the raw bitumen for all cases [Alberta Energy, 2013]. For this comparative assessment, these pathways are assumed to use the same extraction method and operating conditions.

The case study extraction emissions are calculated using the following assumptions regarding SAGD extraction. The high and low GHG emissions impact parameters from the LCA model used to estimate the performance range are found in brackets following the case study assumptions.

This extraction assumes operational parameters of 75 kWh (45 kWh, 120 kWh) of electricity, 0.7 kg GHG (0.4 kg GHG, 1.6 kg GHG) flared and fugitive emissions equivalent per meter cubed of bitumen and assumes a SOR of 2.6 (2.1, 3.3). The GHG emissions for SAGD extraction are calculated to be 69 kg CO_2e per barrel bitumen (48 kg CO_2e/bbl bitumen, 157 kg CO_2e/bbl bitumen) for all oil sands pathways.

4.2.4 Upgrading

The CSC partial-SCOs and industrial process requirement and GHG emissions are detailed in Chapters 2 and 3. For the CSC pathways, the amount of hydrocarbons which resulted in produced gas or pitch that is removed during the partial-upgrading process are summarized in Table 4.1. The emissions associated with CSC partial-upgrading are 31 kg CO_2e per barrel of extracted bitumen with high and low impact assessments of 50 and 22 kg CO_2e per barrel of bitumen. Due to the high level of uncertainty of the performance of the CSC partial-upgrading process at an industrial scale, the potential range of emissions is found to be larger than the ranges for coking and hydrocracking full-upgrading processes from the integrated LCA model.

The conditions for full-upgrading pathways are based on case study operational parameters built into the GHOST model. The high and low GHG emissions impact parameters from the LCA model used to estimate the performance range are found in brackets following the case study assumptions. The upgrading case study assumption for full-upgrading through delayed coking are a 0.85 (0.78, 0.9) volume ratio of upgraded product to Bitumen (m^3/m^3), industrial natural gas boilers, 55 kWh (40 kWh, 70 kWh) of electricity, 55 m^3 (50 m^3, 60 m^3) of required hydrogen, 7.5 kg GHG (5 kg GHG, 12 kg GHG) of flared and fugitive emissions per barrel of fully-upgraded oil. The estimates for hydrocracking full-upgrading are based on upgrading conditions such as a 1.03 volume ratio of upgraded product to Bitumen (m^3/m^3), industrial natural gas boilers, 55 kWh (40 kWh, 70 kWh) of electricity, 220 m^3 (210 m^3, 230 m^3) of required hydrogen, 7.5 kg GHG (5 kg GHG, 12 kg GHG) of flared and fugitive emissions per meter cubed of fully-upgraded oil. Case study full-upgrading emissions of 47 kg CO_2e per bbl bitumen (44 kg CO_2e per bbl bitumen, 69 kg CO_2e per bbl bitumen) are assumed for production of full-SCO oil from coking. Case study full-upgrading emissions of 57 kg CO_2e per bbl bitumen (51 kg CO_2e per bbl bitumen, 77 kg CO_2e per bbl bitumen) are assumed for production of full-SCO oil from hydrocracking.

Table 4.1 summarizes some of the key operational parameters associated with the oil sands pathway after any upgrading processing but before dilution is performed. These density characteristics are used as the basis for calculating naphtha dilution requirements for meeting pipeline requirements. The mass fractions of the liquid, gas and pitch/coke summarize the processing effect of the different pathways. For example, the extracted bitumen for the dilbit pathways is not processed and therefore remains completely as a liquid product. The effects of upgrading for the remaining pathways can be seen through calculated mass fractions of partial/full-SCO liquid product, produced gas (process gas) and pitch or coke removed at the upgrading stage.

Table 4.1 Case study assumptions for oil sands pathways after partial/full-upgrading (prior to dilution)

	Dilbit (Athabasca)	CSC partial-SCO with Pitch	CSC partial-SCO without Pitch	Coking Full-SCO	Hydrocracking Full-SCO
Density	**1012 kg/m^3**	**981 kg/m^3**	**959 kg/m^3**	**865 kg/m^3**	**865 kg/m^3**
Mass Fraction Liquid Product	**1**	**0.93**	**0.80**	**0.75**	**0.89**
Mass Fraction Process Gas	**0**	**0.07[1]**	**0.08[1]**	**0.07[2]**	**0.07[2]**
Mass Fraction of Pitch/Coke Removed	**0**	**0**	**0.12[3]**	**0.19[4]**	**0.04[4]**

The mass fraction of produced gas (process gas) during upgrading is obtained from measurements collected during pilot plant operation[1], and obtained from the integrated LCA model case study[2]. The mass fraction of pitch is assumed for the SDA technology[3] [personal communication Lante Carbognani].The mass of coke removed in the case of hydroprocessing/coking is calculated based on the model case study assumptions for volume of gas production, volume of upgraded product to diluent, density of upgraded products, and assumed density of process gas based on gas produced during pilot plant studies[4].

4.2.5 Dilution

Pipeline transportation specifications are in place to avoid wax formation or corrosion of the pipeline which can lead to restricted flow or leaks. For the purpose of this study we focus on pipeline transportation specifications set for maximum allowable densities and viscosities of crude oils. Maximum density and viscosity requirements for pipeline transportation have varied between literature sources. For example, pipeline requirements are identified as viscosities not exceeding 350 centistokes (cSt) at pipeline reference temperature (with no specified density requirements) in an Alberta Innovates report [Tsaprailis, 2013], while a TransCanada Keystone pipeline applications indicates that density and viscosities limits of 940 kg/m^3 and 350 cSt will be imposed for pipeline transportation [TransCanada, 2006]. An Enbridge operational report of the crude properties of crudes transported in 2012 [Enbridge, 2012] indicates a range of dilbit densities, at 15^{o}C, from 936 kg/m^3 to 922 kg/m^3 with the majority of dilbits densities equal or less than 930 kg/m^3. For that study a pipeline transportation density of 925 kg/m^3 is assumed and the associated viscosity at 20^{o}C is 162 cSt (316 cSt at 10^{o}C). For this study a viscosity of 155 cSt at 20^{o}C is assumed for meeting pipeline specifications. Additionally, it is assumed that the crude properties would need to meet both density and viscosity properties for pipeline transportation.

Based on the pilot plant evaluation, the CSC partial-SCOs ranged in viscosity and density from 795 cSt to 129 cSt at 20^{o}C and 981 kg/m^3 to 959 kg/m^3 at 15.5^{o}C for CSC partial-SCOs with and without the inclusion of pitch material, respectively. The viscosity and density of the Athabasca bitumen, used in the pilot plant evaluation, is 31,600 cSt at 20^{o}C and 1,013 kg/m^3 at 15.5^{o}C.

When the product itself does not meet the pipeline specifications described above, diluent is added. Naphtha (typically produced through the upgrading process) is one option for diluting bitumen and is assumed for this analysis. The diluent is used for increasing viscosity and density properties of the crudes. The properties of the naphtha are assumed for this study are based on ExxonMobil naphtha properties from the Kearl oil sands operations [ExxonMobile, 2012] including a density of 700 kg/m^3 and a viscosity of 0.39 cSt at 20^{o}C. Though the assessment of multiple diluent types is outside of the scope of this study, the oil sands industry has also adopted a range of diluent including natural gas condensate and full-SCO as diluents; which have been found to have varied effects on life cycle estimates due to different associated upstream emissions and blending ratios [Brandt, 2011].

To calculate the naphtha diluent required for meeting pipeline density requirement, the following equation is used, where V and ρ are the volume fraction and the density, respectively.

$$\rho_{min\,pipeline} = \rho_{crude} * V_{crude} + \rho_{diluent} * V_{diluent}$$

To calculate the naphtha diluent required for meeting pipeline viscosity requirement, the viscosity estimates are calculated in accordance with the Refutas Equation for the estimated viscosity from the blending of two or more liquids [Maples, 2000]. This equation calculates a viscosity blending number (VBN) for the liquids being blended and where the viscosity of the product can be determined through the addition of weight percentages multiplied by the VBN of the solutions mixing, respectively. The Refutas equation used for determining the required mass percent to reach minimum viscosity can be seen below, where v is the kinematic viscosity in cSt and x is the mass percentage.

$$VBN = 14.534 * \ln\,[ln(v + 0.8)] + 10.975$$

$$VBN_{min\,pipeline} = x_{crude} * VBN_{crude} + x_{diluent} * VBN_{diluent}$$

This study found meeting viscosity requirements results in less required dilution compared with meeting density requirements. Therefore, diluent required for meeting density specifications are assumed for the crude oils because this study assumes crudes must meet viscosity and dilution requirements for pipeline transportation. Table 4.2 shows the calculated density of the crude oils after naphtha dilution. This table also presents the mass fractions with respect to the bitumen/whole crude for consistency with the mass fractions displayed in Table 4.1. The volume ratio is calculated with respect to the mass fractions of the liquid product from upgrading and the mass fraction of diluent multiplied and the density ratio of the transportable product and Athabasca bitumen. For example, the dilbit did not undergo upgrading and is found to require 25 weight % of diluent (therefore, the mass of the dilbit is 25% greater than the mass of the original bitumen) to reach the required density of 925 kg/m^3. Using the densities of the original Athabasca bitumen, 1012 kg/m^3, it is found that the volume ratio of the bitumen to pipeline transportable dilbit is approximately 0.73.

Table 4.2 Case study assumptions from oil sands pathways after partial/full-upgrading and dilution

	Dilbit (Athabasca)	CSC partial-SCO with Pitch	CSC partial-SCO without Pitch	Coking Full-SCO	Hydrocracking Full-SCO
Density after Dilution	**925 kg/m^3**	**925 kg/m^3**	**925 kg/m^3**	**865 kg/m^3**	**865 kg/m^3**
Mass Fraction of Naphtha Diluent	**0.25**	**0.15**	**0.09**	**0**	**0**
Bitumen : Upgraded/Diluted Volume ratio	**0.73**	**0.87**	**1.02**	**1.16**	**0.96**

It should be noted that a volume ratio of 0.7 for bitumen to naphtha diluent was previously assumed as the case study in the integrated LCA model; based on industry consultation [Choquette-Levy, 2013]. The calculated volume ratio of 0.73 for the Athabasca bitumen, as determined with the viscosity and density blending calculation, confirms that these dilution calculations are within range of industrial dilution processes. The discrepancy between the determined ratio and the case study ratio in the integrated model are based on the bitumen and naphtha properties, which can vary between wells and operations. This study uses the calculated volume ratio of 0.73 for bitumen to naphtha diluent.

The estimation of required diluent in the case of this evaluation could be further verified through laboratory trials and product analysis. This test was not performed due to the small production volumes at the pilot plant scale. Further demonstration scale investigations of this process would allow for larger quantities of upgraded product, which can be used to better characterize the crude, through analysis of crude fractions, as well as experimentally verifying dilution requirements.

The upstream emissions attributed to the naphta diluent, for representation in WTW emissions, can be calculated using the volume of diluent required, transportation distance for make-up diluent, and an established GHG emissions intensity factor which is representative of the upstream life cycle of the naphtha. The case study transport distance for make-up diluent is assumed to be 500 km with low and high GHG emissions impacts representative of 100 km and 1000 km distances, respectively. GHG emissions intensity factors have been calculated to range from 0.086 to 0.76 [Argonne National Laboratory, 2012. PRé Consultants, 2013. PE International, 2012. $(S\&T)^2$ Consultants Inc., 2012] This study assumes the case study emissions intensity factor, associated with upstream production of the naphtha diluent, of 0.69 kg GHG emissions per liter of naphtha diluent based on SimaPro LCA software [PRé Consultants, 2013].

Using this emissions intensity factor for accounting for upstream dilution production, the calculated dilution requirements for the dilbit pathway found diluent contributed approximately 1.4 g CO_2e per MJ gasoline. In the case where the CSC partial-SCO did not include pitch, the upstream dilution emissions are approximately 0.8 gCO_2e/MJ gasoline. When pitch is not removed the emissions are found to be approximately 0.4 gCO_2e/MJ gasoline for the CSC partial-SCO. This study assumes no GHG emissions are applied to the full-upgrading pathways for diluent requirements as it is assumed that extraction facilities and upgraders will be in close proximity and therefore any diluent required for moving the bitumen from extraction to the upgrading facilities is assumed to be negligible for this study of GHG emissions.

4.2.6 Pipeline Transportation

Transportation emissions are calculated reflective of transportation from around the Fort McMurray area to refineries near the Chicago area (PADD 2: Midwest). This study assumes pipeline specification and transport distance as well as pump and grid efficiencies, and elevation changes which are reflective of pipeline transportation from the oil sands to refineries in the US Midwest [Choquette-Levy, 2013]. The high and low GHG emissions impact parameters from the LCA model which are used to estimate the performance range are found in brackets following the case study assumptions. This study assumes a transportation distance of 3,000 km (2,000 km, 4,500 km), net elevation chance of -515 m (-1,000 m, 0 m), pipeline outside diameter of 36 inches (48”, 24”), flow rate of 435,000 bpd (810,000 bpd, 210,000 bpd), as well as crude densities and inlet crude viscosities reflective of the respective diluted and upgraded products, as outlined in Table 4.2. Transport emissions assume average seasonal temperatures between summer and winter. The GHG emissions for transportation are determined to be approximately

1.7, 1.4 and 0.7 g CO_2e/MJ gasoline for dilution, CSC partial-upgrading and full-upgrading scenarios, respectively.

Though the same density requirements are met by dilbits and CSC partial-SCOs the estimate of emissions differs due to the difference in viscosity and the energy content based allocation of emissions to products. In the case of the CSC partial-upgrading pathways, this energy based allocation of emissions to gasoline products is lower than that of dilution as reflective of more of the product slate from the refined dilbit being gasoline in comparison with CSC partial-upgrading. For further discussion regarding functional units refer to Section 4.3.2.

4.2.7 Refining

PRELIM estimates energy and GHG emissions as well as the volume of the refinery products based on a specific crude oil assay. Crude assays, that characterize crude oil properties such as API, MCR, and molecular contents, are selected from the inventory that most resemble the specific properties of crude for the full-SCO and dilution pathways. The CSC partial-upgrading pathways and a dilbit pathway, representative of the original Athabasca Bitumen from the pilot plant study, required creating this crude oil assay based on bulk properties established in the pilot plant studies. Extrapolation of bulk crude properties is required for characterization of properties for 9 crude oil fractions defined by specific boiling point ranges (ex. heavy vacuum gas oil, 454°C – 525°C). The mass and volume of the characterized fraction are directly adapted from boiling point curves of the CSC partial-SCOs. For properties such as MCR, it is assumed that 100% of the MCR would be found in the atmospheric residue (characterized by distillation temperatures above 400°C) and 99% would be found in the vacuum residue (525°C$^+$). Other properties, including API gravity, sulphur, hydrogen and the K factor, are assigned to the crude oil fraction based on the relative distribution for crude oils with similar bulk content properties. It is assumed that the crude content/properties of the partial-SCO and dilbit fraction are representative of a Suncor Synthetic Heavy (Sour) [Abella, 2012]. The nitrogen content of the fractions is representative of the Bow River North – Canadian conventional crude (Heavy and Sour) [Abella, 2012]. Using the relative mass fractions for the partial-SCOs and dilbit, the sum of the content of individual fractions are calculated to ensure the fractional contributions are reflective of the measured bulk properties. The complete crude oil assays used for representing the CSC partial-SCOs and Athabasca bitumen dilbit can be found in Appendix G.

The refinery configuration selected to process each crude is based on the crude properties such as API and sulphur content. A hydroskimming and medium conversion configuration is used for full-SCOs that exceed minimum pipeline specifications and a deep conversion processing for dilbits and partial-SCOs. Hydroskimming or medium refinery configurations are assumed to be used for full-SCO pathways due to limited hydroskimming refinery capacity in North America and because it is possible to process lighter crude oils with deeper conversion technologies. Though the refinery models is developed to account for refinery processing with specified product slates or different energy systems, the case study assumes GHG emissions are reflective of the average refinery emissions impact for the crude oils from the model's database which are reflective of the specific pathway. For example, coking full-upgrading refinery emissions estimates are the average emissions impact of the three full-SCO crude oil assays in PRELIM. Similarly, the product slate from these crude oil pathways are reflective of the average product slate, defined in terms of average end use emissions, from the crude oil database. Additionally, refinery process units operations for all pathways assume 'float case' process unit capacities, where process unit capacities reflect the boiling point characteristics of the crude oil being processed and the refinery is not set up to maximize production of certain products such as gasoline. Finally, these GHG emissions estimates are reflective of use of industrial natural gas boilers to supply head demands throughout the refinery.

PRELIM refinery emissions estimates are found to provide a range of emissions impacts due to analysis of multiple crude types that are reflective of the pathways, including three unique full-SCOs and five dilbits, as well as multiple refinery configurations including hydroskimming, medium and deep conversion [Abella, 2012]. The refinery estimates for deep conversion of the dilbits ranged from 73 to 105 kg CO_2e/bbl dilbit with an average pathway intensity of 81 g CO_2e/bbl dilbit assumed for this case study. The CSC partial-SCO refinery estimates assuming deep conversion are calculated with PRELIM to be 43 and 57 kg CO_2e/bbl partial-SCO for the CSC partial-SCO with and without the reincorporation of pitch, respectively. Due to the use of a single partial-SCO when evaluating the CSC partial-upgrading pathways, a range of GHG impacts for refining was assumed to be ± 25%. Estimates for the refinery emissions associated with full-SCOs refined with medium conversion or hydroskimming configuration are found to range from 23 to 69 kg CO_2e/bbl full-SCO with an average pathway intensity assumed to be representative of a medium conversion pathway for this case study (69 kg CO_2e/bbl full-SCO).

4.2.8 End Use

End use, or combustion emissions, are applied based on emissions factors of 74 grams of CO_2e per MJ of gasoline based on the GREET emissions impact estimates [Argonne National Laboratory, 2012]. When calculating for end use emissions in terms of multiple product, as is the case when calculating emissions using a bbl of bitumen as the functional unit, the end use emissions are assumed to be 74, 75, 67, 69, 97 and 75 grams of CO_2e per MJ for gasoline, diesel, jet fuel, fuel oil, coke fuel and bunker fuel products, respectively [Argonne National Laboratory, 2012]. The emissions associated with the production of other petrochemical, such as chemicals, waxes, and lubricants, are assumed to be negligible in comparison with the above mentioned fuel products which dominate the refinery output slate. The emissions calculations using the functional unit of per barrel of bitumen assumes that all refinery products are used/combusted and therefore have end use emissions impacts. Therefore, end use emissions calculation using a functional unit of bbl of bitumen use relative volume of bitumen to the volume of refinery feedstock as well as the relative volume of the various refinery products (refer to Section 4.3.2 for further discussion of functional units).

However, removed by-products from the upgrading stage in the form of pitch or coke are assumed to have no further use and are therefore not assigned downstream life cycle impacts. The potential use of these upgrader 'by-products', such as petroleum coke used in place of coal for electricity generation or as input material for the cement industry, often leads to diverging views with respect to emissions policies and allocation. Additionally, it should be noted that, unlike upgrader produced coke, coke produced as part of the refinery product slate is assessed end use emissions when calculating life cycle GHG emissions per bbl of bitumen. The application and emissions policy ramifications of these by-products will be discussed further in the policy section.

4.3 Comparative Life Cycle GHG Emissions Results

4.3.1 Case Study of GHG Emissions Calculated with the Integrated LCA Model

The life cycle GHG emissions estimates for the oil sands pathways with respect to the functional unit of a MJ of gasoline product can be seen in Figure 4.2. The life cycle estimates for oil sands pathway with respect to the functional unit of bbl of extracted bitumen can be seen in Figure 4.3.

For GHG emissions per MJ of gasoline product, the emissions estimates for the two CSC partial-upgrading pathways differ significantly based on whether or not the pitch is included in the CSC partial-SCOs (case study estimates of 95 g CO_2e and 102 g CO_2e / MJ gasoline). The CSC partial-upgrading with pitch is found to have emissions that are lower than the naphtha dilution pathway emissions range and the CSC partial-upgrading without pitch is found to have a similar emissions range to coking full-upgrading. This study found overlapping emissions ranges for all oil sands pathways. However, emissions ranges from the integrated LCA model are estimated based on a combination of operational parameters and therefore equal probability of results within the emission range is not expected. The case study emissions estimates found CSC partial-upgrading process with pitch had the lowest pathway GHG emissions followed by similar emissions estimates for naphtha dilution and hydrocracking full-upgrading and the highest emissions estimates for coking full-upgrading and CSC partial-upgrading process without pitch. The increased emissions for the CSC partial-upgrading process without pitch and coking full-upgrading are attributed in part to the removal of materials (pitch or coke) which is penalized with additional required bitumen extraction to produce the same volume of final product when calculating emissions using a MJ of gasoline as the functional unit.

For emissions per bbl of bitumen, coking full-upgrading is found to have the lowest pathway emissions because the removal of coke during upgrading, which is assigned no further emissions, caused less downstream processing and fewer end products from the single barrel of bitumen. Similarly, the effects of removal of by-products during CSC partial-upgrading without pitch caused lower emissions WTW GHG estimates (base case of 565 kg CO_2e /bbl bitumen) that are comparable to the calculated range of emissions for coking full-upgrading. The high emissions estimates in the case of dilution and CSC partial-upgrading with pitch (base case of 687 kg CO_2e /bbl bitumen) are reflective of the use of diluent and the associated emissions with a more crude oil being transported and refined into final products when calculating emissions using a MJ of gasoline as the functional unit.

Figure 4.2 - Case study comparison of WTW emissions of different oil sands pathways per mega joule of gasoline

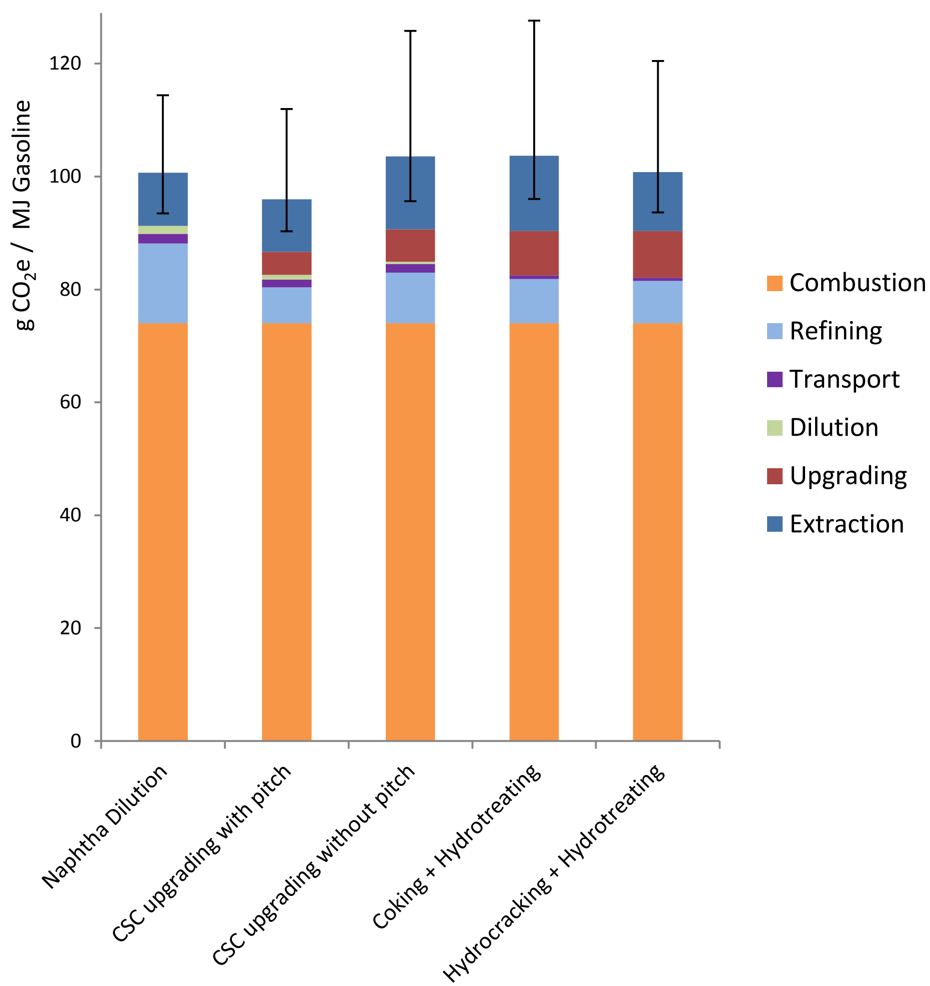


Figure 4.3 - Case study comparison of WTW emissions of different oil sands pathways per barrel of extracted bitumen

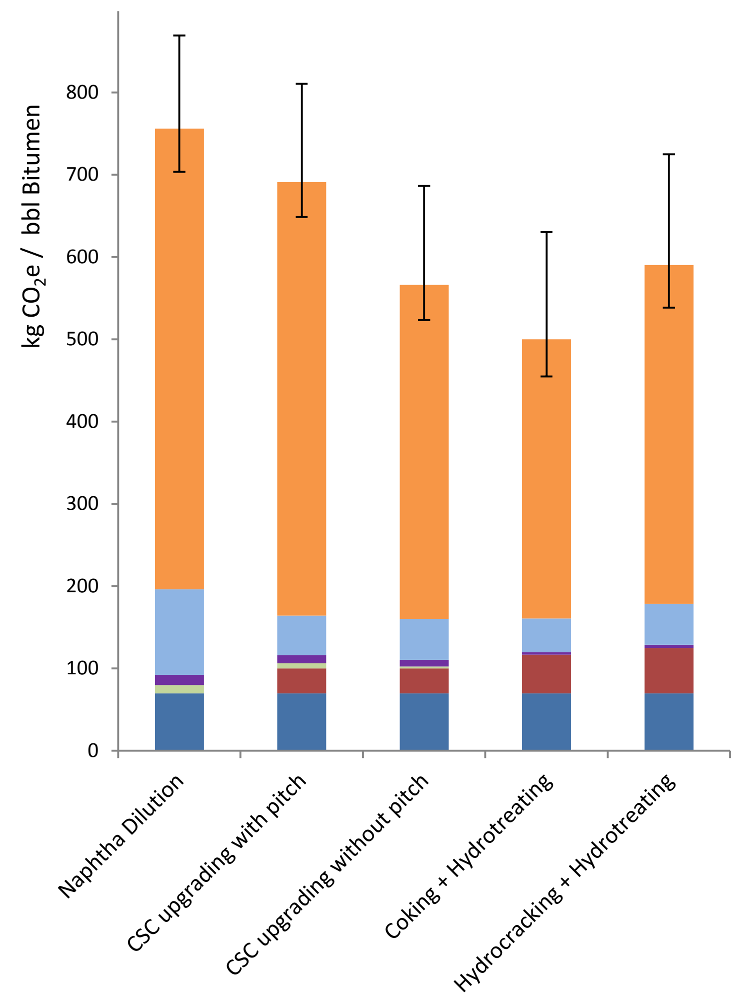
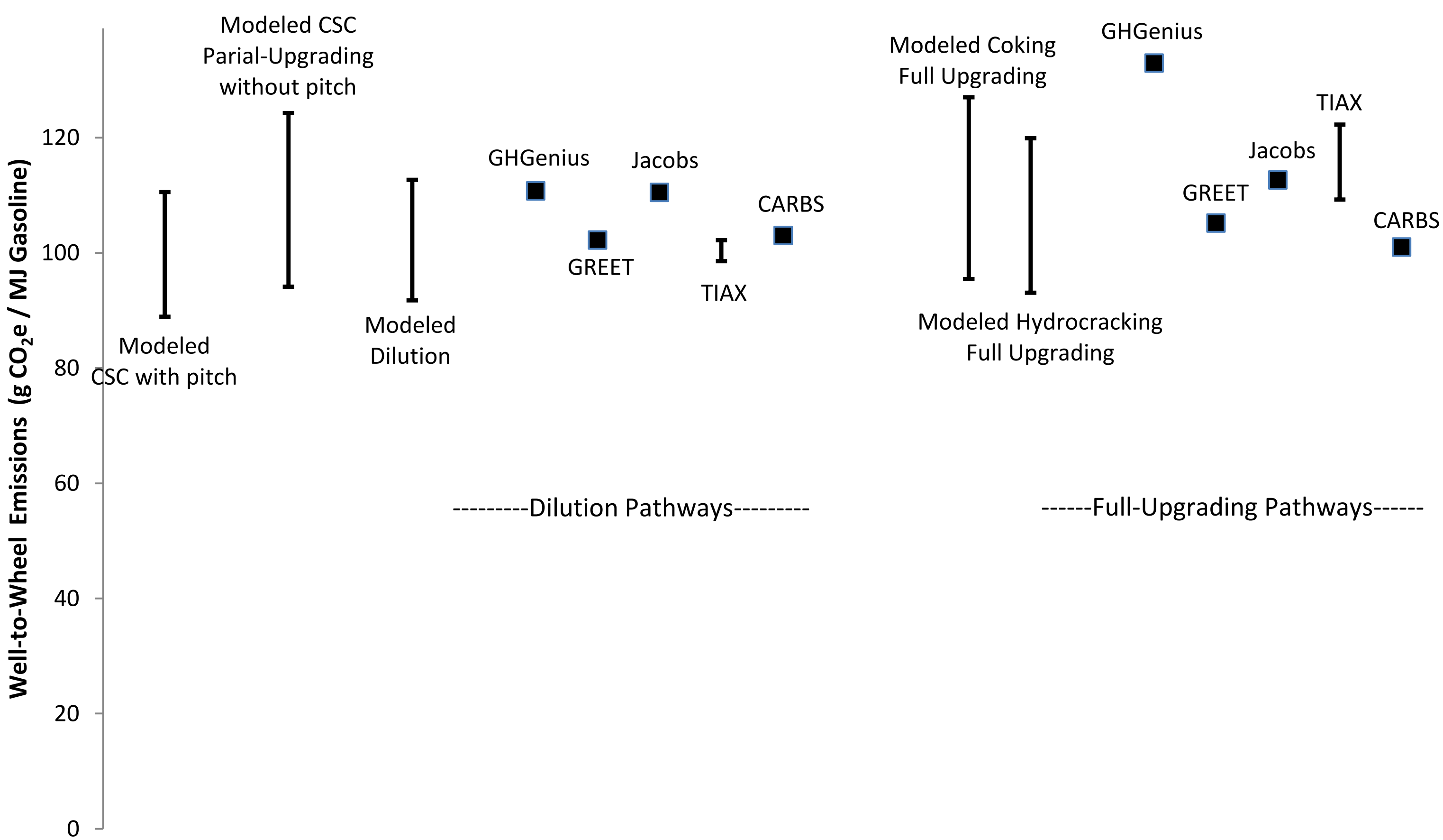


Figure 4.4 - Comparison of case study results with previous literature studies



4.3.2 Comparison of Calculated GHG Emissions with Literature

The majority of literature reporting emissions estimates for oil sands pathways are either developed based on a specific set of operational assumptions or are compiled in meta-analyses of prior studies [Bergerson, 2012]. Due to a lack of WTW emissions studies where emissions are assessed per barrel of bitumen, this literature comparison addresses emissions estimates using the functional unit of a MJ of gasoline. The literature studies with which pathway specific emissions are compared are based on estimates by GHGenius, GREET, Jacobs, TIAX and CARB [$(S\&T)^2$ Consultants Inc., 2012. Argonne National Laboratory, 2012. Jacobs, 2009. TIAX, 2009. California Air and Resources Board, 2011]. The emissions estimates from the case study presented in this chapter as well as the literature estimates are represented by squares for point estimates and a bar is used to represent emissions ranges. The results presented represent the respective study's findings for in-situ extraction, dilution or full-upgrading, pipeline transportation and refining. These study results are normalized for gasoline combustion emissions of 74 g CO_2e/MJ gasoline.

This figure demonstrates that the range of emissions for the pathways modeled in this study using the integrated LCA tool are generally representative of the literature estimates for WTW GHG emissions of oil sands pathways. The CSC partial-upgrading pathway which includes pitch is found to have low end emissions which are below the literature estimates for current dilution and full-upgrading pathways. The high end of the range of emissions for this pathway is comparable with literature estimates for dilution and some estimates for full upgrading. With the exception of GHGenius literature estimates for full-upgrading pathways which had the highest life cycle emissions, literature estimates for dilution and full-upgrading pathways are all within the range of potential life cycle emissions for CSC partial-upgrading pathway which does not include pitch.

4.4 Discussion of Life Cycle Emissions Case Study Results and Policy Implications

The case study GHG emissions calculations are discussed with respect to current and potential future emissions policies. This section addresses current emissions policies, LCFS and SGER, as well as potential economy wide emissions policies. The effect of these emissions policies on the case study emissions results is used in the cost-benefit economic assessment framework developed in the subsequent section.

The functional units selected for calculating emissions, and the respective allocation method, are intended to best represent the life cycle process for the respective policies. However, the oil sands pathways are further complicated through actual practices, such as batch transportation and refining of crudes, which may not be reflected in the presented calculations, as well as different operations electing to stockpiling or use of by-products. This simplified model for the evaluation of a single crude is assumed to be reasonable for representing the actual process because emissions allocation methods used for the respective functional unit based GHG calculations. Energy based allocation, as defined by the refinery process, is assumed to represent the relative impacts from specific downstream processing in terms of an end product and volume ratios are used in estimation of upstream processes in terms of the extracted bitumen. For example, upstream emissions per unit energy of a final product are assumed higher for extraction of coking full-upgrading pathways compared with dilution pathways because more bitumen would be required to be extracted to product the same volume of final product. However, end use emissions estimates per barrel of bitumen are significantly lower for the fully-upgraded pathways due to less final products being produced, and subsequently combusted, compared with dilution pathways that have considerably more final product. This is furthered through the assumption that the diluent is being refined into final products as opposed to simply being separated with the distillation process and re-transported for the use of diluent with separate processes and associated life cycles. In a similar manner, emissions calculations based on energy content can also affect results for relative transportation emissions despite similar transport properties (density), as seen in the transportation calculation for partial-upgrading and dilution pathways.

The California LCFS currently has emissions threshold for Well-to-Refinery (WTR) emissions of 15 g CO_2e/MJ of gasoline and WTW emissions of 95 g CO_2e/MJ of gasoline are established for crude oils sold into the California market in 2013 [State of California, 2006]. (Refer to Figure 4.2) Based on these case study results, the CSC partial-upgrading with pitch and dilbit pathways approached current LCFS threshold for WTW emissions. As discussed earlier, diluent is assumed to be refined into final products and the removed by-products from upgrading are not assessed emissions when calculating emissions in terms of a MJ of gasoline. Due to these assumptions, the CSC upgrading with pitch has considerably lower emissions than the CSC partial-upgrading without of pitch pathway. This form of GHG emissions calculation provides a disincentive to remove pitch or coke through assigning higher extraction emissions based on more required raw crude.

Accounting for the high and low emissions impacts established for CSC partial-upgrading in Chapter 3, the case study emissions impacts for the partial-upgrading process with pitch resulted in a WTW emissions range which could meet the current LCFS WTW threshold. However, this threshold is decreasing annually and therefore meeting future WTW emissions threshold will require further emissions reductions to the low impact emissions calculated for CSC partial-upgrading in Chapter 3.

The California LCFS also established a threshold for WTR emissions of 15 g CO_2e/MJ gasoline. Through calculating these pathway emissions from WTR, this emissions calculation doesn't account for differences in refinery processing different qualities of crudes. Due to this WTR threshold, the case study results from this evaluation suggest the dilution pathway is likely the only pathway which could have emissions under this WTR limit due to the additional emissions impacts of CSC partial-upgrading or full-upgrading, for those respective pathways. Therefore, the use of WTR calculations suggests that California LCFS incentivizes oil sands to elect to modify upstream emissions activities (prior to refining) without accounting for downstream emissions trade-offs.

The Alberta based SGER industrial emissions tax for high emitters applies a tax of $15 per tonne for all GHG emissions above an annual operational emissions threshold. The funcational unit used for representing the emissions calculations with respect to the SGER, as well as the economy wide carbon tax discussed later, is used to represents upstream and downstream emissions impacts as well as including end use emissions associated with the entire product slate. However, SGER is limited to operations in Alberta and does not account for out of province processes or end product markets. Additionally, the SGER is applied to high emitting facilities based on a reduction from baseline emissions (defined based on 2007 operations or the first year of commercial operation) and therefore it can be difficult to make a comparison of the cost of emissions for different facilities or operations. In the case that the bitumen is transported for refining out of province, only extraction and upgrading processes would be assessed under the provincial tax.

With respect to SGER, this case study comparison of pathway emissions from the CSC partial-upgrading shows the relative reduction in upgrading stage emissions compared with coking and hydrocracking full-upgrading estimates (addressing upgrading emissions calculations and not WTW emissions). Estimated case study emissions of 47 kg CO_2e and 57 kg CO_2e per barrel of extracted bitumen are determined for full-upgrading with coking and hydrocracking technologies respectively. In comparison with the case study estimates for CSC partial-upgrading, this GHG emissions comparison found a 34% and 47% reduction in upgrading stage emissions per barrel of bitumen compared with coking and hydrocracking full-upgrading (as seen with the upgrading emissions bars in Figures 4.2 and 4.3). However, current SGER are applied to all large scale emissions facilities based on an emissions threshold which is specific to the facility and therefore limits simple comparisons between a small-scale partial-upgrading facility and full-upgrading facility. Assuming 100,000 bpd CSC partial-upgrading and hydrocracking full-upgrading facilities that are both taxed on 12% of total emissions at \$15/tonne CO_2e, the case study emissions results translate to approximately \$2.0 M and \$3.7 M in taxes annually.

The significant difference between the case study emissions impacts from coking and hydrocracking full-upgrading pathways and CSC partial-upgrading is attributed to the additional crude processing, requiring additional process units, and the source of hydrogen for the full-upgrading processes. As discussed in Chapter 2, CSC partial-upgrading produces hydrogen from steam which is in contrast to the typical industry practice of producing hydrogen from steam methane reforming (gasification of hydrocarbons, such as produced coke or pitch, could also be used but this was not assumed for this study). Based on equivalent processing capacities, the model estimates hydrocracking full-upgrading consumes more hydrogen and has approximately 17% higher associated upgrading stage emissions per bbl of bitumen and 15% higher WTW emissions per bbl of bitumen compared with coking full-upgrading. However, the production of a significant amount of coke by-product during coking full-upgrading results in approximately 15% less upgraded product from coking full-upgrading in comparison with hydrocracking upgrading pathway which affects both emissions allocation to specific products, such as gasoline, and the revenues from sale of the full-SCO products, as seen later in the cost-benefit analysis in Section 4.5.1.

In the case of refining out of province, the dilution option results in the lowest emissions impact within the province. In comparison with CSC partial-upgrading, the dilution pathway could avoid over 1,000 kilotonnes of GHG emissions per year associated with the operation of a 100,000 bbl/day partial-upgrader facility. However, CSC partial-upgrading stage emissions were calculated to be 16 and 26 kg CO_2e/bbl bitumen less than coking and hydrocracking full-upgrading which could result in a total decrease in annual GHG emissions of approximately 600 and 1,000 kilotonnes for a 100,000 barrel per day operation.

Considering the high and low impact estimates for process requirements and GHG emissions calculation in Chapter 3, the high impact emissions estimates for the CSC partial-upgrading stage emissions exceeds the case study estimates for coking full-upgrading. However, the high impact scenario is developed to be reflective of very uncertain estimates for industrial scale process requirements such as two and a half times the steam requirements for the CSC upgrader process units compared with pilot plant requirements. Similar calculation for case study estimates, such as double the steam requirements for CSC pilot plant upgrading, also suggest that the industrial scale steam process requirements could be lower than case study emissions results. Additionally, the possibility of process optimization, improved catalyst performance due to on-stream catalyst preparation or recycling catalyst could be used to further reduce the impacts of this pathway. For these reasons the estimated range is very broad as reflective of the uncertainty in estimating industrial processing impacts of CSC partial-upgrading and use of process units, which have not yet been developed at an industrial scale. Further environmental evaluation of partial-upgrading processes once industrially implemented could greatly improve these operational emissions intensity estimates.

The SGER has limited regional jurisdiction, however, an economy wide carbon tax could be used to account for all processing and products from extraction of the bitumen to the final product slate. For the purposes of assessing upgrading and dilution pathways, it is assumed that the functional unit of a bbl of bitumen can be used for assessing the impact of the SGER as well as a form of economy wide carbon tax.

When comparing the pathways in terms of a potential economy wide carbon tax, the coking full-upgrading pathway, followed by CSC partial-upgrading without pitch, were found to have the lowest WTW GHG emissions impacts and the dilbit pathway, followed by CSC partial-upgrading with pitch, was found to have the highest emissions. Due to the assumptions that by-products from upgrading are not assessed end use emissions, this form of policy incentivizes the removal of the heaviest oil fractions, that also have high associated processing requirements, through decreasing the relative amount of crude oil which is transported, refined and comprises the product slate. Additionally, the assumption that the diluent, along with the crude oil, is refined into the refinery product slate effectively disincentives the use of diluent due to the increased volume of crude that required downstream transportation, refining and end use. The specific influence of this type of potential economy wide carbon tax is explored further with the cost-benefit analysis of oil sands investment pathways, presented in the following section.

The emissions calculation methods which are used to represent the current and potential future emissions policies in this study were found to incentivise different pathway options (with LCFS being more attuned to dilbit pathways and an economy wide carbon tax being more attuned to upgrading pathways which remove the heaviest crude oil fractions). Proponents of calculating emissions per barrel of bitumen often suggest that if these pitch and coke are produced as a by-product and if these by-products are not combusted or used in another process then they do not cause any further airborn emissions and should therefore not be included in the emissions calculations. Opponents of this form of policy often suggest that once the oil is extracted from the ground then all life cycle emissions associated with the product slate need to be assessed for their potential use. Consideration for various functional units and associated emissions allocations methods are required to better inform current policies and aid in future policy development.

The ideal operation of the CSC partial-upgrading facility, with respect to integration or stockpiling of pitch, depends upon the specific policy assessments. The adaptability of CSC partial-upgrading to operate with or without the pitch in the partial-SCO allows for an upgrader to operate based on specific emissions policies or price of the CSC partial-SCO and diluent. For example, in tailoring the operation to a LCFS policy which measures emissions in terms of final product, the inclusion of pitch can be used to have lower reported emissions per MJ gasoline. However, in the case of a carbon tax then the removal of pitch during upgrading would lead to lower emissions reported per bbl bitumen. The adaptability of this pathway is similar to how full-upgraders can use their higher quality product for the dilution of more bitumen, commonly known as Synbits. However, the partial-upgrading pathway has the benefit of lower upstream emissions for naphtha diluent comparison with the upstream emissions associated with the production of fully-upgraded oil used for dilution in the case of a Synbit pathway [TIAX, 2009].

4.5 Method for Cost-Benefit Comparative Case Study

This case study uses cost-benefit analysis framework to inform investment decisions regarding either CSC partial-upgrading, coking full-upgrading and naphtha dilution pathways for an in-situ oil sands project. Assessing the economic value of oil sands investments requires consideration for factors such as capital and operational costs, taxes, royalties and climate policies. Projections for these economic factors, along with projected future market prices for diluted bitumen, partial-SCO, full-SCO, naphtha, utilities and process requirements, can ultimately lead to different conclusions about preferred investment options. For this reason, this section uses a cost-benefit framework to assess different oil sands pathways based on projected net present value (NPV). This framework is developed based on a similar cost-benefit framework by Choquette-Levi et al. which is used to address the question of 'Should Alberta Upgrade Oil Sands Bitumen?' [Choquette-Levy, 2013]. Adapting this type of cost-benefit framework allowed for a direct comparison with established dilution and full-upgrading pathways while allowing for the CSC partial-upgrading pathways to be modeled as well as specifying the emissions policies and pathway emissions results from this study, future market consideration and calculations for revenues, expenses, taxes and royalties. For the purpose of this evaluation, it is assume the GHG emissions and economic impacts are reflective of the case study analysis of the CSC partial-upgrading pathways and the case study for coking full-upgrading and dilution pathways are based on the emissions estimates from previously in this chapter. SAGD extraction is assumed for all pathways.

This assessment does not explicitly include the risk of different investment options. For example, uncertainties with respect to the price of future crude products and operational costs are not explicitly addressed and quantified as part of this analysis. For the purpose of this evaluation the risk associated with these investments is captured through varied discount rates where, for example, a risk averse investor would select a high discount rate to ensure a high rate of return on their investment.

4.5.1 Partial Cost-Benefit Framework Description

The cost-benefit analysis used for comparing oil sands investments considers revenues for selling the diluted or upgraded products to refineries at the market price for the respective products which are related to the crude oil quality. For this case study it is assumed that partial-SCOs will be sold at the same price as dilbit forecasted prices with fully-upgraded SCO selling at a premium. The case study assumed that costs associated with SAGD extraction include initial capital costs and sustaining capital, and O&M costs. Costs associated with dilution pathways include cost of diluent and capital for a dilution facility. The upgrading facilities require consideration for initial capital costs and sustaining capital costs, and operations and maintenance costs as well as the cost of diluent in the case of CSC partial-upgrading. Additional consideration for income taxes and royalty payments to the provincial and federal government as well as carbon taxes under different CO_2e price policies.

Annual productions of dilbit, CSC partial-SCOs and full-SCOs as well as respective diluent requirements are based on the GHG emissions case study developed previously in this chapter. Capital costs and O&M economic estimates for the CSC partial-upgrader pathways are based on the economic analysis completed as part of industrial scale estimates in Chapter 2. Capital and annual expenses for the SAGD extraction, coking full-upgrading pathway and the dilution pathway are adapted from Choquette-Levy et al., with coking full-upgrading costs based on a 2011 CERI report and dilution estimates based on a report by the Edmonton Economic Development Corporation [CERI, 2011. Choquette-Levy, 2013]. To account for the difference in facility capacities between the studies, the costs used in this study for a 100,000 bpd facility are calculated by multiplying the costs from the previous studies/literature by the relative capacity difference with the cost escalation exponent of 0.7 [Pereira-Almao, 2012]. For example, Choquette-Levy calculated the capital cost for a 150,000 bpd coking full-upgrader at a $7.9 B, which is multiplied by the difference in total capacity (100,000 bpd/ 150,000 bpd) to the cost escalation exponent of 0.7 to results in the $5.9 B capital cost for a 100,000 bpd coking full-upgrading facility assumed in this study. The operations and maintenance costs estimates for CSC partial-upgrading, calculated in the previous chapter, are assumed to be divided amongst additional annual capital investments and O&M costs based on the ratio of additional capital and O&M for coking full-upgrading. These costs are divided for the purposes of calculating taxes, as discussed later in this chapter. The following table outlines the economic estimates that are used as part of this case study comparison investment options.

Table 4.3 Case study assumptions for pathway investment comparison

	CSC Partial-Upgrading with pitch	CSC Partial-Upgrading without pitch	Coking Full-Upgrading	Naphtha Dilution
Crude oil produced	111,000 bpd	98,000 bpd	85,000 bpd	143,000 bpd
Diluent required	22,000 bpd	13,000 bpd	0 bpd	43,000 bpd
Extraction Capital	$ 5.3 B	$ 5.3 B	$ 5.3 B	$ 5.3 B
Annual extraction capital	$ 250 M	$ 250 M	$ 250 M	$ 250 M
Extraction O&M	$ 370 M	$ 370 M	$ 370 M	$ 370 M
Upgrading/Dilution Capital	$ 2.0 B	$ 2.0 B	$ 5.9 B	$ 3.8 M
Annual Up/Dil capital	$ 12 M	$ 12 M	$ 47 M	$ 0*
Up/Dil O&M	$ 150 M	$ 150 M	$ 230 M	$ 0.20 M

*Though sustaining capital would be required for repairs in the case of dilution tanks, it is assumed that these annual costs would be negligible.

Projections for crude price estimates can significantly affect the economic evaluation of these pathways. For this case study the crude prices are adapted from Choquette-Levy et al. which forecasted naphtha prices based on linear best-fit relationship from naphtha prices over the past 16 years and use of industry elicitation for projected prices of diluted bitumen and full-SCO [Choquette-Levy, 2013]. This case study assumes that diluent prices would range from $82/bbl at year one of production to $210/bbl, diluted bitumen would range from $75/bbl at year one to $144/bbl and fully-upgraded oil/full-SCO would range and $81/bbl at year one to $162/bbl. It is assumed that partial-SCO is sold at the same price as diluted bitumen though further analysis of the economic value of the partial-SCO could be used to better inform these economic scenarios. Additionally, the effects of these forecasted crude prices are evaluated in part through a sensitivity analysis of the CSC partial-upgrading evaluation. However, further development of this economic framework could better capture the risk associated with these pathway decisions in circumstances, such as constrained pipeline capacity for diluent with increasing demand in Alberta.

Royalty and tax expenses applied to these projects are assessed in accordance with current royalty and tax structures [Government of Alberta, 2007]. The Alberta royalty structure is a two tier structure with reduced royalty taxes for operations before hitting a payout rate. This payout rate is defined as a 5.5% rate of return on cumulative capital cost allowances and operational expenses. Before this payout rate is reached, royalties are charged against gross revenue with royalty rates of 1% - 9%, based on the crude prices of West Texas Intermediate (WTI) where crude prices up to $55/bbl are assessed a 1% royalty rate until a ceiling of 9% is reached for crude prices of $120/bbl or greater. After the payout rate is reached, royalties are charged against net revenues with royalty rates of 25% - 40%, depending on the price of the WTI. This model assumes that the current Alberta royalty structure will remain unchanged for the duration of the projects.

Income taxes are applied after royalty costs and carbon taxes with consideration for depreciation and capital cost allowances. This economic analysis assumes all capital assets will fall into class 41.1 (Oil Sands) for Canadian income tax purposes. Thereby, 25% capital cost rate per year remains and yearly additions will be subject to the half year rule (class 12 assets for capital cost allowance purposes). Current corporate income tax rate in the province of Alberta is 29% and this case study assumes that it will remain unchanged for the project duration and the corporation will not qualify for any grants or credits such as scientific research and experimental development credits (SR&ED). The calculation assumes that all funds required to pay for capital assets will be raised through equity and therefore, no debt or interest expenses are assumed. Additionally, it is assumed that no capital assets would be sold during the project lifetime.

Understanding the influence of emissions policies on these long-term investment decisions is one of the principle goals of this economic assessment. For the purpose of this evaluation, a hypothetical tax is assumed to be applicable to all GHG emissions across all sectors and would therefore include both direct emissions from the extraction and processing as well as indirect emissions such as electricity consumption. For the purpose of this study, it is assumed that removed pitch/coke during upgrading is not used further and any required diluent is not recycled. Therefore, end use emissions associated with these pathways are reflective of the total volume of the refinery product slate.

This study assumes these respective pathways are assessed emissions taxes based on the extraction and upgrading or diluent emissions estimates as established previously in this chapter. For example, this study assumes CSC partial-upgrading pathway with pitch would be assessed an economy wide emissions tax on 69, 31 and 1 kg CO_2e per barrel of crude for extraction, upgrading and required diluent.

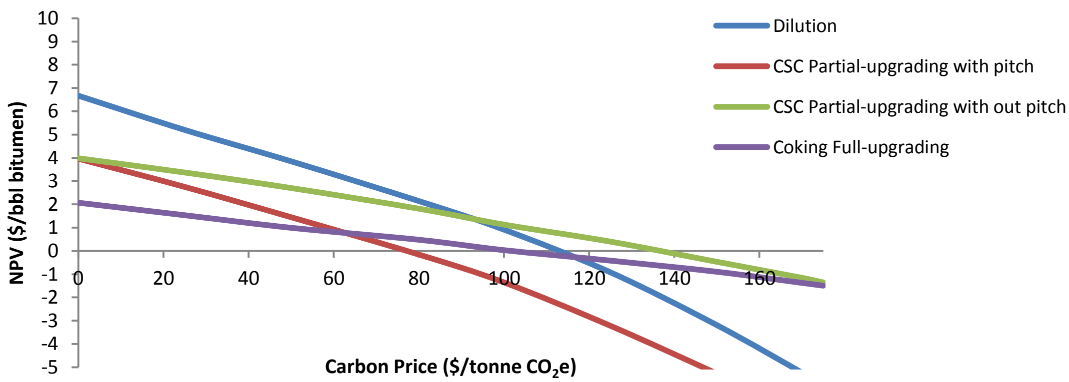
This form of economy wide carbon policy would likely lead to refineries, that purchase the crude and therefore take on the downstream crude emissions, penalizing a crude which resulted in higher emissions or pay a premium for crudes with lower emissions. This case study assumes that increased downstream emissions costs above a certain emissions intensity limit would be passed along to the producer (for this study, the extraction and upgrading/dilution oil sands operator). This study assumes that the emissions intensity limit is defined by the comparative pathway with the lowest downstream emissions, which is determined to be the coking full-upgrading pathways with 3, 43, and 340 kg CO_2e per barrel of crude for transportation, refining and the end use product slate. Therefore, pathways with downstream emissions that exceeded that of the coking-full upgrading pathway are assumed to incur the GHG emissions costs for downstream emissions above this limit of 386 kg CO_2e per barrel of crude. For example, the CSC partial-upgrading without pitch would be penalized by the refineries for the additional 5, 7 and 66 kg CO_2e per barrel of crude for emissions exceeding downstream emissions limit set for transportation, refining and end use based on the coking full-upgrading pathway.

The economic comparison uses the projects NPV as an indicator of the potential of these investments under an economy wide carbon tax. This economic comparison is performed using different discount rates as reflective of different expected rate of return on oil sands investments. Sensitivity analysis with respect to cost factors for the CSC partial-upgrading pathways is also conducted to better understand the influence of factors such as capital cost on the investment value. Key performance factors evaluated as part of this sensitivity analysis include capital and O&M costs and crude market prices.

4.6 Cost-Benefit Case Study Results

The cost-benefit framework developed for comparison of oil sands pathways is used to compare the net present value of the 30 year oil sands investment pathways, for SAGD extraction with dilution, CSC partial-upgrading with pitch, CSC partial-upgrading without pitch, or coking full-upgrading. The case study assumption for this economic assessment assumed a 10% discount rate. The results from the case study economic comparison are presented in Figure 4.5 with respect to an economy wide carbon tax.

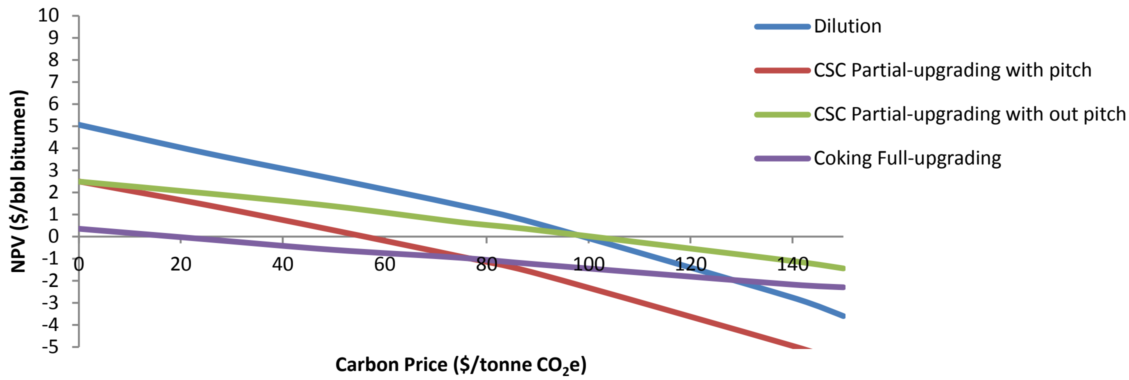
Figure 4.5 NPV of different oil sands pathways as a function of economy wide carbon price (assuming a discount rate of 10%)



The value of the oil sands investment pathways, assuming a 10% discount rate, for the extraction and dilution/upgrading of 100,000 bpd of bitumen without a carbon price are $6.67, $3.96, $3.98, and $2.07 per barrel of bitumen for dilution, CSC partial-upgrading with pitch, CSC partial-upgrading without pitch, and coking full-upgrading, respectively (seen with the investment values at $0/tonne CO_2e, y-intercepts, in Figure 4.5). Assuming a discount rate of 10%, the CSC partial-upgrading without pitch is the preferred pathway at a GHG prices higher than $90/tonne CO_2e (below this dilution is preferred).

When the investment decision considers a higher discount rate, therefore expecting a higher rate of return, we can see a decreased investment NPV and that the breakeven point for a change in investment choices shift to a higher emissions intensity pathways occurs at a higher carbon tax in comparison with the case study analysis. The following figure displays the above characterized investment choices under a discount rate of 12%.

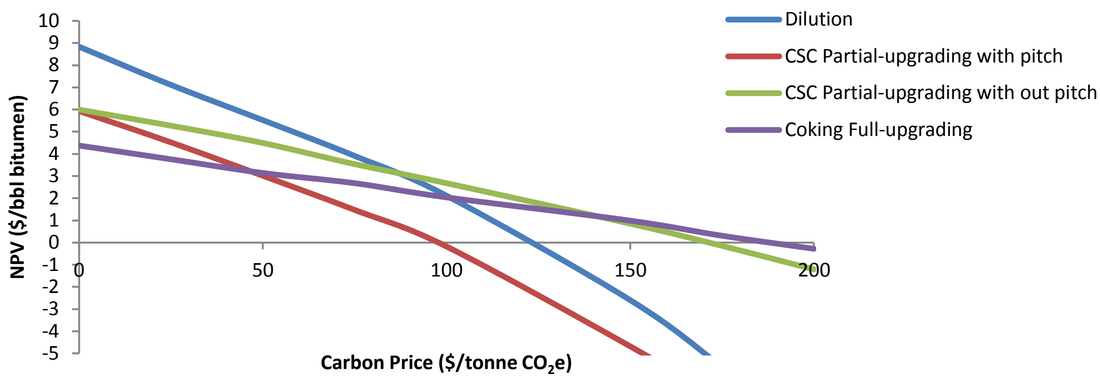
Figure 4.5 NPV of different oil sands pathways as a function of economy wide carbon price (assuming a discount rate of 12%)



When the applied discount rate is increased to 12%, the value of the 30 year oil sands investment pathways for the extraction and dilution/upgrading of 100,000 bpd of bitumen without a carbon price are $5.06, $2.50, $2.49, and $0.36 per barrel of bitumen for dilution, CSC partial-upgrading with pitch, CSC partial-upgrading without pitch, and coking full-upgrading, respectively. It is found that the carbon price at which CSC partial-upgrading would yield a higher investment value than dilution would occur as the NPV of these pathways approached a project break-even point (NPV of $0).

On the contrary, when a lower discount rate is applied to this economic analysis, as representative of lower associated investment risk, we can see increased investment NPV and that the breakeven point for a change in investment choices shift to a lower emissions intensity pathways occurs at a higher carbon tax in comparison with the case study analysis. The following figure displays the above characterized investment choices under a discount rate of 8%.

Figure 4.7 NPV of different oil sands pathways as a function of economy wide carbon price (assuming a discount rate of 8%)



When the discount rate is decreased to 8%, the value of the 30 year oil sands investment pathways for the extraction and dilution/upgrading of 100,000 bpd of bitumen without a carbon price are \$8.83, \$5.93, \$5.99, and \$4.38 per barrel of bitumen for dilution, CSC partial-upgrading with pitch, CSC partial-upgrading without pitch, and coking full-upgrading, respectively. This economic assessment resulted in a higher NPV for CSC partial-upgrading without pitch compared with dilution at a GHG price of \$80/tonne CO_2e. However, the value of the coking full-upgrading pathway is found to have a higher investment value than CSC partial-upgrading at GHG prices above \$145/tonne CO_2e.

Further characterization of the factors influencing this investment decision is performed as a sensitivity analysis of the CSC partial-upgrading pathways investment values. The relative effects on the case study NPV are analyzed to determine the effects of some of the economic model assumptions. The evaluation of the effects of crude prices on the investment value is assessed with respect to the projected prices inflation over the project lifetime (with crude prices at year one remaining unchanged). Therefore, a 50% reduction would reduce the projected future crude prices from the case study prices of \$144/bbl at year 30 to \$109/bbl at year 30 (\$34/bbl increase from the \$75/bbl year one crude price instead of an increase of \$69/bbl over the project lifetime with the case study assumption). Finally, the relative change with respect to the capital and O&M costs are assessed for the industrial scale estimates established in Chapter 3. Factors with steeper slopes are generally more influential. Sensitivity analysis of these economic results for the CSC partial-upgrading process with pitch and without pitch can be seen in Figures 4.8 and 4.9, respectively.

Figure 4.8. Sensitivity analysis for NPV of CSC partial-upgrading with pitch (assuming a discount rate of 10%)

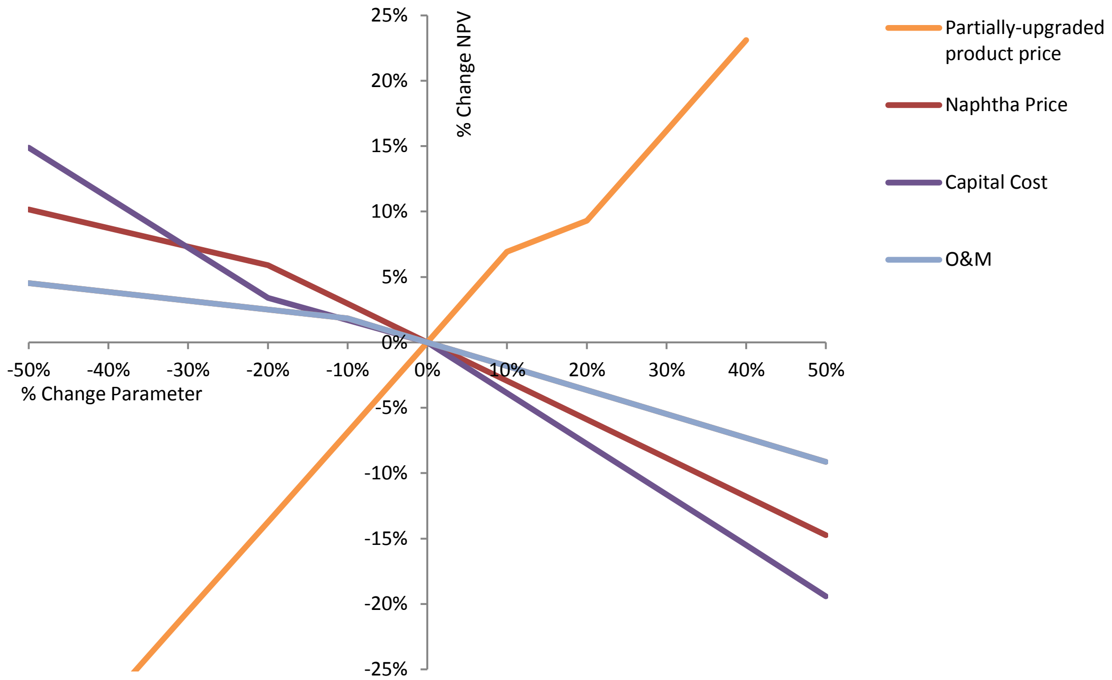
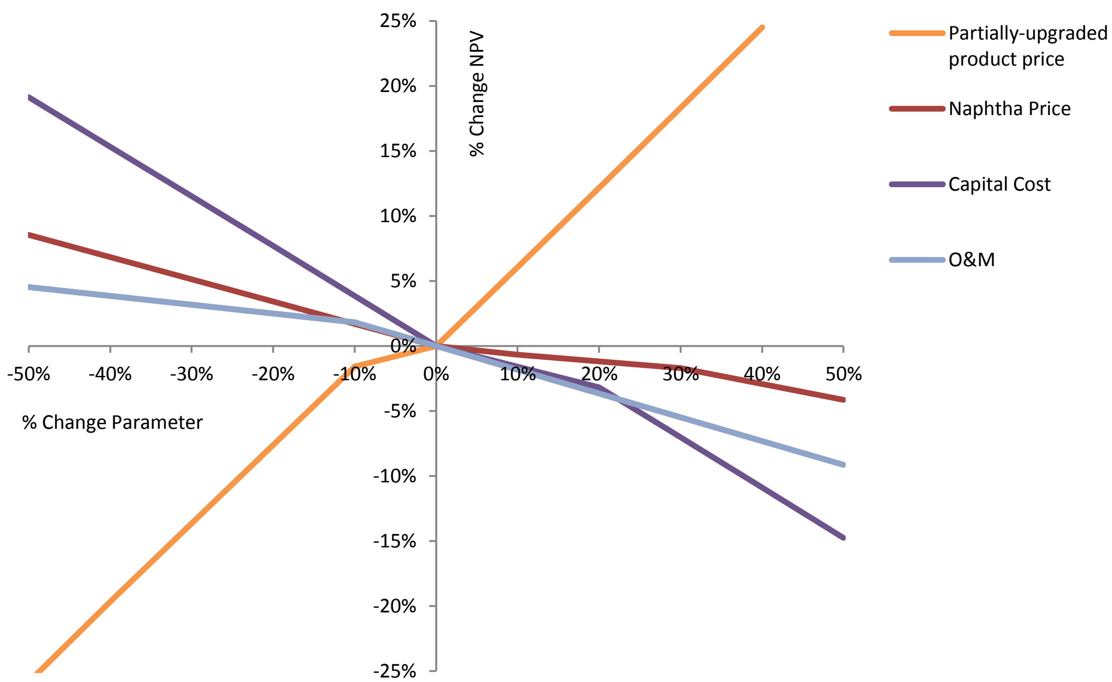


Figure 4.9. Sensitivity analysis for NPV of CSC partial-upgrading without pitch (assuming a discount rate of 10%)



This sensitivity analysis found that increasing the price of the partial-SCO is shown to have the largest incremental influence on the pathways NPV while the largest comparable negative correlation is with capital costs. This sensitivity analysis shows that both pathway's NPV are approximately half as sensitive to changes in the O&M costs as capital costs. The price of naphtha has a greater effect on the projects NPV for CSC partial-upgrading with pitch in comparison with when pitch is removed.

4.7 Discussion of Cost-Benefit Case Study of Results

The effects of an economy wide carbon tax on the investment value of the respective case study pathways indicate that different applied discount rates can lead to a preference for dilution, CSC partial-upgrading without pitch and coking full-upgrading.

The case study economic analysis, suggested that the assumed capital and operational costs along with the forecasted crude oil prices and diluent costs resulted in the dilution pathway yielding the highest return on an oil sands investment in accordance with current provincial royalty and income taxes and no emissions taxes. Without carbon pricing, the three different applied discount rates all resulted in the dilution pathway with the highest NPV, followed by the two CSC partial-upgrading pathways and then the coking full-upgrading. Based on the case study assumption and no applied carbon tax, this cost-benefit analysis suggested that the dilution, CSC partial upgrading with pitch, CSC partial upgrading without pitch and coking full-upgrading pathway had a payback period of 4, 6, 6 and 8 years.

When the applied discount rate is increased from the case study assumption, as shown with the applied discount rate of to 12%, it is found that the dilution pathway is likely to remain the preferred investment option regardless of an applied carbon tax. When higher discount rates are applied, the NPV of all pathways suggest the projects are no longer profitable before a carbon emissions taxes is reached which causes the dilution pathway (higher emitting) to have the same NPV as the CSC partial-upgrading pathway (lower emitting).

When the applied discount rate is decreased from the case study assumption, as shown with the 8% discount rate, it is shown that the preferred investment could be either dilution, CSC partial-upgrading without pitch or coking full-upgrading depending on the future carbon prices. When lower discount rates are applied, the dilution pathway is preferred until a sufficient carbon price is applied, at which point CSC partial-upgrading without pitch yields the highest NPV, due to the highest pathway emissions for dilution this economy wide carbon pricing structure. The results suggest that further increasing the economy wide carbon tax can result in the coking full-upgrading pathway being the preferred investment option due to the lowest pathway emissions. Therefore, the effect of this economy-wide emissions tax is shown to have interesting implication on the investment value of these oil sands pathways based on stakeholder desired rate of return or projected market prices and carbon taxes.

It can be seen that the investment value of both CSC partial-upgrading with and without the inclusion of pitch are most significantly affected by the price of the product where price increases above the assumed model projections are found to increase the project's net present value (the relative change in price of partial-SCO has approximately half that relative change on NPV). In the case of CSC partial-upgrading with pitch, the added diluent requirements result in the variability of diluent price becoming a significant factor in influencing the NPV in comparison with the CSC partial-upgrading without pitch.

Comparable influences of Capital and O&M costs on the project value are found in the case of both sensitivity analyses. The capital cost influences are found to be approximately twice as influential as O&M costs at an assumed 10% discount rate.

Nonlinearity in the sensitivity analysis and carbon pricing estimates can be attributed to interdependent effects of the economic factors on project expenses such as carbon and income taxes, royalty structures or capital cost allowance. For example, when crude prices are varied this affects royalties and income taxes paid. When capital costs or O&M costs are escalated they affect the royalty rate, capital cost allowance and income taxes paid. Carbon prices affect the calculation of royalties and income taxes where high escalation of carbon prices result in directly offsetting the income taxes paid for the project because income taxes are only paid once operations are profitable. Due to the nature of these energy system investment decisions we observe a complex and interdependence between key performance factors. Further development of this economic characterization could be used to further understand the complexity of these economic interdependencies.

4.8 Conclusions

This chapter shows that the CSC partial-upgrading has the potential for comparable emissions to the lowest pathway emissions estimates for both forms of emissions calculations presented in this chapter. The operational decision to include or not include the SDA produced pitch material into the CSC partial-SCO would allow for the plant operation to be tailored to specific policies. In the case of LCFS based policies, the inclusion of pitch material would lead to fewer emissions while overall emissions per barrel of bitumen are lower for CSC upgrading with the removal of pitch.

The cost-benefit assessment with the consideration of the cost of emissions is essential for informing these investment options and for assessing current and future emissions policies. The case study demonstrated how CSC partial-upgrading could be the preferred pathway option under certain carbon tax legislation. However, the expected rate of return, as reflective of the applied discount rate, was shown to significantly affect this decision; with higher applied discount rates to prefer dilution pathways and avoid the significant capital costs associated with an upgrading facility. This case study evaluation at lower expected rate of returns yielded preference for CSC partial-upgrading under certain carbon pricing schemes with and even coking full-upgrading at higher carbon rates. These case study findings suggest a CSC partial-upgrading scenario to have a higher NPV than dilution at lower CO_2e prices, under a lower discount rate. Further development of the economic framework to assess these options under varied carbon policies and projects market prices could better inform these investment decisions.

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5.0 Conclusions

This thesis illustrates the potential advantages and trade-offs of CSC partial-upgrading as an energy system investments for oil sands development. This thesis used pilot plant evaluation, projection of industrial scale implementation and modeling as part of an integrated LCA model for calculating GHG emissions and for the development of cost-benefit framework for comparing oil sands investments for the early stage evaluation of this CSC partial-upgrading in comparison with current industrial pathways for dilution and full-upgrading. Chapter five builds upon findings from earlier chapters to discuss insights from the analysis that is used to inform stakeholders, policy makers and researchers of the potential of this type of energy system investment. The chapter is broken down into: 1) review and major findings from the research; 2) research contributions; 3) consideration for future work; 4) take home messages for stakeholders and policy makers; 5) outlook for CSC partial-upgrading. The review section addresses the major findings from each chapter of the thesis.

5.1 Review and Major Findings from the Research

The development of the framework for early stage assessment of an energy system option in comparison with current industrial processes was fundamental in informing GHG emissions and economic comparisons. The methodological framework used in this emerging pathway evaluation included a technology evaluation of the process at the pilot plant scale, projections of the industrial scale process requirements through simulation software and industrial estimates, life cycle emissions estimates through a WTW emissions estimate model and cost-benefit economic comparisons. By accounting for life cycle emissions this methodological framework allows for these energy system options to be characterized with consideration of current and potential emissions policies to better inform investment decisions. This framework also allows for early stage identification of potential process efficiency improvement opportunities and optimizations in the further development of the emerging pathway.

Chapter 2 specifically addresses the evaluation of the CSC partial-upgrading at a pilot plant scale. Through evaluating the catalyst preparation process unit and CSC upgrading process unit for the various conditions the pilot plant evaluation determined: 1) representative catalyst preparation and CSC upgrading conditions; 2) characterization of the partial-SCO and gases produced. The catalyst preparation and CSC upgrading process units were evaluated to determine process requirements, such as the required catalyst and steam concentration, to inform the estimation of the GHG emissions and economic impacts of the industrial scaling for this type of upgrader. The evaluation of the CSC upgrading processes showed DAO and VGO conversion levels of 53% at 350^{o}C and 64% at 553^{o}C, respectively, while meeting stability requirements defined by P-value or micro carbon residue testing. The steam and catalyst requirements for the representative upgrading conditions required for VGO conversion are 5 weight percent steam and 200 and 400 ppm nickel and potassium catalyst. The steam and catalyst requirements for the representative upgrading conditions required for DAO conversion are 4 weight percent steam and 350 and 575 ppm nickel and potassium catalyst. Characterization of the partial-SCOs and produced gases are used to inform the relative downstream implications of CSC partial-upgrading. Characteristics such as density and viscosity are essential for calculating required dilution to reach pipeline specification and transportation emissions as well as thorough characterization of the crude for use in the PRELIM model for estimating refinery processes and impacts. The upgraded product from CSC partial-upgrading was found to have an API density of 12.5^{o} and 15.8^{o} for the upgraded product with pitch and without pitch, respectively.

Chapter 3 addressed the economic and environmental impacts of CSC partial-upgrading employed at industrial scale level. Engineering modeling software, Aspen HYSYS®, and industrial estimates from literature are used to determine the process requirements for the operation of the CSC partial-upgrader at 100,000 bpd. Through use of emissions impact estimates, the GHG emissions impacts are established based on process unit requirement estimates. Industrial economic correlations from literature and industry experts are used for the projection of capital, operations and maintenance costs for this partial-upgrader. This evaluation found the projected 100,000 bpd upgrader to have base case emissions impacts of 3.1 kilotonnes of CO_2e per day with high and low impact estimates of 5.0 and 2.2 kilotonnes per day (31, 50 and 22 kg CO_2e/bbl bitumen). The distillation process, SDA and CSC Upgrading are found to contribute 46, 20 and 26% of total GHG emissions for the CSC partial-upgrading plant. Potential reduction in steam requirements for the CSC upgrader process units could be as significant as 5% of total plant GHG emissions, from the base case results, if negligible loss of process steam required for CSC upgrading reaction (pilot plant requirements are directly scalable for industrial application).

Therefore, development efforts to optimize steam use in the CSC upgrading process units should be used in further development of CSC partial-upgrading. The economic evaluation of the CSC partial-upgrading process results in capital and annual operations and maintenance costs of $2.0 billion and $161 million year, respectively.

Chapter 4 addresses the life cycle GHG emissions impacts for a comparison of CSC partial-upgrading, full-upgrading and dilution options and explores the potential economic ramifications of these case study emissions results on the projected investment value. Through use of an integrated LCA model for oil sands pathways the emissions for the respective oil sands options are characterized with respect to two different current emissions policies, the Specified Gas Emitters Regulation of Alberta (SGER) and the Low Carbon Fuel Standard currently instated in California and British Columbia (LCFS), and a potential economy wide carbon tax.

The GHG emissions assessment suggests that CSC partial-upgrading with the re-integration of pitch has lower estimated WTW emissions per MJ of gasoline compared with CSC partial-upgrading where pitch is removed. However, CSC partial-upgrading with removed pitch has lower WTW emissions per barrel of extracted bitumen. Discrepancies in life cycle calculations are primarily attributed to how the respective calculations addressed diluent as part of the refined product slate and the removal of by products during upgrading.

When assessing the partial-upgrading pathway in comparison with an LCFS type of emissions policies, we see that the CSC partial-upgrader with the re-inclusion of pitch approached the current WTW California emissions threshold. However, this California LCFS also has a 15 g CO_2e/MJ gasoline threshold for WTR emissions which is only satisfied by the dilution case. With the additional decrease in LCFS emissions thresholds planned over time, it is unlikely that any of the oil sands pathways in their current form would be able to meet these future GHG emissions thresholds.

When assessing the partial-upgrading pathway in terms of SGER types of emissions policies, we see that CSC partial-upgrading without the inclusion of pitch has life cycle emissions which are comparable with the lowest life cycle emissions in the case study from coking full-upgrading. CSC partial-upgrading also has lower upgrading stage emissions compared with hydrocracking and coking full-upgrading. Assuming current environmental assessment structure of the SGER and assuming that the products are sent to a refinery out of province, this case study evaluation found that CSC partial-upgrading could avoid approximately 600 and 1,000 kilotonnes of GHG per year for a 100,000 bpd compared with conventional coking and hydrocracking upgraders, respectively. If a 15$ per tonne of CO_2e tax was assumed, this GHG emissions avoidance would translate to approximately $9M and $15M tax savings annually. However, the range of estimates for this process suggested that a high impact scenario (intended to represent potential system inefficiencies when industrially scale) could approach the same stage specific emissions as coking upgrading while low impact emissions (intended to represent potential process optimization when industrially scaled) estimates suggest for the potential additional reduction of approximately 300 kilotonnes per year compared with current upgrading technologies.

For direct economic comparison of the partial-upgrading pathway with current dilution and full-upgrading options under an economy wide carbon tax an example case study comparison was completed. The case study found that the NPV of the CSC partial-upgrading pathways are most significantly affected by the project market price for the upgraded product (partial-SCOs). The CSC partial-upgrading process, which included pitch, was significantly more affected by changes in projected price of diluent compared with CSC partial-upgrading without the inclusion of pitch. The relative effect of the capital cost of the partial upgrader was found to be approximately twice as influential on the CSC partial-upgrading NPV compared with annual operations and maintenance costs.

The economic comparison with coking and dilution options found that stringent carbon prices could suggest that CSC partial-upgrading without the re-incorporation of pitch material to be the higher valued investment. This study found the switchover from the dilution investment to a preference for the CSC partial-upgrading occurred at an economy wide GHG price of $90/ tonne CO_2e when a 10% discount rate was applied. This study showed the CSC partial-upgrading without pitch pathway to have a higher NPV than dilbit at lower GHG prices, under a lower discount rate. For example, the CSC partial upgrading without pitch becomes the preferred investment option at a GHG price of $80 per tonne assuming an 8% discount rate. However, at lower discount rates coking full-upgrading can surpass CSC partial-upgrading when even more stringent carbon prices are assumed. For example, the coking full-upgrading option became the preferred investment pathways above $145 per tonne assuming an 8% discount rate.

5.2 Research Contributions

5.2.1 LCA Emissions Literature and Contributions

This thesis develops framework for early stage evaluation of oil sands pathways which can be adapted or expanded upon to investigate different emissions policies and market conditions or study additional oil sands pathways. Improved understanding of GHG emissions impacts of emerging energy systems at an early stage can be used to project industrial level performance with current pathways as well as direct further development efforts. Methodological development for the evaluation of an emerging pathway involved the development of a framework which considered emissions impacts based on pilot plant studies and estimates of industrial scale process requirement. Through characterization of the emerging catalyst preparation and CSC upgrading process units and product partial-SCOs at a pilot plant scale along with use of simulation modeling, industrial estimates and an integrated LCA model for estimating WTW GHG emissions impacts, this assessment was able to estimate industrial scale emissions impacts for use in comparative case studies.

This thesis also contributes to the further development of the life cycle assessment WTW integrated model. The inclusion of the CSC partial-upgrading pathways allows this model to be linked to established models for estimating upstream and downstream processes, such as extraction or refining, and allows for direct comparison with current model estimates. Additionally, this improves upon the previous characterization of upgrading estimates through development of a process unit based model for the estimation in contrast to the current model which relies on specific indicators such as process gas, hydrogen requirements and flared hydrocarbons. Process unit based modeling not only better identifies process requirements for the partial-upgrading process, based on mass flow throughout the upgrader, but also develops a framework for future assessment of process unit based modeling for upgrading and dilution pathways. Additionally, the characterization of the CSC partial-SCO was also included in the refinery model for future emissions pathway comparisons.

5.2.2 Energy Systems Investment Analysis Contributions

The economic evaluation of the internalization of environmental costs for the direct comparison of oil sands pathways was accomplished through developing a cost-benefit framework for the energy systems investment decisions. Through use of industrial estimates for costs such as capital and operational costs, as well as projected crude price forecasts, a case study was developed for the comparison of these energy system pathways. Energy system investment decisions are then informed with the development of an economic cost-benefit model which incorporated the case study for the emissions impacts of the dilution and upgrading pathways with current or prospective environmental policies. This economic assessment framework also included the quantification of taxes and royalties for Alberta based operations.

Through sensitivity analysis with respect to the NPV of the CSC partially-upgrading pathways, this economic framework was able to directly correlate the effects of changing operational factors, such as crude price, to the investment value of the project. This framework allows for the direct comparison of the NPV effects of operational or economic factors between these oil sands pathways to better inform decision making in stakeholders.

5.3 Consideration for Future Work

5.3.1 Further Improvements of Industrial Scale Projections

The HYSYS® model developed for estimating industrial scale process requirements could be further improved upon through improved characterization of crude properties and accounting for all process units in a single interconnect model. Through more in-depth modeling, such as characterizing reaction kinetics, the entire process could be better analyzed to capture process efficiency improvements in the pilot plant design before scaling up. Capturing an integrated process can be used to inform of the interdependencies of process units and crude properties throughout the upgrading scheme.

Further development efforts for the assignment of process requirements, such as electrical or fuel, to specific process streams could more clearly identify and distinguish these streams and could be used to better allocate emissions to specific products. This would further improve upon emissions allocation assumption from this study to better reflect emissions policies pertaining to a specific fuel product (thus better representing policies pertaining to a single product type such as LCFS). Through better understanding of these intermediary processing steps this could allow for more transparent characterization of the emissions impacts.

Development of a larger scale integrated plants is important for continued development of this emerging partial-upgrading process. This demonstration plant would be used to better inform with respect to the effects of integrating process units for on-stream processing (for example, eliminating time between catalyst preparation and upgrading which could affect catalyst activity) as well as being useful in assessing the effect of different designs and technology choices, such as a small 'topper' design for atmospheric distillation or SDA with pentane as solvent, on overall emissions. The larger scale plant could process higher volumes and therefor produce sufficient quantities for crude fractionation and analysis, to allow for better representation in the life cycle emissions estimate model. Additionally, this facility could better evaluate the reproducibility of the pilot plant results as well as evaluate the effect of different bitumen feedstocks on the performance of CSC partial-upgrading. This larger scale plant would be useful in verification and further development of the emissions estimates and analysis framework established in this thesis.

5.3.2 Future Research Questions

The developed cost-benefit framework for comparing oil sands pathway options can be further developed with more pathway options and policy implications. Further development of this economic evaluation would allow for comparison under scenarios for crude oil prices, energy costs, capital and operational costs, and discount rates under varied emissions policies. Current economic modeling assumes factors such as a constant royalty and tax scheme throughout the project lifetime; factors which could additionally be explored. This case study does not consider a combination of pathway options, such as dilution for half of the project lifetime before building an upgrader, which could be opted for in the case of a significant increase in diluent price. Additionally, this model could be further developed for other partial or full-upgrading options and pathways, consideration for varied diluents such as SCO or natural gas condensate as well as accounting for by-products such as pitch or coke. For example, pitch can be investigated for current market values and subsequent emissions impacts as well as consideration for the possibility of enhance asphaltene upgrading methods which could soon be developed economically. Energy systems choices, from the use of by-product pitch as an energy source to solar energy production, as well as the option of emissions mitigation technologies could be further investigated for LCA emissions impacts and inclusion in a cost-benefit framework. Finally, the consideration for infrastructure development costs which were not considered in the scope of this study, such future pipeline transportation infrastructure or the use of crude oil tankers for accessing international markets, could also be used to tailor this analysis to future projects. The development of further economic assessment could better inform these investment decisions for stakeholders and policy makers.

This thesis highlighted a number of issues or discrepancies between the evaluation methods for representing these processes and industrial practices, such as pilot plant batch processing and real options for produced by-products. This study assumes that the upgraded products and specific reaction conditions established from the pilot plant are representative of industrial scale processing when the use of batch processing for the catalyst preparation process unit and the CSC upgrading process unit allowed for additional time when the feedstock is at rest which may have affected catalyst agglomeration and sedimentation. Therefore, the pilot plant study may not be directly representative of the performance when scaled to an on-stream process. The use of on-stream process units would allow for this pathway to be better characterized for emissions impacts of an integrated process and further development of these process units to a larger scale could be used to better represent the projected emissions impacts. Additionally, the representation of a single crude type being sent through the pipeline and refined independently is not representative of the crude batches that are simultaneously transported and refined. The effects of batching these crudes could be further explored for effects on pipeline transportation and refining to better understand how to best represent industrial processing.

Exploring the effects of these emissions policies for addressing by-products from an upgrader or diluent recycling (where diluent is being refined into end products) can be used to better understand the implications of emissions allocation methods. The assessment of emissions based on the by-products from upgrading can have contrasting effects on the calculation methods used for different policies, as shown with the GHG emissions calculations with respect to the two functional units. Additional studies related to the real option for these upgrader by-products could be developed as part of the established cost benefit framework to understand the price of the by-product, based on process emissions implications and policy costs. Exploring the option of assigning downstream emissions for these by-products, for uses such as an energy source or simply pulverization and burial, would add transparency to these emissions assessments.

Comparison with other partial-upgrading and other technologies would also be greatly beneficial in benchmarking the CSC partial-upgraders against other potential partial-upgrading technologies. Though partial-upgrading pathways are characterized by a partial-SCO with similar density and viscosity properties to the CSC partial-SCOs, there can be significantly different process units and configurations for the respective partial-upgrading processes. It is likely that the stage specific emissions from the partial-upgrading process, as well as the qualities of the partial-SCO, such as hydrogen content, will yield varied environmental impacts of these other partial-upgrading technologies. Through characterizing further processes we can better understand the potential for partial-upgrading in comparison with current oil sands pathways as well as identify specific processes, like removal of by-products, which significantly impact these processes.

The framework for estimating industrial scale impacts could also be used to look at the perspective of smaller scale operations for exploration or development purposes. For example, using this form of partial-upgrading may be a viable option in the case of remote operations where infrastructure development for diluent or another form of crude transportation, such as rail, would be difficult and costly.

Finally, this integrated LCA model can be further developed to account for environmental impacts and consequences beyond GHG emissions. Consideration for other environmental factors, such as land use or water impacts, could be used to more completely characterize these oil sands pathways. Additionally, development of the integrated model to account for these environmental impacts could be used to better inform future policy making applied beyond GHG emissions for oil sands operations.

5.4 Take Home Message for Stakeholders and Policy Makers

Impacts of environmental regulation and incentivising GHG emissions reductions for the oil sands industry will play an increasingly important role in future energy systems investments. However, this study also showed that the way in which emissions regulations are imposed needs to be carefully considered to ensure it incentivises total life cycle reductions as opposed to stage specific reductions which could have downstream impacts. Therefore, further development of these life cycle studies will better identify pathways that have decreased overall environmental impacts.

The cost-benefit analysis suggests CSC partial-upgrading pathway could be the preferred investment option in comparison with current oil sands pathways, under certain economy wide GHG emissions policy conditions and future market prices. The case study for the investment option of the oil sands pathways found that the CSC partial-upgrading pathway could be seen as a higher value investment in light of certain GHG emissions policies, however, dilution is still the preferred investment a lower carbon prices. CSC partial-upgrading is also found to have a higher investment value in comparison with coking full-upgrading unless a low discount rate and high economy wide carbon taxes are assumed. Further development of these economic evaluations with further deliberation for projected prices of crudes, utilities, royalties, taxes and carbon policies could increase the benefit of this form of cost-benefit analysis and lead to the preference for pathways with lower GHG emissions impacts despite having a lower project value under current emissions policies.

For low carbon fuel types of policies, such as the ones in California and British Columbia, we can see that this CSC partial-upgrading with pitch pathway could have comparable emissions to the dilution pathways [State of California, 2006. Province of BC, 2013]. Current California LCFS restrict the potential for oil sands products in their market due to WTW emissions threshold which is currently comparable with the emissions for dilution and CSC partial-upgrading with pitch, as established in this case study. However, this emissions threshold is annually decreasing and therefore it is unlikely that oil sands pathways will be able to meet future emissions thresholds without significant changes to operations such as their energy systems or use of carbon capture technologies. Additionally, the use of a WTR emissions threshold for the California LCFS limits the potential for the CSC partial-upgrading pathway in comparison with dilution options due to additional emissions associated with partial-upgrading, despite comparable life cycle emissions results. Therefore, this form of carbon policy is not only restrictive for oil sands products but it additionally incentivizes reductions in processing prior to the refinery.

Current Alberta based GHG emissions legislation, SGER, is applicable to all high emitting operation in the province [Alberta Environment, 2013]. This form of policy in its current form indicated that the CSC partial-upgrading process has significant potential for reduction in annual processing emissions compared with full-upgrading options. However, current SGER are applied to large scale emissions facilities and therefore would be applicable to any type of upgrading facility despite electing to use a partial-upgrading with significantly lowered upgrading stage emissions compared with hydrocracking and coking full-upgrading. The cost-benefit analysis suggests that the application of an economy wide carbon tax, where downstream emissions reductions of a pathway could be economically compensated, can affect the investment decisions related to oil sands developments.

A significant benefit of this form of economy wide carbon taxation is ease of industrial implementation, however, swift implementation has the potential to cause these forms of policies to be later revoked. For example, Australia's decision following 2013 elections was to repeal the Clean Energy Act 2011 legislation, that establishes carbon pricing mechanism, in lue of emissions reduction strategies such as a 'Direct Action Plan' to source low cost emissions reductions and development of the 'Emission Reduction Fund' [Australian Government Clean Energy Regulator, 2013].

With respect to the Alberta Governments position to incentivise value added upgrading which occurs in the province, this thesis found that high emissions taxes under an economy wide emissions policy would result in partial-upgrading or full-upgrading pathways to be preferred over dilution at low depreciation rates. Therefore, if the province shared in the risks associated with these upgrading options through sharing equity in upgrading projects it would further increase the investment value of these options. Additionally, economical CO_2 removal and storage, credits for upgraders, adjusting transportation tolls or subsidies for unprocessed-bitumen could also increase industrial adoption of upgrading pathways. However, the effect of emissions policies are insignificant when only Alberta based processing is considered and therefore wider reaching policies, such as an economy wide carbon tax, would be required for emissions reductions to further impact these investment decisions. This case study showed the potential for an economy-wide carbon tax to cause CSC partial-upgrading to be the preferred investment option under certain carbon prices (GHG prices between \$80 - \$145 per tonne CO_2e assuming an 8% discount rate and < \$90/ tonne CO_2e assuming a 10% discount rate).

5.5 Outlook for CSC Partial-Upgrading

In conclusion, this thesis has shown that this energy system investment option has several advantages compared with traditional dilution and full-upgrading options. This assessment found stage specific emissions from partial-upgrading to be significantly reduced compared with full-upgrading which could reduce emissions costs under current SGER emissions policy (31 kg CO_2e/bbl Bitumen vs 47 and 57 kg CO_2e/bbl Bitumen for Coking and Hydrocracking pathways, respectively). Additionally, the small scale investment of the partial-upgrading pathways resulted in a significantly higher NPV for this pathway compared with the case study for coking full-upgrading. Reduced emissions impacts of the partial-upgrading pathway, with respect to the dilution pathway, is seen to potentially result in a higher NPV under certain economy wide pricing schemes. Therefore, the economic case for CSC partial-upgrading investment as the preferred oil sands pathway could be incentivised by carbon policies and future crude prices.

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Appendix A. Simulated Distillation for VGO Upgrading

Figure A1. Simdist for thermally converted VGO at 430°C, 2hr^{-1}

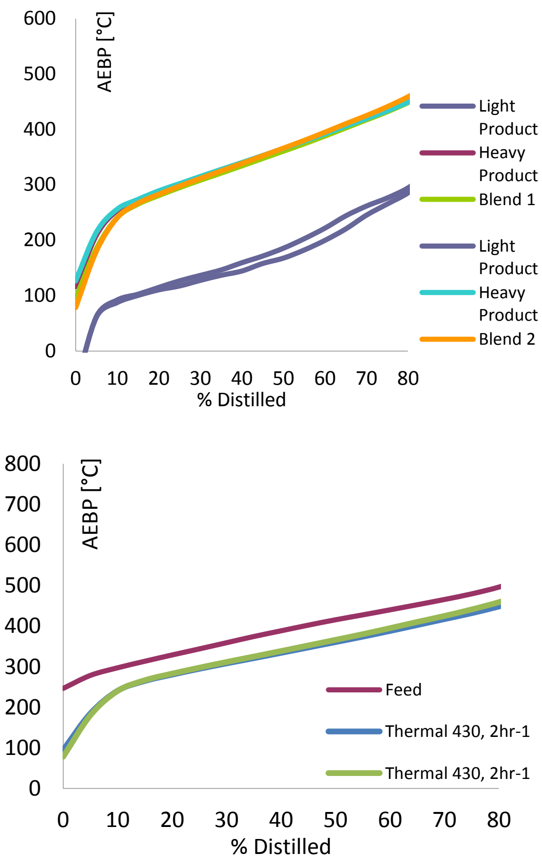


Figure A2. Simdist for CSC converted VGO at 440°C, 2hr^{-1}

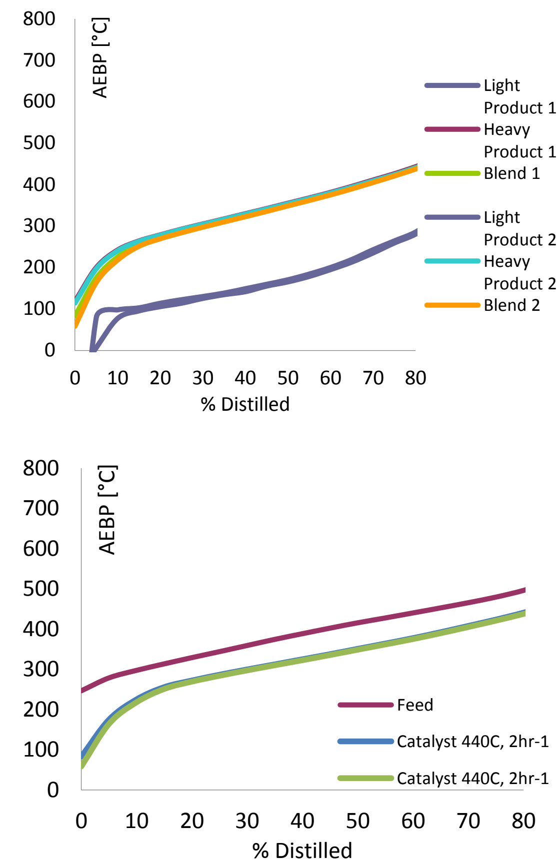


Figure A3. Simdist for CSC converted VGO at 445°C, 2 hr^{-1}

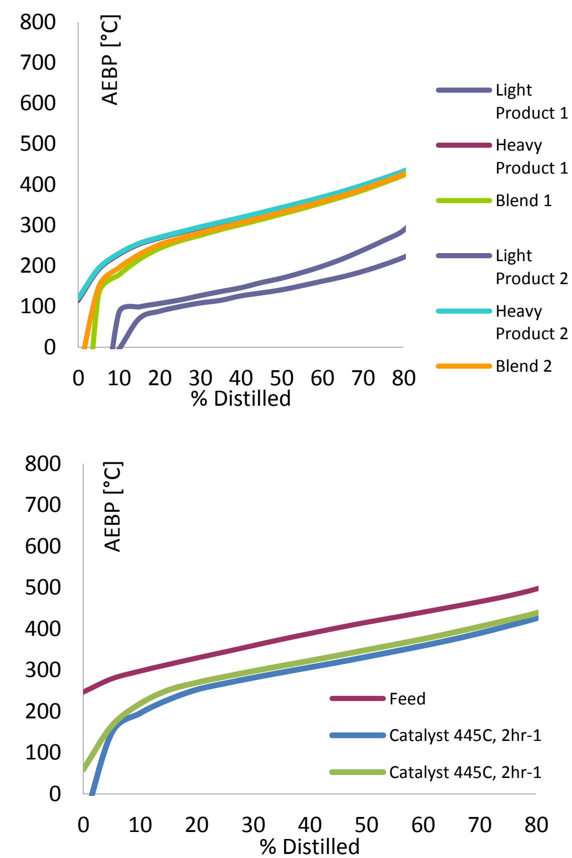


Figure A4. Simdist for CSC converted VGO at 440°C, 1.7 hr^{-1}

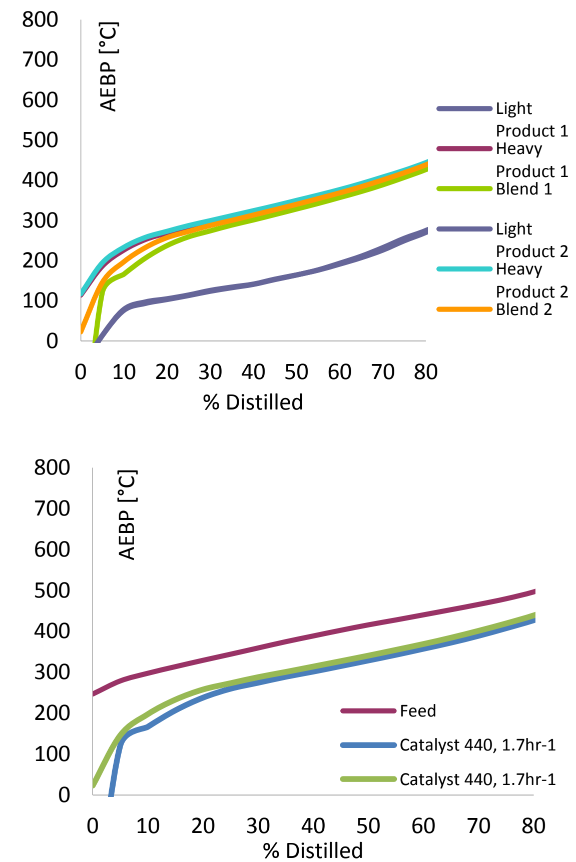


Figure A5. Simdist for CSC converted VGO at 435°C, 1.7 hr^{-1}

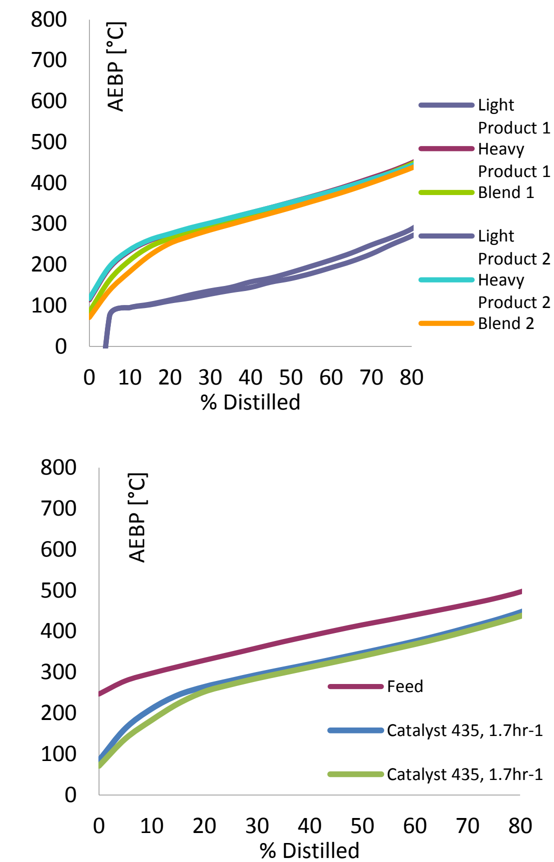
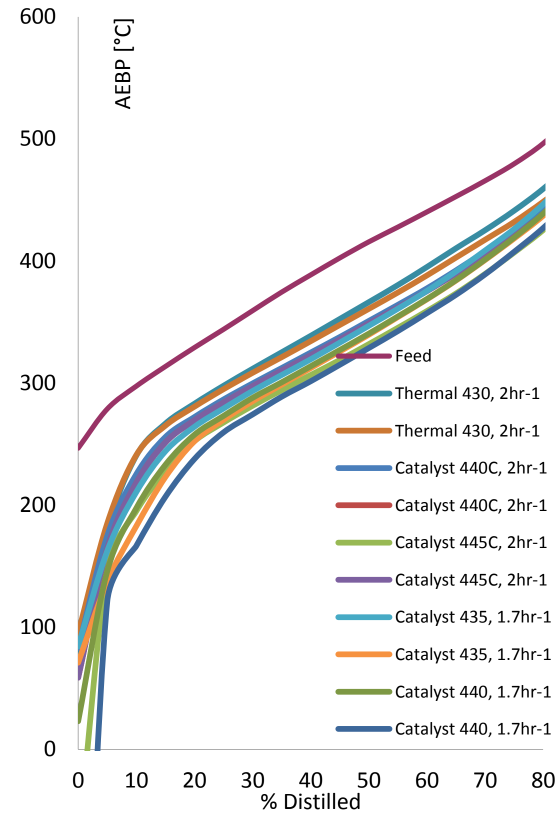


Figure A6. Simdist for thermally and CSC converted VGO



Appendix B. Simulated Distillation for DAO Upgrading

Figure A7. Simdist for thermally converted DAO at 425°C, $3hr^{-1}$

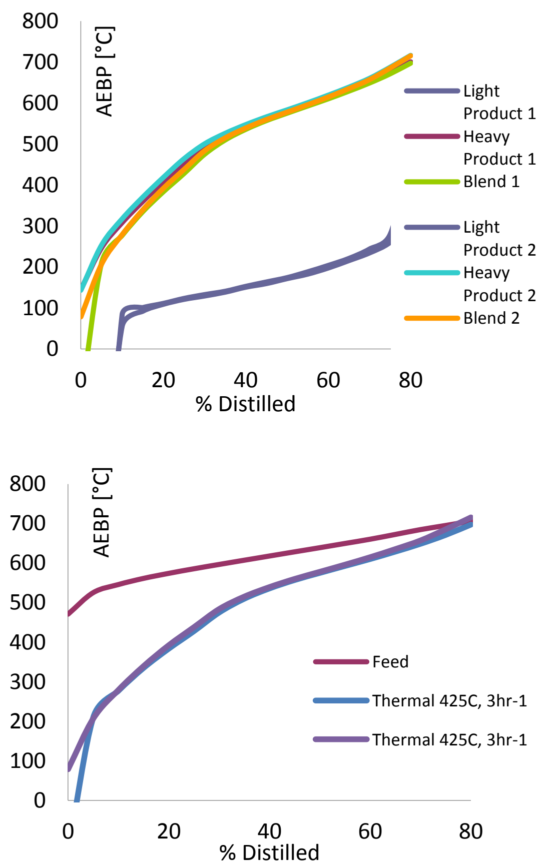


Figure A8. Simdist for CSC converted DAO at 435°C, 3 hr^{-1}

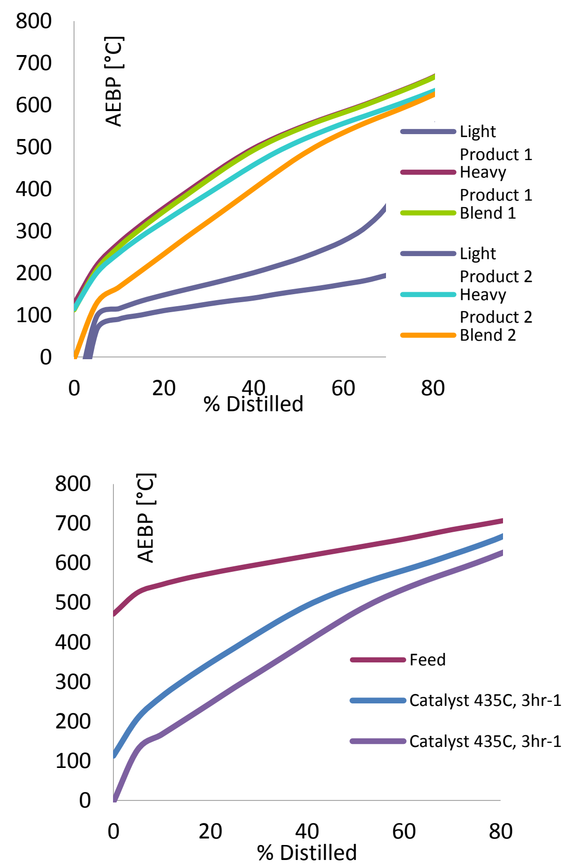


Figure A9. Simdist for CSC converted DAO at 440°C, 3 hr^{-1}

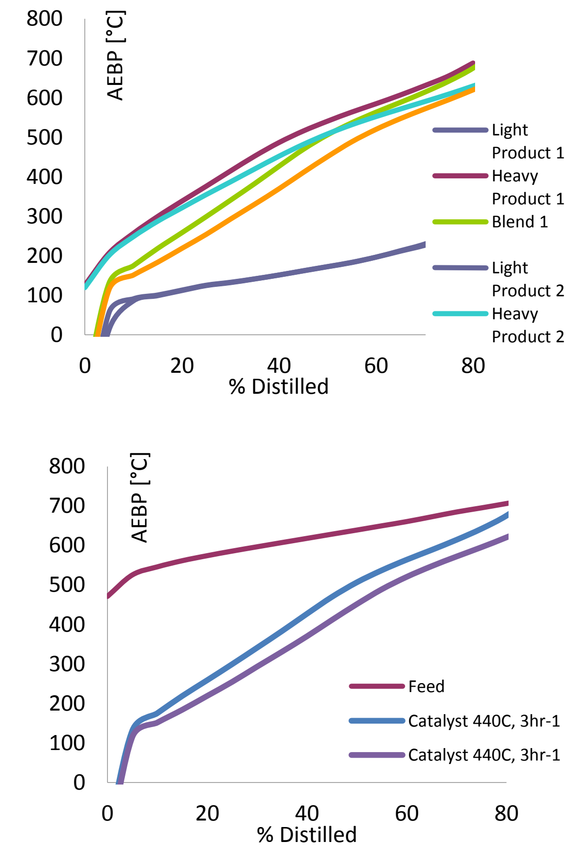


Figure A10. Simdist for CSC converted DAO at 435°C, 3.2 hr^{-1}

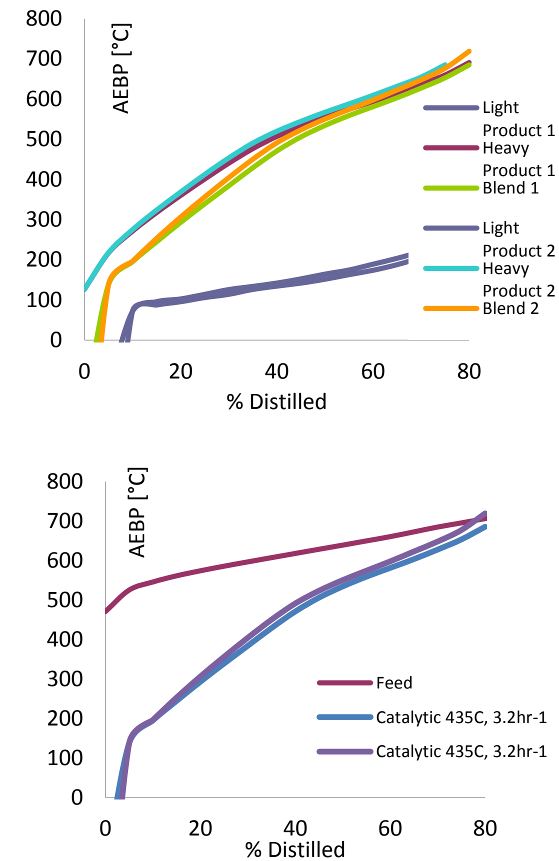


Figure A11. Simdist for CSC converted DAO at 440°C, 3.2 hr^{-1}

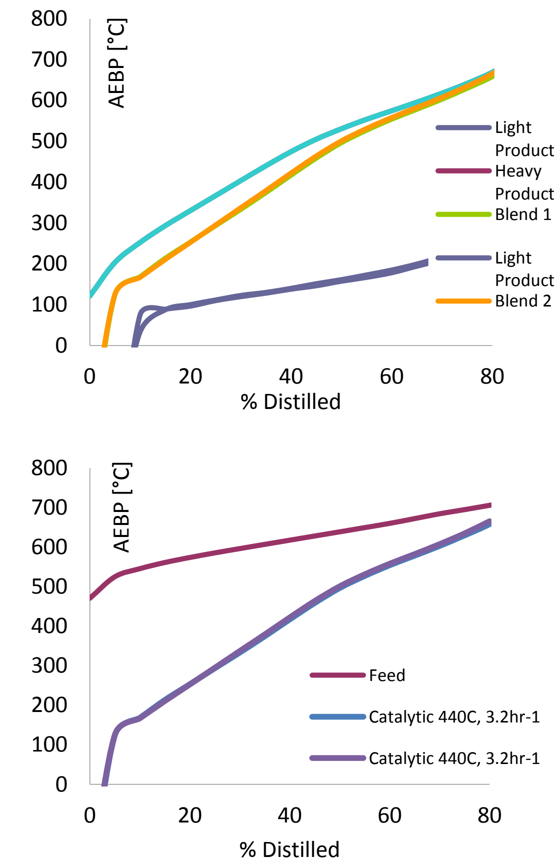
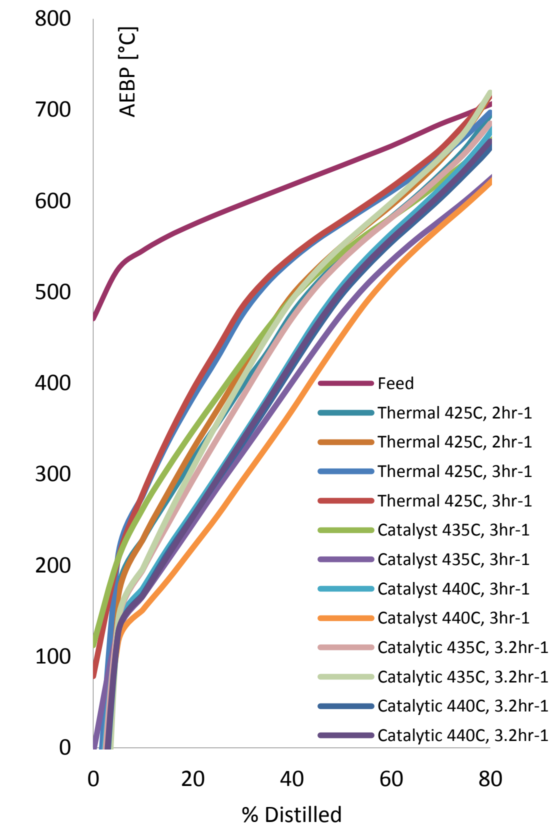


Figure A12. Simdist for thermally and CSC converted DAO



Appendix C. Stability Test Results

All images taken at 40x magnifications unless otherwise stated

Figure A13 Stability test (P-value 125) for thermal converted DAO 425^{o}C, 3hr^{-1}-2

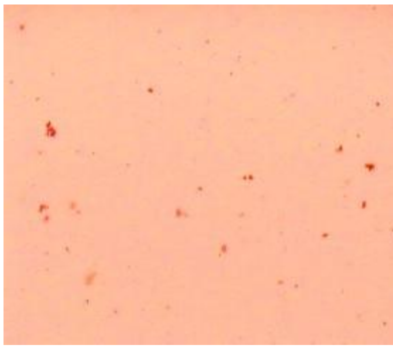


Figure A14 Stability test (P-value 115) for thermal converted DAO 425^{o}C, 3hr^{-1}-1

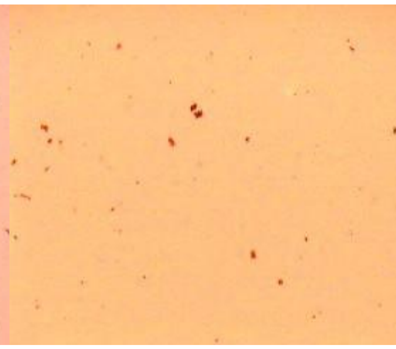


Figure A15 Blank DAO with catalyst before upgrading-1

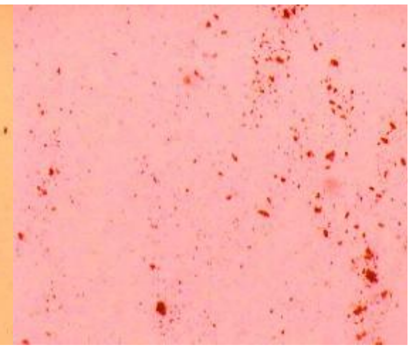


Figure A16 Blank DAO with catalyst before upgrading-1 (10x magnification)

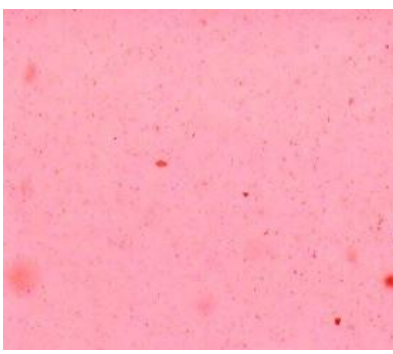


Figure A17 Stability test (P-value 120) for CSC converted DAO 435^{o}C, 3hr^{-1}-1

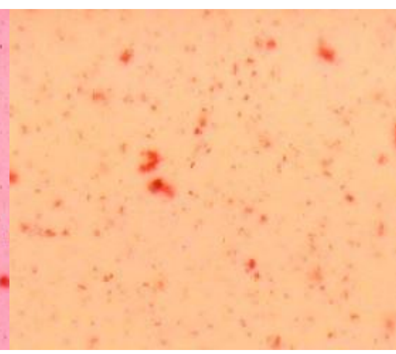


Figure A18 Stability test (P-value 120) for CSC converted DAO 435^{o}C, 3hr^{-1}-2

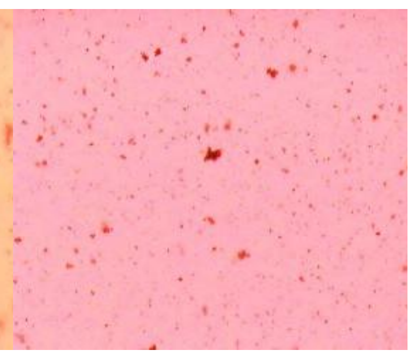


Figure A19 Stability test (P-value 115) for CSC converted DAO 440^{o}C, 3hr^{-1}-1

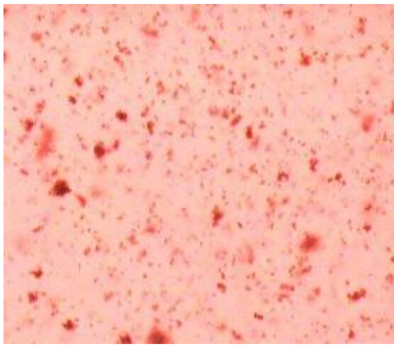


Figure A20 Stability test (P-value 115) for CSC converted DAO 440^{o}C, 3hr^{-1}-2

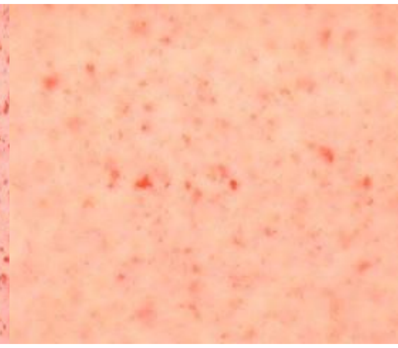


Figure A21 Stability test (P-value 115) for CSC converted DAO 435^{o}C, 3.2hr^{-1}-1

(10x magnification)

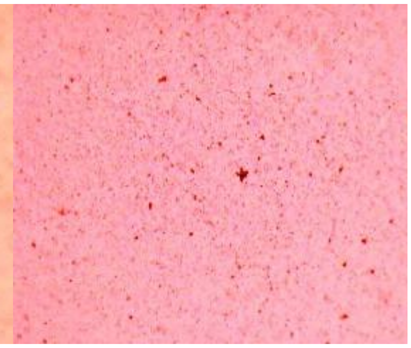


Figure A22 Stability test (P-value 120) for CSC converted DAO 435^{o}C, 3.2hr^{-1}-2

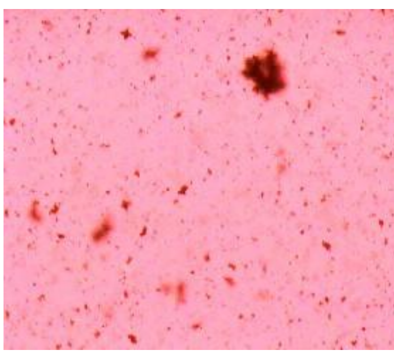


Figure A23 Stability test (P-value 120) for CSC converted DAO 440^{o}C, 3.2hr^{-1}-1

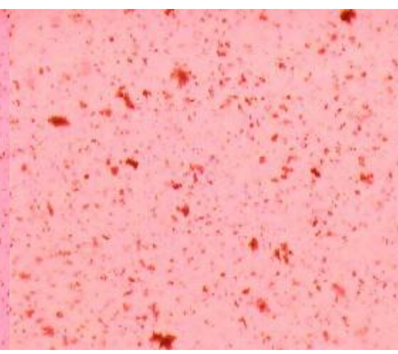
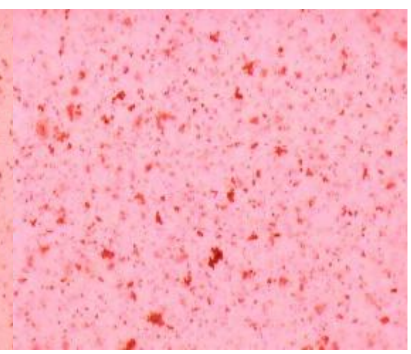


Figure A24 Stability test (P-value 120) for CSC converted DAO 440^{o}C, 3.2hr^{-1}-2



Appendix D. Micro Carbon Residue (MCR) Test Results

Table A1 MCR testing results

Sample Name	Sample in Tube (g)	Heated to 500°C in Ni	Heated to 500°C in Air	Sample Mass (µg)	% Micro Carbon	Standard Deviation	Avg % M.C.
Standard	2.31421	2.28538	2.2823	31.96	9.65	-	**9.65**
VGO feed	2.29612	2.21721	2.21714	79	0.09	0.09	**0.15**
	2.29003	2.2166	2.21644	73.59	0.22		
Thermal 430°C, $2hr^{-1}$, MB1	2.27552	2.21434	2.21318	62.38	1.86	0.04	**1.89**
	2.30686	2.2381	2.23676	70.08	1.91		
Thermal 430°C, $2hr^{-1}$, MB2	2.28874	2.21503	2.214	74.65	1.38	0.05	**1.34**
	2.29064	2.21177	2.21073	79.87	1.30		
Catalytic 440°C, $2hr^{-1}$, MB1	2.26588	2.18978	2.18778	78.12	2.56	0.06	**2.52**
	2.3355	2.24295	2.2406	94.92	2.48		
Catalytic 440°C, $2hr^{-1}$, MB2	2.25078	2.19411	2.1927	58.08	2.43	0.09	**2.36**
	2.30128	2.23062	2.22896	72.32	2.30		
Catalytic 445°C, $2hr^{-1}$, MB1	2.30862	2.23299	2.2304	78.67	3.31	0.58	**2.90**
	2.29869	2.22255	2.2206	78.9	2.50		
Catalytic 445°C, $2hr^{-1}$, MB2	2.32	2.25183	2.24999	70.45	2.63	0.47	**2.96**
	2.22935	2.18443	2.1829	46.6	3.29		
Catalytic 440°C, $1.7hr^{-1}$, MB1	2.30242	2.24824	2.24649	55.95	3.13	0.15	**3.03**
	2.2718	2.20136	2.19924	72.91	2.92		
Catalytic 440°C, $1.7hr^{-1}$, MB2	2.31593	2.25425	2.25216	63.95	3.28	0.33	**3.04**
	2.31021	2.24476	2.24287	67.79	2.81		
Catalytic 435°C, $1.7hr^{-1}$MB1	2.25935	2.17213	2.1695	90.15	2.93	0.02	**2.91**
	2.31179	2.24937	2.24751	64.33	2.89		
Catalytic 435°C, $1.7hr^{-1}$MB2	2.29258	2.22547	2.22372	68.96	2.54	0.03	**2.52**
	2.2971	2.22093	2.21898	78.33	2.50		

Appendix E. Gas Chromatography Data Acquisition

Table A2 Gas chromatography data from CSC of VGO 435°C, 1.7hr^{-1}

Component	Retention	Area	External	Norm area %
Hydrogen MS	0.486	0.2676	0.0031	0.0743
H_2S	2.496	1023.653	0.0057	0.1389
Methane HAYD	3.316	60.7956	2.7747	67.3809
CO_2	4.283	7.1676	0.1779	4.321
Ethylene HAYD	5.493	4.5258	0.1035	2.5137
Propylene	8.96	6.6128	0.1158	2.8112
Propane	9.18	48.3668	0.5941	14.4258
i-Butane	11.59	12.2296	0.123	2.9871
n-Butane	11.86	27.6732	0.2176	5.2839
i-Pentane	14.286	5.431	0.0026	0.0632

Table A3 Gas chromatography data from CSC upgrading of DAO 440°C, 3.2 hr^{-1}

Component	Retention	Area	External	Norm area %
Hydrogen MS	0.766	0.945	0.0108	0.0523
H_2S	5.022	6733.611	0.0376	0.1822
Methane HAYD	3.22	250.0556	11.4126	55.2803
CO_2	4.23	58.3734	1.4491	7.0194
Ethylene HAYD	5.456	19.1664	0.4384	2.1234
Ethane HAYD	5.986	207.3132	4.3104	20.8786
Propylene	8.93	43.94	0.7692	3.7259
Propane	9.13	144.4954	1.7747	8.5964
i-Butane	11.606	17.108	0.1721	0.8335
n-Butane	11.866	34.0352	0.2676	1.2963
i-Pentane	14.3	5.0736	0.0024	0.0118

Appendix F. Crude Assays Built into the LCAOS Model

Table A4. Crude assay for CSC with pitch for the refinery emissions modeling

CSC w A		Final Boiling Point	85 °C	180 °C	290 °C	343 °C	399 °C	454 °C	525 °C	525+ °C	399+ °C
Property		Full Crude	C5s	Naphtha	Kerosene	Diesel	AGO	LVGO	HVGO	VR	AR
Vol Flow	bpd	100000	2282	19458	31983	3954	6959	5599	6376	23388	35373
Vol Flow	m^3/d	15900	363	3094	5085	629	1107	890	1014	3719	5624
Mass Flow	kg/d	14707500	222214	2414449	4420720	571406	1027473	848644	996511	4206082	6051237
Sulphur	wt%	2.8	0	0.5	1.2	1.7	2.1	2.4	2.9	6.1	5.1
Nitrogen	mass ppm	2700	0	0	0	221	518	925	1541	2726	1958
API gravity	°API	21	86	75	29	25	20	15	12	2	6
Density	kg/m^3	925	650	685	880	902	933	967	983	1125	1075
Hydrogen	wt%	12	16.4	15.5	12.5	12.3	11.4	10.8	10.55	10	10.1
MCR	wt%	10.1	0	0	0	0	0	0	0	35	25
Characterization Factor	Kw (Approximate)	12	13	12	12	11	11	11	11	11	11
Tb(50%) weight basis	[°C]	333.8									

Table A5. Crude assay for CSC without pitch for the refinery emissions modeling

CSC w/o A	Final Boiling Point		85 °C	180 °C	290 °C	343 °C	399 °C	454 °C	525 °C	525+ °C	399+ °C
Property		Full Crude	C5s	Naphtha	Kerosene	Diesel	AGO	LVGO	HVGO	VR	AR
Vol Flow	bpd	100000	2880	16349	24350	13830	9048	6878	5681	20983	33575
Vol Flow	m^3/d	15900	458	2600	3872	2199	1439	1094	903	3336	5338
Mass Flow	kg/d	14707500	280691	2030190	3368149	1999923	1336790	1043234	888549	3759973	5691757
Sulphur	wt%	2.7	0	0.5	1.2	1.7	2.1	2.4	2.9	6	4.8
Nitrogen	mass ppm	2550	0	0	0	221	518	925	1541	2726	1958
API gravity	°API	21	86	75	29	25	20	15	12	2	6
Density	kg/m^3	925	650	685	880	902	933	967	983	1125	1075
Hydrogen	wt%	11.7	16	15.4	12.3	12.1	11.2	10.6	10.4	9.9	10
MCR	wt%	6.2	0	0	0	0	0	0	0	24	16
Characterization Factor	Kw (Approximate)	12	13	12	12	11	11	11	11	11	11
Tb(50%) weight basis	[°C]	342									

Table A6. Crude assay for diluted bitumen for the refinery emissions modeling

Dilbit		Final Boiling Point	85 °C	180 °C	290 °C	343 °C	399 °C	454 °C	525 °C	525+ °C	399+ °C
Property		Full Crude	C5s	Naphtha	Kerosene	Diesel	AGO	LVGO	HVGO	VR	AR
Vol Flow	bpd	100000	1	20937	24178	5228	7672	4248	6985	30751	41987
Vol Flow	m^3/d	15900	0	3329	3844	831	1220	675	1111	4889	6676
Mass Flow	kg/d	14707500	98	2594546	3337428	754528	1131303	642964	1090200	5156433	6889597
Sulphur	wt%	3	0.3	0.5	1.1	1.6	2.1	2.6	3.3	5.9	5.3
Nitrogen	mass ppm	2650	0	0	0	221	518	925	1541	2726	1958
API gravity	°API	21	86	75	29	25	20	15	12	2	6
Density	kg/m^3	925	650	685	880	902	933	967	983	1100	1065
Hydrogen	wt%	11.7	16.4	15.5	12.5	12.3	11.4	10.8	10.55	9.9	10
MCR	wt%	8.8	0	0	0	0	0	0	0	25	19
Characterization Factor	Kw (Approximate)	12	13	12	12	11	11	11	11	11	11
Tb(50%) weight basis	[°C]	430.3									

Appendix G. Economic Analysis Framework – Present Value Cash Flow (Schedule 1)

Note: economic results are reflective of case study findings assuming a 10% discount rate and no carbon taxes applied

Table A7 Dilution present value cash flow

Year	Operating Revenue (4)	Income Tax (4)	Yearly Capital Additional(5)	Yearly Cash Flow	Cumulative total cash flow	Present Value of yearly cash flow	Cumulative total PV of yearly cash flow
0	$-	$-	$5,274,050,189	$(5,274,050,189)	$(5,274,050,189)	$(5,274,050,189)	$(5,274,050,189)
1	$2,123,268,954	$80,984,577	$248,456,326	$1,793,828,051	$(3,480,222,137)	$1,630,752,774	$(3,643,297,415)
2	$2,162,100,054	$351,311,607	$248,456,326	$1,562,332,122	$(1,917,890,015)	$1,291,183,572	$(2,352,113,843)
3	$2,200,203,848	$413,272,975	$248,456,326	$1,538,474,546	$(379,415,469)	$1,155,878,698	$(1,196,235,145)
4	$1,743,172,102	$318,917,220	$248,456,326	$1,175,798,555	$796,383,086	$803,086,234	$(393,148,911)
5	$1,768,675,096	$354,950,678	$248,456,326	$1,165,268,093	$1,961,651,179	$723,539,806	$330,390,895
6	$1,793,573,923	$383,649,529	$248,456,326	$1,161,468,068	$3,123,119,248	$655,618,445	$986,009,340
7	$1,817,868,581	$406,803,623	$248,456,326	$1,162,608,632	$4,285,727,880	$596,602,058	$1,582,611,398
8	$1,841,559,071	$425,755,348	$248,456,326	$1,167,347,397	$5,453,075,277	$544,576,176	$2,127,187,574
9	$1,864,645,393	$441,511,493	$248,456,326	$1,174,677,574	$6,627,752,851	$498,177,961	$2,625,365,535
10	$1,887,127,546	$454,827,152	$248,456,326	$1,183,844,069	$7,811,596,920	$456,423,136	$3,081,788,672
11	$1,909,005,531	$466,268,643	$248,456,326	$1,194,280,562	$9,005,877,482	$418,588,051	$3,500,376,723
12	$1,930,279,348	$476,260,707	$248,456,326	$1,205,562,316	$10,211,439,798	$384,129,306	$3,884,506,030
13	$1,950,948,996	$485,121,897	$248,456,326	$1,217,370,774	$11,428,810,571	$352,628,950	$4,237,134,980
14	$1,971,014,477	$493,091,131	$248,456,326	$1,229,467,020	$12,658,277,591	$323,757,093	$4,560,892,072
15	$1,990,475,788	$500,347,594	$248,456,326	$1,241,671,868	$13,899,949,460	$297,246,373	$4,858,138,445
16	$2,009,332,932	$507,025,678	$248,456,326	$1,253,850,928	$15,153,800,387	$272,874,494	$5,131,012,939
17	$2,027,585,907	$513,226,176	$248,456,326	$1,265,903,406	$16,419,703,793	$250,452,240	$5,381,465,179

18	$2,045,234,714	$519,024,680	$248,456,326	$1,277,753,708	$17,697,457,501	$229,815,236	$5,611,280,415
19	$2,062,279,353	$524,477,889	$248,456,326	$1,289,345,138	$18,986,802,639	$210,818,233	$5,822,098,648
20	$2,080,882,697	$530,255,556	$248,456,326	$1,302,170,815	$20,288,973,455	$193,559,394	$6,015,658,042
21	$2,113,850,519	$540,103,247	$248,456,326	$1,325,290,946	$21,614,264,401	$179,087,322	$6,194,745,365
22	$2,146,818,341	$549,879,183	$248,456,326	$1,348,482,832	$22,962,747,233	$165,655,686	$6,360,401,051
23	$2,179,786,163	$559,601,301	$248,456,326	$1,371,728,536	$24,334,475,769	$153,192,116	$6,513,593,167
24	$2,212,753,985	$569,283,058	$248,456,326	$1,395,014,601	$25,729,490,370	$141,629,692	$6,655,222,859
25	$2,245,721,807	$578,934,542	$248,456,326	$1,418,330,939	$27,147,821,309	$130,906,270	$6,786,129,128
26	$2,278,689,629	$588,563,322	$248,456,326	$1,441,669,981	$28,589,491,290	$120,963,973	$6,907,093,101
27	$2,311,657,451	$598,175,075	$248,456,326	$1,465,026,051	$30,054,517,341	$111,748,795	$7,018,841,896
28	$2,344,625,273	$607,774,056	$248,456,326	$1,488,394,891	$31,542,912,232	$103,210,287	$7,122,052,183
29	$2,377,593,095	$617,363,459	$248,456,326	$1,511,773,310	$33,054,685,542	$95,301,295	$7,217,353,478
30	$2,409,991,079	$626,780,425	$248,456,326	$1,534,754,328	$34,589,439,870	$87,954,550	$7,305,308,029

Table A8 CSC partial-upgrading with pitch present value cash flow

Year	Operating Revenue (4)	Income Tax (4)	Yearly Capital Additional(5)	Yearly Cash Flow	Cumulative total cash flow	Present Value of yearly cash flow	Cumulative total PV of yearly cash flow
0	$ -	$ -	$ 7,270,285,699	$ (7,270,285,699)	$ (7,270,285,699)	$ (7,270,285,699)	$ (7,270,285,699)
1	$ 1,757,260,507	$ -	$ 260,502,693	$ 1,496,757,814	$ (5,773,527,885)	$ 1,360,688,922	$ (5,909,596,777)
2	$ 1,805,732,732	$ -	$ 260,502,693	$ 1,545,230,039	$ (4,228,297,846)	$ 1,277,049,619	$ (4,632,547,158)
3	$ 1,853,640,403	$ 166,955,491	$ 260,502,693	$ 1,426,182,219	$ (2,802,115,626)	$ 1,071,511,810	$ (3,561,035,348)
4	$ 1,900,983,522	$ 309,054,016	$ 260,502,693	$ 1,331,426,812	$ (1,470,688,814)	$ 909,382,428	$ (2,651,652,920)
5	$ 1,947,762,087	$ 364,291,156	$ 260,502,693	$ 1,322,968,238	$ (147,720,576)	$ 821,459,188	$ (1,830,193,731)
6	$ 1,549,894,855	$ 280,163,176	$ 260,502,693	$ 1,009,228,986	$ 861,508,410	$ 569,683,452	$ (1,260,510,279)
7	$ 1,580,316,480	$ 312,425,585	$ 260,502,693	$ 1,007,388,202	$ 1,868,896,612	$ 516,949,434	$ (743,560,845)
8	$ 1,610,067,580	$ 338,633,507	$ 260,502,693	$ 1,010,931,380	$ 2,879,827,992	$ 471,606,949	$ (271,953,896)
9	$ 1,639,148,153	$ 360,251,951	$ 260,502,693	$ 1,018,393,509	$ 3,898,221,501	$ 431,898,262	$ 159,944,366
10	$ 1,667,558,201	$ 378,379,673	$ 260,502,693	$ 1,028,675,835	$ 4,926,897,336	$ 396,599,065	$ 556,543,431
11	$ 1,695,297,724	$ 393,840,741	$ 260,502,693	$ 1,040,954,290	$ 5,967,851,626	$ 364,848,128	$ 921,391,560
12	$ 1,722,366,720	$ 407,253,204	$ 260,502,693	$ 1,054,610,823	$ 7,022,462,449	$ 336,031,509	$ 1,257,423,069
13	$ 1,748,765,191	$ 419,080,602	$ 260,502,693	$ 1,069,181,896	$ 8,091,644,345	$ 309,703,911	$ 1,567,126,979
14	$ 1,774,493,136	$ 429,670,586	$ 260,502,693	$ 1,084,319,856	$ 9,175,964,201	$ 285,535,308	$ 1,852,662,287
15	$ 1,799,550,555	$ 439,283,898	$ 260,502,693	$ 1,099,763,963	$ 10,275,728,165	$ 263,274,749	$ 2,115,937,036
16	$ 1,823,937,448	$ 448,116,093	$ 260,502,693	$ 1,115,318,662	$ 11,391,046,827	$ 242,725,837	$ 2,358,662,873
17	$ 1,847,653,816	$ 456,313,836	$ 260,502,693	$ 1,130,837,287	$ 12,521,884,114	$ 223,730,129	$ 2,582,393,001
18	$ 1,870,699,658	$ 463,987,127	$ 260,502,693	$ 1,146,209,837	$ 13,668,093,951	$ 206,155,914	$ 2,788,548,916
19	$ 1,893,074,974	$ 471,218,467	$ 260,502,693	$ 1,161,353,813	$ 14,829,447,764	$ 189,890,629	$ 2,978,439,544
20	$ 1,916,734,670	$ 478,636,653	$ 260,502,693	$ 1,177,595,324	$ 16,007,043,088	$ 175,042,041	$ 3,153,481,586
21	$ 1,953,323,438	$ 489,665,051	$ 260,502,693	$ 1,203,155,694	$ 17,210,198,783	$ 162,583,116	$ 3,316,064,701

22	$ 1,989,912,206	$ 500,589,035	$ 260,502,693	$ 1,228,820,478	$ 18,439,019,261	$ 150,955,648	$ 3,467,020,349
23	$ 2,026,500,974	$ 511,434,708	$ 260,502,693	$ 1,254,563,572	$ 19,693,582,833	$ 140,107,349	$ 3,607,127,698
24	$ 2,063,089,742	$ 522,221,649	$ 260,502,693	$ 1,280,365,399	$ 20,973,948,233	$ 129,989,863	$ 3,737,117,561
25	$ 2,099,678,510	$ 532,964,541	$ 260,502,693	$ 1,306,211,276	$ 22,280,159,509	$ 120,558,074	$ 3,857,675,634
26	$ 2,136,267,278	$ 543,674,395	$ 260,502,693	$ 1,332,090,190	$ 23,612,249,698	$ 111,769,631	$ 3,969,445,265
27	$ 2,172,856,046	$ 554,359,471	$ 260,502,693	$ 1,357,993,881	$ 24,970,243,580	$ 103,584,629	$ 4,073,029,894
28	$ 2,209,444,814	$ 565,025,964	$ 260,502,693	$ 1,383,916,156	$ 26,354,159,736	$ 95,965,382	$ 4,168,995,276
29	$ 2,246,033,582	$ 575,678,520	$ 260,502,693	$ 1,409,852,369	$ 27,764,012,105	$ 88,876,260	$ 4,257,871,535
30	$ 2,282,165,078	$ 586,188,013	$ 260,502,693	$ 1,435,474,372	$ 29,199,486,477	$ 82,264,960	$ 4,340,136,495

Table A9 CSC partial-upgrading without pitch present value cash flow

Year	Operating Revenue (4)	Income Tax (4)	Yearly Capital Additional(5)	Yearly Cash Flow	Cumulative total cash flow	Present Value of yearly cash flow	Cumulative total PV of yearly cash flow
0	$ -	$ -	$ 7,270,285,699	$ (7,270,285,699)	$ (7,270,285,699)	$ (7,270,285,699)	$ (7,270,285,699)
1	$ 1,762,338,570	$ -	$ 260,502,693	$ 1,501,835,877	$ (5,768,449,822)	$ 1,390,588,775	$ (5,879,696,924)
2	$ 1,817,750,726	$ -	$ 260,502,693	$ 1,557,248,033	$ (4,211,201,789)	$ 1,335,089,192	$ (4,544,607,732)
3	$ 1,872,649,190	$ 177,425,896	$ 260,502,693	$ 1,434,720,602	$ (2,776,481,187)	$ 1,138,927,470	$ (3,405,680,262)
4	$ 1,927,033,962	$ 316,608,644	$ 260,502,693	$ 1,349,922,625	$ (1,426,558,562)	$ 992,233,428	$ (2,413,446,833)
5	$ 1,531,668,829	$ 243,624,111	$ 260,502,693	$ 1,027,542,024	$ (399,016,538)	$ 699,327,836	$ (1,714,118,997)
6	$ 1,566,588,324	$ 285,004,282	$ 260,502,693	$ 1,021,081,349	$ 622,064,811	$ 643,454,453	$ (1,070,664,545)
7	$ 1,600,773,376	$ 318,358,085	$ 260,502,693	$ 1,021,912,598	$ 1,643,977,410	$ 596,276,186	$ (474,388,359)
8	$ 1,634,223,985	$ 345,638,865	$ 260,502,693	$ 1,028,082,427	$ 2,672,059,837	$ 555,440,946	$ 81,052,587
9	$ 1,666,940,151	$ 368,311,630	$ 260,502,693	$ 1,038,125,828	$ 3,710,185,665	$ 519,321,373	$ 600,373,960
10	$ 1,698,921,874	$ 387,475,138	$ 260,502,693	$ 1,050,944,043	$ 4,761,129,707	$ 486,790,437	$ 1,087,164,397
11	$ 1,730,169,154	$ 403,953,455	$ 260,502,693	$ 1,065,713,005	$ 5,826,842,713	$ 457,066,041	$ 1,544,230,438
12	$ 1,760,681,990	$ 418,364,633	$ 260,502,693	$ 1,081,814,665	$ 6,908,657,377	$ 429,603,488	$ 1,973,833,926
13	$ 1,790,460,384	$ 431,172,208	$ 260,502,693	$ 1,098,785,483	$ 8,007,442,861	$ 404,021,142	$ 2,377,855,068
14	$ 1,819,504,335	$ 442,723,834	$ 260,502,693	$ 1,116,277,808	$ 9,123,720,668	$ 380,049,105	$ 2,757,904,173
15	$ 1,847,813,842	$ 453,280,252	$ 260,502,693	$ 1,134,030,897	$ 10,257,751,566	$ 357,493,834	$ 3,115,398,006
16	$ 1,875,388,907	$ 463,037,016	$ 260,502,693	$ 1,151,849,198	$ 11,409,600,764	$ 336,213,801	$ 3,451,611,807
17	$ 1,902,229,528	$ 472,140,792	$ 260,502,693	$ 1,169,586,042	$ 12,579,186,806	$ 316,102,793	$ 3,767,714,601
18	$ 1,928,335,706	$ 480,701,582	$ 260,502,693	$ 1,187,131,432	$ 13,766,318,238	$ 297,078,488	$ 4,064,793,089
19	$ 1,953,707,441	$ 488,801,883	$ 260,502,693	$ 1,204,402,865	$ 14,970,721,103	$ 279,074,674	$ 4,343,867,763
20	$ 1,980,374,756	$ 497,092,278	$ 260,502,693	$ 1,222,779,785	$ 16,193,500,888	$ 262,345,211	$ 4,606,212,974

21	$ 2,020,451,318	$ 509,132,136	$ 260,502,693	$ 1,250,816,489	$ 17,444,317,377	$ 248,481,885	$ 4,854,694,858
22	$ 2,060,527,880	$ 521,067,580	$ 260,502,693	$ 1,278,957,607	$ 18,723,274,984	$ 235,252,111	$ 5,089,946,969
23	$ 2,100,604,442	$ 532,924,714	$ 260,502,693	$ 1,307,177,035	$ 20,030,452,019	$ 222,632,228	$ 5,312,579,197
24	$ 2,140,681,004	$ 544,723,115	$ 260,502,693	$ 1,335,455,195	$ 21,365,907,214	$ 210,600,399	$ 5,523,179,597
25	$ 2,180,757,566	$ 556,477,467	$ 260,502,693	$ 1,363,777,406	$ 22,729,684,620	$ 199,135,920	$ 5,722,315,516
26	$ 2,220,834,128	$ 568,198,782	$ 260,502,693	$ 1,392,132,653	$ 24,121,817,273	$ 188,218,790	$ 5,910,534,306
27	$ 2,260,910,690	$ 579,895,318	$ 260,502,693	$ 1,420,512,679	$ 25,542,329,952	$ 177,829,463	$ 6,088,363,769
28	$ 2,300,987,252	$ 591,573,271	$ 260,502,693	$ 1,448,911,287	$ 26,991,241,239	$ 167,948,698	$ 6,256,312,467
29	$ 2,341,063,814	$ 603,237,287	$ 260,502,693	$ 1,477,323,834	$ 28,468,565,073	$ 158,557,502	$ 6,414,869,969
30	$ 2,380,715,078	$ 614,767,513	$ 260,502,693	$ 1,505,444,872	$ 29,974,009,945	$ 149,607,096	$ 6,564,477,065

Table A10 Coking full-upgrading present value cash flow

Year	Operating Revenue (4)	Income Tax (4)	Yearly Capital Additional(5)	Yearly Cash Flow	Cumulative total cash flow	Present Value of yearly cash flow	Cumulative total PV of yearly cash flow
0	$ -	$ -	$ 11,218,179,559	$ (11,218,179,559)	$ (11,218,179,559)	$ (11,218,179,559)	$ (11,218,179,559)
1	$ 1,805,335,496	$ -	$ 295,135,999	$ 1,510,199,497	$ (9,707,980,062)	$ 1,398,332,868	$ (9,819,846,691)
2	$ 1,877,600,904	$ -	$ 295,135,999	$ 1,582,464,905	$ (8,125,515,157)	$ 1,356,708,595	$ (8,463,138,097)
3	$ 1,949,299,992	$ -	$ 295,135,999	$ 1,654,163,993	$ (6,471,351,164)	$ 1,313,128,710	$ (7,150,009,387)
4	$ 2,020,432,762	$ -	$ 295,135,999	$ 1,725,296,763	$ (4,746,054,401)	$ 1,268,144,626	$ (5,881,864,761)
5	$ 2,090,999,213	$ 48,434,505	$ 295,135,999	$ 1,747,428,709	$ (2,998,625,692)	$ 1,189,270,617	$ (4,692,594,144)
6	$ 2,160,999,345	$ 389,993,643	$ 295,135,999	$ 1,475,869,703	$ (1,522,755,989)	$ 930,048,260	$ (3,762,545,884)
7	$ 2,230,433,158	$ 447,906,130	$ 295,135,999	$ 1,487,391,028	$ (35,364,961)	$ 867,878,379	$ (2,894,667,505)
8	$ 1,720,611,646	$ 328,390,403	$ 295,135,999	$ 1,097,085,243	$ 1,061,720,283	$ 592,721,021	$ (2,301,946,484)
9	$ 1,760,773,007	$ 361,286,582	$ 295,135,999	$ 1,104,350,427	$ 2,166,070,709	$ 552,450,160	$ (1,749,496,324)
10	$ 1,799,870,794	$ 388,561,978	$ 295,135,999	$ 1,116,172,818	$ 3,282,243,527	$ 517,003,981	$ (1,232,492,343)
11	$ 1,837,905,007	$ 411,544,677	$ 295,135,999	$ 1,131,224,330	$ 4,413,467,857	$ 485,162,725	$ (747,329,618)
12	$ 1,874,875,644	$ 431,230,746	$ 295,135,999	$ 1,148,508,899	$ 5,561,976,756	$ 456,088,686	$ (291,240,932)
13	$ 1,910,782,707	$ 448,367,232	$ 295,135,999	$ 1,167,279,476	$ 6,729,256,232	$ 429,206,241	$ 137,965,309
14	$ 1,945,626,196	$ 463,514,422	$ 295,135,999	$ 1,186,975,775	$ 7,916,232,007	$ 404,119,008	$ 542,084,317
15	$ 1,979,406,110	$ 477,092,531	$ 295,135,999	$ 1,207,177,580	$ 9,123,409,586	$ 380,552,718	$ 922,637,035
16	$ 2,025,087,280	$ 493,176,521	$ 295,135,999	$ 1,236,774,761	$ 10,360,184,347	$ 361,002,763	$ 1,283,639,798
17	$ 2,075,794,540	$ 510,008,964	$ 295,135,999	$ 1,270,649,577	$ 11,630,833,924	$ 343,417,129	$ 1,627,056,927
18	$ 2,126,501,800	$ 526,309,572	$ 295,135,999	$ 1,305,056,229	$ 12,935,890,153	$ 326,589,054	$ 1,953,645,982
19	$ 2,177,209,060	$ 542,211,305	$ 295,135,999	$ 1,339,861,756	$ 14,275,751,909	$ 310,462,133	$ 2,264,108,115
20	$ 2,227,916,320	$ 557,813,881	$ 295,135,999	$ 1,374,966,440	$ 15,650,718,349	$ 294,996,585	$ 2,559,104,699
21	$ 2,278,623,580	$ 573,192,090	$ 295,135,999	$ 1,410,295,491	$ 17,061,013,840	$ 280,163,305	$ 2,839,268,005
22	$ 2,329,330,840	$ 588,402,022	$ 295,135,999	$ 1,445,792,819	$ 18,506,806,659	$ 265,939,864	$ 3,105,207,869

23	$ 2,380,038,100	$ 603,485,748	$ 295,135,999	$ 1,481,416,353	$ 19,988,223,012	$ 252,307,847	$ 3,357,515,716
24	$ 2,430,745,360	$ 618,474,819	$ 295,135,999	$ 1,517,134,542	$ 21,505,357,555	$ 239,251,112	$ 3,596,766,828
25	$ 2,481,452,620	$ 633,392,898	$ 295,135,999	$ 1,552,923,723	$ 23,058,281,278	$ 226,754,669	$ 3,823,521,497
26	$ 2,532,159,880	$ 648,257,734	$ 295,135,999	$ 1,588,766,147	$ 24,647,047,425	$ 214,803,985	$ 4,038,325,482
27	$ 2,582,867,140	$ 663,082,637	$ 295,135,999	$ 1,624,648,504	$ 26,271,695,929	$ 203,384,577	$ 4,241,710,059
28	$ 2,633,574,400	$ 677,877,591	$ 295,135,999	$ 1,660,560,810	$ 27,932,256,739	$ 192,481,782	$ 4,434,191,841
29	$ 2,684,281,660	$ 692,650,083	$ 295,135,999	$ 1,696,495,578	$ 29,628,752,317	$ 182,080,662	$ 4,616,272,503
30	$ 2,772,293,380	$ 718,224,021	$ 295,135,999	$ 1,758,933,360	$ 31,387,685,677	$ 174,798,105	$ 4,791,070,608

Appendix H. Economic Analysis Framework – Annual Production (Schedule 2)

Table A11 Assumed crude price forecasts

Year	Dilbit Price	Partial-upgrading w pitch price	Partial-upgrading no pitch price	Full Upgraded Price	Naphtha Price
0					
1	$ 75	$ 75	$ 75	$ 81	$ 82
2	$ 77	$ 77	$ 77	$ 84	$ 86
3	$ 80	$ 80	$ 80	$ 86	$ 91
4	$ 82	$ 82	$ 82	$ 89	$ 95
5	$ 85	$ 85	$ 85	$ 92	$ 100
6	$ 87	$ 87	$ 87	$ 95	$ 104
7	$ 89	$ 89	$ 89	$ 97	$ 108
8	$ 92	$ 92	$ 92	$ 100	$ 113
9	$ 94	$ 94	$ 94	$ 103	$ 117
10	$ 96	$ 96	$ 96	$ 106	$ 122
11	$ 99	$ 99	$ 99	$ 108	$ 126
12	$ 101	$ 101	$ 101	$ 111	$ 131
13	$ 104	$ 104	$ 104	$ 114	$ 135
14	$ 106	$ 106	$ 106	$ 116	$ 139
15	$ 108	$ 108	$ 108	$ 119	$ 144
16	$ 111	$ 111	$ 111	$ 122	$ 148
17	$ 113	$ 113	$ 113	$ 125	$ 153
18	$ 115	$ 115	$ 115	$ 127	$ 157
19	$ 118	$ 118	$ 118	$ 130	$ 161
20	$ 120	$ 120	$ 120	$ 133	$ 166
21	$ 123	$ 123	$ 123	$ 135	$ 170
22	$ 125	$ 125	$ 125	$ 138	$ 175
23	$ 127	$ 127	$ 127	$ 141	$ 179
24	$ 130	$ 130	$ 130	$ 144	$ 184
25	$ 132	$ 132	$ 132	$ 146	$ 188
26	$ 135	$ 135	$ 135	$ 149	$ 192
27	$ 137	$ 137	$ 137	$ 152	$ 197
28	$ 139	$ 139	$ 139	$ 155	$ 201
29	$ 142	$ 142	$ 142	$ 157	$ 206
30	$ 144	$ 144	$ 144	$ 162	$ 210

Table A12 Annual production revenue and diluent costs

	Dilution			Partial-upgrading with Pitch			Partial-upgrading without Pitch			Coking Full Upgrade	
	Revenue	Diluent cost		Revenue	Diluent cost		Revenue	Diluent cost		Revenue	Diluent cost
bpd	143,000	43,000		111,000	22,000		98,000	13,000		85,000	0
	$ 3,914,625,000	$ 1,286,990,000		$ 3,038,625,000	$ 658,460,000		$ 2,764,875,000	$ 389,090,000		$ 2,513,025,000	$ -
	$ 4,038,849,100	$ 1,356,267,730		$ 3,135,050,700	$ 693,904,420		$ 2,852,613,700	$ 410,034,430		$ 2,597,537,100	$ -
	$ 4,163,073,200	$ 1,425,545,460		$ 3,231,476,400	$ 729,348,840		$ 2,940,352,400	$ 430,978,860		$ 2,682,049,200	$ -
	$ 4,287,297,300	$ 1,494,823,190		$ 3,327,902,100	$ 764,793,260		$ 3,028,091,100	$ 451,923,290		$ 2,766,561,300	$ -
	$ 4,411,521,400	$ 1,564,100,920		$ 3,424,327,800	$ 800,237,680		$ 3,115,829,800	$ 472,867,720		$ 2,851,073,400	$ -
	$ 4,535,745,500	$ 1,633,378,650		$ 3,520,753,500	$ 835,682,100		$ 3,203,568,500	$ 493,812,150		$ 2,935,585,500	$ -
	$ 4,659,969,600	$ 1,702,656,380		$ 3,617,179,200	$ 871,126,520		$ 3,291,307,200	$ 514,756,580		$ 3,020,097,600	$ -
	$ 4,784,193,700	$ 1,771,934,110		$ 3,713,604,900	$ 906,570,940		$ 3,379,045,900	$ 535,701,010		$ 3,104,609,700	$ -
	$ 4,908,417,800	$ 1,841,211,840		$ 3,810,030,600	$ 942,015,360		$ 3,466,784,600	$ 556,645,440		$ 3,189,121,800	$ -
	$ 5,032,641,900	$ 1,910,489,570		$ 3,906,456,300	$ 977,459,780		$ 3,554,523,300	$ 577,589,870		$ 3,273,633,900	$ -
	$ 5,156,866,000	$ 1,979,767,300		$ 4,002,882,000	$ 1,012,904,200		$ 3,642,262,000	$ 598,534,300		$ 3,358,146,000	$ -
	$ 5,281,090,100	$ 2,049,045,030		$ 4,099,307,700	$ 1,048,348,620		$ 3,730,000,700	$ 619,478,730		$ 3,442,658,100	$ -
	$ 5,405,314,200	$ 2,118,322,760		$ 4,195,733,400	$ 1,083,793,040		$ 3,817,739,400	$ 640,423,160		$ 3,527,170,200	$ -
	$ 5,529,538,300	$ 2,187,600,490		$ 4,292,159,100	$ 1,119,237,460		$ 3,905,478,100	$ 661,367,590		$ 3,611,682,300	$ -
	$ 5,653,762,400	$ 2,256,878,220		$ 4,388,584,800	$ 1,154,681,880		$ 3,993,216,800	$ 682,312,020		$ 3,696,194,400	$ -
	$ 5,777,986,500	$ 2,326,155,950		$ 4,485,010,500	$ 1,190,126,300		$ 4,080,955,500	$ 703,256,450		$ 3,780,706,500	$ -
	$ 5,902,210,600	$ 2,395,433,680		$ 4,581,436,200	$ 1,225,570,720		$ 4,168,694,200	$ 724,200,880		$ 3,865,218,600	$ -

	$ 6,026,434,700	$ 2,464,711,410		$ 4,677,861,900	$ 1,261,015,140		$ 4,256,432,900	$ 745,145,310		$ 3,949,730,700	$ -
	$ 6,150,658,800	$ 2,533,989,140		$ 4,774,287,600	$ 1,296,459,560		$ 4,344,171,600	$ 766,089,740		$ 4,034,242,800	$ -
	$ 6,274,882,900	$ 2,603,266,870		$ 4,870,713,300	$ 1,331,903,980		$ 4,431,910,300	$ 787,034,170		$ 4,118,754,900	$ -
	$ 6,399,107,000	$ 2,672,544,600		$ 4,967,139,000	$ 1,367,348,400		$ 4,519,649,000	$ 807,978,600		$ 4,203,267,000	$ -
	$ 6,523,331,100	$ 2,741,822,330		$ 5,063,564,700	$ 1,402,792,820		$ 4,607,387,700	$ 828,923,030		$ 4,287,779,100	$ -
	$ 6,647,555,200	$ 2,811,100,060		$ 5,159,990,400	$ 1,438,237,240		$ 4,695,126,400	$ 849,867,460		$ 4,372,291,200	$ -
	$ 6,771,779,300	$ 2,880,377,790		$ 5,256,416,100	$ 1,473,681,660		$ 4,782,865,100	$ 870,811,890		$ 4,456,803,300	$ -
	$ 6,896,003,400	$ 2,949,655,520		$ 5,352,841,800	$ 1,509,126,080		$ 4,870,603,800	$ 891,756,320		$ 4,541,315,400	$ -
	$ 7,020,227,500	$ 3,018,933,250		$ 5,449,267,500	$ 1,544,570,500		$ 4,958,342,500	$ 912,700,750		$ 4,625,827,500	$ -
	$ 7,144,451,600	$ 3,088,210,980		$ 5,545,693,200	$ 1,580,014,920		$ 5,046,081,200	$ 933,645,180		$ 4,710,339,600	$ -
	$ 7,268,675,700	$ 3,157,488,710		$ 5,642,118,900	$ 1,615,459,340		$ 5,133,819,900	$ 954,589,610		$ 4,794,851,700	$ -
	$ 7,392,899,800	$ 3,226,766,440		$ 5,738,544,600	$ 1,650,903,760		$ 5,221,558,600	$ 975,534,040		$ 4,879,363,800	$ -
	$ 7,516,080,000	$ 3,295,950,000		$ 5,834,160,000	$ 1,686,300,000		$ 5,308,560,000	$ 996,450,000		$ 5,026,050,000	$ -

Appendix I. Economic Analysis Framework – Royalties Calculation (Schedule 3)

Table A13 Dilution royalties calculation

DILUTION										Payout rate - 5.5% rate of return on cumulative capital cost allowances and operational expenses					
Year	Revenue (2)	Diluent (2)	Extration O&M	Upgrader O&I	Additions Ext Ca	Additions Up/Dil	Carbon Tax (4)	Royalties R	Royalties R	Royalties from yea	Royalties from yea	Royalties from yea	Operating Revenu	Cumulative Opera	Royalty Payout
										(ON GROSS REVEN	(ON NET REVENUE)				(5.5% OF CUMULAT
0					$5,270,285,699	$ 3,764,490							$ (5,274,050,189)	$ (5,274,050,189)	$ 290,072,760
1	$ 3,914,625,000	$ 1,286,990,000	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	3%	30%	$ 135,250,294	$ 595,481,141	$ 135,250,294	$ 1,874,812,628	$ (3,399,237,561)	$ 394,823,675
2	$ 4,038,849,100	$ 1,356,267,730	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	4%	30%	$ 151,365,563	$ 623,112,011	$ 151,365,563	$ 1,913,643,729	$ (1,485,593,832)	$ 503,384,864
3	$ 4,163,073,200	$ 1,425,545,460	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	4%	31%	$ 168,208,140	$ 651,347,049	$ 168,208,140	$ 1,951,747,522	$ 466,153,690	$ 615,756,329
4	$ 4,287,297,300	$ 1,494,823,190	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	4%	31%	$ 185,778,024	$ 680,186,256	$ 680,186,256	$ 1,989,124,008	$ 2,455,277,698	$ 731,938,068
5	$ 4,411,521,400	$ 1,564,100,920	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	5%	32%	$ 204,075,215	$ 709,629,631	$ 709,629,631	$ 2,025,773,186	$ 4,481,050,884	$ 851,930,083
6	$ 4,535,745,500	$ 1,633,378,650	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	5%	32%	$ 223,099,714	$ 739,677,175	$ 739,677,175	$ 2,061,695,058	$ 6,542,745,942	$ 975,732,373
7	$ 4,659,969,600	$ 1,702,656,380	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	5%	33%	$ 242,851,520	$ 770,328,886	$ 770,328,886	$ 2,096,889,622	$ 8,639,635,564	$ 1,103,344,939
8	$ 4,784,193,700	$ 1,771,934,110	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	6%	33%	$ 263,330,633	$ 801,584,766	$ 801,584,766	$ 2,131,356,879	$ 10,770,992,443	$ 1,234,767,779
9	$ 4,908,417,800	$ 1,841,211,840	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	6%	34%	$ 284,537,053	$ 833,444,815	$ 833,444,815	$ 2,165,096,829	$ 12,936,089,272	$ 1,370,000,894
10	$ 5,032,641,900	$ 1,910,489,570	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	6%	35%	$ 306,470,781	$ 865,909,031	$ 865,909,031	$ 2,198,109,471	$ 15,134,198,743	$ 1,509,044,285
11	$ 5,156,866,000	$ 1,979,767,300	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	6%	35%	$ 329,131,816	$ 898,977,416	$ 898,977,416	$ 2,230,394,806	$ 17,364,593,549	$ 1,651,897,951
12	$ 5,281,090,100	$ 2,049,045,030	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	7%	36%	$ 352,520,158	$ 932,649,970	$ 932,649,970	$ 2,261,952,834	$ 19,626,546,383	$ 1,798,561,892
13	$ 5,405,314,200	$ 2,118,322,760	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	7%	36%	$ 376,635,807	$ 966,926,691	$ 966,926,691	$ 2,292,783,555	$ 21,919,329,938	$ 1,949,036,108
14	$ 5,529,538,300	$ 2,187,600,490	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	7%	37%	$ 401,478,764	$ 1,001,807,581	$ 1,001,807,581	$ 2,322,886,968	$ 24,242,216,906	$ 2,103,320,599
15	$ 5,653,762,400	$ 2,256,878,220	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	8%	37%	$ 427,049,028	$ 1,037,292,639	$ 1,037,292,639	$ 2,352,263,074	$ 26,594,479,980	$ 2,261,415,366
16	$ 5,777,986,500	$ 2,326,155,950	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	8%	38%	$ 453,346,599	$ 1,073,381,866	$ 1,073,381,866	$ 2,380,911,873	$ 28,975,391,853	$ 2,423,320,407
17	$ 5,902,210,600	$ 2,395,433,680	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	8%	38%	$ 480,371,477	$ 1,110,075,260	$ 1,110,075,260	$ 2,408,833,365	$ 31,384,225,218	$ 2,589,035,724
18	$ 6,026,434,700	$ 2,464,711,410	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	8%	39%	$ 508,123,663	$ 1,147,372,824	$ 1,147,372,824	$ 2,436,027,549	$ 33,820,252,767	$ 2,758,561,316
19	$ 6,150,658,800	$ 2,533,989,140	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 536,603,156	$ 1,185,274,555	$ 1,185,274,555	$ 2,462,494,426	$ 36,282,747,193	$ 2,931,897,183
20	$ 6,274,882,900	$ 2,603,266,870	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 564,739,461	$ 1,221,617,581	$ 1,221,617,581	$ 2,489,304,491	$ 38,772,051,684	$ 3,109,043,325
21	$ 6,399,107,000	$ 2,672,544,600	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 575,919,630	$ 1,243,596,129	$ 1,243,596,129	$ 2,533,070,692	$ 41,305,122,375	$ 3,289,999,742
22	$ 6,523,331,100	$ 2,741,822,330	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 587,099,799	$ 1,265,574,677	$ 1,265,574,677	$ 2,576,836,893	$ 43,881,959,268	$ 3,474,766,435
23	$ 6,647,555,200	$ 2,811,100,060	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 598,279,968	$ 1,287,553,225	$ 1,287,553,225	$ 2,620,603,094	$ 46,502,562,362	$ 3,663,343,402
24	$ 6,771,779,300	$ 2,880,377,790	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 609,460,137	$ 1,309,531,773	$ 1,309,531,773	$ 2,664,369,295	$ 49,166,931,657	$ 3,855,730,645
25	$ 6,896,003,400	$ 2,949,655,520	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 620,640,306	$ 1,331,510,321	$ 1,331,510,321	$ 2,708,135,496	$ 51,875,067,153	$ 4,051,928,163
26	$ 7,020,227,500	$ 3,018,933,250	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 631,820,475	$ 1,353,488,869	$ 1,353,488,869	$ 2,751,901,697	$ 54,626,968,849	$ 4,251,935,956
27	$ 7,144,451,600	$ 3,088,210,980	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 643,000,644	$ 1,375,467,417	$ 1,375,467,417	$ 2,795,667,898	$ 57,422,636,747	$ 4,455,754,024
28	$ 7,268,675,700	$ 3,157,488,710	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 654,180,813	$ 1,397,445,965	$ 1,397,445,965	$ 2,839,434,099	$ 60,262,070,846	$ 4,663,382,367
29	$ 7,392,899,800	$ 3,226,766,440	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 665,360,982	$ 1,419,424,513	$ 1,419,424,513	$ 2,883,200,300	$ 63,145,271,146	$ 4,874,820,986
30	$ 7,516,080,000	$ 3,295,950,000	$368,919,999	$ 195,753	$ 248,456,326	$ -	$ -	9%	40%	$ 676,447,200	$ 1,441,023,169	$ 1,441,023,169	$ 2,926,110,722	$ 66,071,381,868	$ 5,090,064,700

Table A14 CSC partial-upgrading with pitch royalties calculation

Partial w pitch															
Year	Revenue (2)	Diluent (2)	Extration O&M e	Upgrader O&M	Additions Ext Ca	Additions Up/Dil (	Carbon Tax (4)	Royalties I	Royalties I	Royalties from y	Royalties from yea	Royalties from y	Operating Revenu	Cumulative Operat	Royalty Payout
EXPENSES)															
0	$ -	$ -	$ -	$ -	$5,270,285,699	$ 2,000,000,000							$ (7,270,285,699)	$ (7,270,285,699)	$ 399,865,713
1	$ 3,038,625,000	$ 658,460,000	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	3%	30%	$ 104,984,494	$ 474,516,159	$ 104,984,494	$ 1,496,757,814	$ (5,773,527,885)	$ 478,894,261
2	$ 3,135,050,700	$ 693,904,420	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	30%	$ 117,493,549	$ 501,723,185	$ 117,493,549	$ 1,545,230,039	$ (4,228,297,846)	$ 559,872,253
3	$ 3,231,476,400	$ 729,348,840	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	31%	$ 130,567,158	$ 529,600,736	$ 130,567,158	$ 1,593,137,710	$ (2,635,160,135)	$ 642,799,687
4	$ 3,327,902,100	$ 764,793,260	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	31%	$ 144,205,319	$ 558,148,814	$ 144,205,319	$ 1,640,480,829	$ (994,679,307)	$ 727,676,564
5	$ 3,424,327,800	$ 800,237,680	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	32%	$ 158,408,034	$ 587,367,417	$ 158,408,034	$ 1,687,259,394	$ 692,580,087	$ 814,502,885
6	$ 3,520,753,500	$ 835,682,100	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	32%	$ 173,175,302	$ 617,256,546	$ 617,256,546	$ 1,733,473,406	$ 2,426,053,492	$ 903,278,648
7	$ 3,617,179,200	$ 871,126,520	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	33%	$ 188,507,124	$ 647,816,201	$ 647,816,201	$ 1,779,122,864	$ 4,205,176,357	$ 994,003,855
8	$ 3,713,604,900	$ 906,570,940	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	33%	$ 204,403,498	$ 679,046,381	$ 679,046,381	$ 1,824,207,770	$ 6,029,384,127	$ 1,086,678,505
9	$ 3,810,030,600	$ 942,015,360	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	34%	$ 220,864,426	$ 710,947,088	$ 710,947,088	$ 1,868,728,122	$ 7,898,112,249	$ 1,181,302,598
10	$ 3,906,456,300	$ 977,459,780	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	35%	$ 237,889,907	$ 743,518,320	$ 743,518,320	$ 1,912,683,921	$ 9,810,796,170	$ 1,277,876,134
11	$ 4,002,882,000	$1,012,904,200	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	35%	$ 255,479,941	$ 776,760,077	$ 776,760,077	$ 1,956,075,167	$ 11,766,871,337	$ 1,376,399,113
12	$ 4,099,307,700	$1,048,348,620	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	36%	$ 273,634,528	$ 810,672,361	$ 810,672,361	$ 1,998,901,860	$ 13,765,773,197	$ 1,476,871,535
13	$ 4,195,733,400	$1,083,793,040	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	36%	$ 292,353,668	$ 845,255,170	$ 845,255,170	$ 2,041,164,000	$ 15,806,937,197	$ 1,579,293,400
14	$ 4,292,159,100	$1,119,237,460	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	37%	$ 311,637,362	$ 880,508,505	$ 880,508,505	$ 2,082,861,586	$ 17,889,798,783	$ 1,683,664,708
15	$ 4,388,584,800	$1,154,681,880	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	37%	$ 331,485,609	$ 916,432,366	$ 916,432,366	$ 2,123,994,619	$ 20,013,793,402	$ 1,789,985,460
16	$ 4,485,010,500	$1,190,126,300	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	38%	$ 351,898,409	$ 953,026,753	$ 953,026,753	$ 2,164,563,099	$ 22,178,356,501	$ 1,898,255,654
17	$ 4,581,436,200	$1,225,570,720	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	38%	$ 372,875,762	$ 990,291,665	$ 990,291,665	$ 2,204,567,026	$ 24,382,923,527	$ 2,008,475,292
18	$ 4,677,861,900	$1,261,015,140	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	39%	$ 394,417,668	$ 1,028,227,103	$1,028,227,103	$ 2,244,006,400	$ 26,626,929,926	$ 2,120,644,373
19	$ 4,774,287,600	$1,296,459,560	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 416,524,128	$ 1,066,833,067	$1,066,833,067	$ 2,282,881,220	$ 28,909,811,146	$ 2,234,762,897
20	$ 4,870,713,300	$1,331,903,980	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 438,364,197	$ 1,104,154,651	$1,104,154,651	$ 2,322,022,431	$ 31,231,833,577	$ 2,350,830,864
21	$ 4,967,139,000	$1,367,348,400	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 447,042,510	$ 1,128,547,163	$1,128,547,163	$ 2,374,325,398	$ 33,606,158,975	$ 2,468,848,274
22	$ 5,063,564,700	$1,402,792,820	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 455,720,823	$ 1,152,939,675	$1,152,939,675	$ 2,426,628,365	$ 36,032,787,340	$ 2,588,815,127
23	$ 5,159,990,400	$1,438,237,240	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 464,399,136	$ 1,177,332,187	$1,177,332,187	$ 2,478,931,332	$ 38,511,718,672	$ 2,710,731,423
24	$ 5,256,416,100	$1,473,681,660	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 473,077,449	$ 1,201,724,699	$1,201,724,699	$ 2,531,234,299	$ 41,042,952,971	$ 2,834,597,163
25	$ 5,352,841,800	$1,509,126,080	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 481,755,762	$ 1,226,117,211	$1,226,117,211	$ 2,583,537,266	$ 43,626,490,237	$ 2,960,412,345
26	$ 5,449,267,500	$1,544,570,500	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 490,434,075	$ 1,250,509,723	$1,250,509,723	$ 2,635,840,233	$ 46,262,330,470	$ 3,088,176,971
27	$ 5,545,693,200	$1,580,014,920	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 499,112,388	$ 1,274,902,235	$1,274,902,235	$ 2,688,143,200	$ 48,950,473,670	$ 3,217,891,039
28	$ 5,642,118,900	$1,615,459,340	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 507,790,701	$ 1,299,294,747	$1,299,294,747	$ 2,740,446,167	$ 51,690,919,837	$ 3,349,554,551
29	$ 5,738,544,600	$1,650,903,760	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 516,469,014	$ 1,323,687,259	$1,323,687,259	$ 2,792,749,134	$ 54,483,668,971	$ 3,483,167,506
30	$ 5,834,160,000	$1,686,300,000	$ 368,919,999	$149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 525,074,400	$ 1,347,774,923	$1,347,774,923	$ 2,844,362,908	$ 57,328,031,879	$ 3,618,727,254

Table A15 CSC partial-upgrading without pitch royalties calculation

Partial wo ptch															
Year	Revenue (2)	Diluent (2)	Extration O&M e	Upgrader O&M	Additions Ext Ca	Additions Up/Dil C	Carbon Tax (4)	Royalties	Royalties	Royalties from y	Royalties from yea	Royalties from year	Operating Revenu	Cumulative Operat	Royalty Payout
0	$ -	$ -	$ -	$ -	$5,270,285,699	$ 2,000,000,000							$ (7,270,285,699)	$ (7,270,285,699)	$ 399,865,713
1	$ 2,764,875,000	$ 389,090,000	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	3%	30%	$ 95,526,431	$ 473,218,584	$ 95,526,431	$ 1,501,835,877	$ (5,768,449,822)	$ 464,078,911
2	$ 2,852,613,700	$ 410,034,430	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	30%	$ 106,908,545	$ 502,155,586	$ 106,908,545	$ 1,557,248,033	$ (4,211,201,789)	$ 529,444,053
3	$ 2,940,352,400	$ 430,978,860	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	31%	$ 118,804,351	$ 531,827,032	$ 118,804,351	$ 1,612,146,497	$ (2,599,055,291)	$ 595,961,139
4	$ 3,028,091,100	$ 451,923,290	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	4%	31%	$ 131,213,849	$ 562,232,921	$ 131,213,849	$ 1,666,531,269	$ (932,524,023)	$ 663,630,168
5	$ 3,115,829,800	$ 472,867,720	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	32%	$ 144,137,040	$ 593,373,252	$ 593,373,252	$ 1,720,402,348	$ 787,878,325	$ 732,451,140
6	$ 3,203,568,500	$ 493,812,150	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	32%	$ 157,573,924	$ 625,248,027	$ 625,248,027	$ 1,773,759,734	$ 2,561,638,059	$ 802,424,057
7	$ 3,291,307,200	$ 514,756,580	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	5%	33%	$ 171,524,500	$ 657,857,245	$ 657,857,245	$ 1,826,603,428	$ 4,388,241,487	$ 873,548,917
8	$ 3,379,045,900	$ 535,701,010	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	33%	$ 185,988,769	$ 691,200,906	$ 691,200,906	$ 1,878,933,429	$ 6,267,174,917	$ 945,825,720
9	$ 3,466,784,600	$ 556,645,440	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	34%	$ 200,966,730	$ 725,279,010	$ 725,279,010	$ 1,930,749,738	$ 8,197,924,655	$1,019,254,467
10	$ 3,554,523,300	$ 577,589,870	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	35%	$ 216,458,384	$ 760,091,557	$ 760,091,557	$ 1,982,052,354	$ 10,179,977,009	$1,093,835,158
11	$ 3,642,262,000	$ 598,534,300	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	6%	35%	$ 232,463,730	$ 795,638,547	$ 795,638,547	$ 2,032,841,278	$ 12,212,818,287	$1,169,567,793
12	$ 3,730,000,700	$ 619,478,730	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	36%	$ 248,982,769	$ 831,919,981	$ 831,919,981	$ 2,083,116,509	$ 14,295,934,796	$1,246,452,371
13	$ 3,817,739,400	$ 640,423,160	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	36%	$ 266,015,500	$ 868,935,857	$ 868,935,857	$ 2,132,878,048	$ 16,428,812,844	$1,324,488,893
14	$ 3,905,478,100	$ 661,367,590	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	7%	37%	$ 283,561,924	$ 906,686,176	$ 906,686,176	$ 2,182,125,894	$ 18,610,938,738	$1,403,677,358
15	$ 3,993,216,800	$ 682,312,020	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	37%	$ 301,622,040	$ 945,170,939	$ 945,170,939	$ 2,230,860,047	$ 20,841,798,786	$1,484,017,768
16	$ 4,080,955,500	$ 703,256,450	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	38%	$ 320,195,849	$ 984,390,144	$ 984,390,144	$ 2,279,080,508	$ 23,120,879,294	$1,565,510,120
17	$ 4,168,694,200	$ 724,200,880	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	38%	$ 339,283,351	$ 1,024,343,793	$ 1,024,343,793	$ 2,326,787,277	$ 25,447,666,571	$1,648,154,417
18	$ 4,256,432,900	$ 745,145,310	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	8%	39%	$ 358,884,545	$ 1,065,031,885	$ 1,065,031,885	$ 2,373,980,353	$ 27,821,646,924	$1,731,950,657
19	$ 4,344,171,600	$ 766,089,740	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 378,999,432	$ 1,106,454,420	$ 1,106,454,420	$ 2,420,659,736	$ 30,242,306,660	$1,816,898,841
20	$ 4,431,910,300	$ 787,034,170	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 398,871,927	$ 1,146,581,375	$ 1,146,581,375	$ 2,467,581,511	$ 32,709,888,171	$1,902,998,968
21	$ 4,519,649,000	$ 807,978,600	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 406,768,410	$ 1,173,299,083	$ 1,173,299,083	$ 2,526,479,298	$ 35,236,367,469	$1,990,251,039
22	$ 4,607,387,700	$ 828,923,030	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 414,664,893	$ 1,200,016,791	$ 1,200,016,791	$ 2,585,377,085	$ 37,821,744,554	$2,078,655,054
23	$ 4,695,126,400	$ 849,867,460	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 422,561,376	$ 1,226,734,499	$ 1,226,734,499	$ 2,644,274,872	$ 40,466,019,426	$2,168,211,012
24	$ 4,782,865,100	$ 870,811,890	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 430,457,859	$ 1,253,452,207	$ 1,253,452,207	$ 2,703,172,659	$ 43,169,192,085	$2,258,918,914
25	$ 4,870,603,800	$ 891,756,320	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 438,354,342	$ 1,280,169,915	$ 1,280,169,915	$ 2,762,070,446	$ 45,931,262,531	$2,350,778,760
26	$ 4,958,342,500	$ 912,700,750	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 446,250,825	$ 1,306,887,623	$ 1,306,887,623	$ 2,820,968,233	$ 48,752,230,764	$2,443,790,549
27	$ 5,046,081,200	$ 933,645,180	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 454,147,308	$ 1,333,605,331	$ 1,333,605,331	$ 2,879,866,020	$ 51,632,096,784	$2,537,954,282
28	$ 5,133,819,900	$ 954,589,610	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 462,043,791	$ 1,360,323,039	$ 1,360,323,039	$ 2,938,763,807	$ 54,570,860,591	$2,633,269,959
29	$ 5,221,558,600	$ 975,534,040	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 469,940,274	$ 1,387,040,747	$ 1,387,040,747	$ 2,997,661,594	$ 57,568,522,185	$2,729,737,579
30	$ 5,308,560,000	$ 996,450,000	$ 368,919,999	$ 149,000,000	$ 248,456,326	$ 12,046,367	$ -	9%	40%	$ 477,770,400	$ 1,413,474,923	$ 1,413,474,923	$ 3,055,916,908	$ 60,624,439,093	$2,827,355,577

Table A16 Coking full-upgrading with pitch royalties calculation

coking full															
Year	Revenue (2)		Extration O&M e	Upgrader O&M	Additions Ext Cap	Additions Up/Dil	Carbon Tax (4)	Royalties I	Royalties I	Royalties from y	Royalties from yea	Royalties from yea	Operating Revenue (I	Cumulative Operat	Royalty Payout
0					$ 5,270,285,699	$5,947,893,860							$ (11,218,179,559)	$ (11,218,179,559)	$ 616,999,876
1	2513025000	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	4%	31%	$ 105,371,138	$ 501,004,610	$ 105,371,138	$ 1,510,199,497	$ (9,707,980,062)	$ 666,359,866
2	2597537100	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	5%	32%	$ 117,617,831	$ 537,910,326	$ 117,617,831	$ 1,582,464,905	$ (8,125,515,157)	$ 715,719,856
3	2682049200	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	5%	32%	$ 130,430,842	$ 575,879,616	$ 130,430,842	$ 1,654,163,993	$ (6,471,351,164)	$ 765,079,846
4	2766561300	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	5%	33%	$ 143,810,172	$ 614,912,481	$ 143,810,172	$ 1,725,296,763	$ (4,746,054,401)	$ 814,439,836
5	2851073400	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	6%	34%	$ 157,755,821	$ 655,008,921	$ 157,755,821	$ 1,795,863,214	$ (2,950,191,187)	$ 863,799,826
6	2935585500	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	6%	34%	$ 172,267,790	$ 696,168,936	$ 172,267,790	$ 1,865,863,346	$ (1,084,327,841)	$ 913,159,816
7	3020097600	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	6%	35%	$ 187,346,077	$ 738,392,525	$ 187,346,077	$ 1,935,297,158	$ 850,969,317	$ 962,519,806
8	3104609700	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	7%	35%	$ 202,990,683	$ 781,679,689	$ 781,679,689	$ 2,004,164,652	$ 2,855,133,970	$ 1,011,879,796
9	3189121800	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	7%	36%	$ 219,201,608	$ 826,030,427	$ 826,030,427	$ 2,072,465,827	$ 4,927,599,797	$ 1,061,239,786
10	3273633900	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	7%	37%	$ 235,978,852	$ 871,444,740	$ 871,444,740	$ 2,140,200,683	$ 7,067,800,480	$ 1,110,599,776
11	3358146000	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	8%	37%	$ 253,322,415	$ 917,922,628	$ 917,922,628	$ 2,207,369,220	$ 9,275,169,700	$ 1,159,959,766
12	3442658100	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	8%	38%	$ 271,232,297	$ 965,464,090	$ 965,464,090	$ 2,273,971,438	$ 11,549,141,138	$ 1,209,319,756
13	3527170200	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	8%	39%	$ 289,708,498	$ 1,014,069,127	$ 1,014,069,127	$ 2,340,007,337	$ 13,889,148,475	$ 1,258,679,747
14	3611682300	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	39%	$ 308,751,018	$ 1,063,737,739	$ 1,063,737,739	$ 2,405,476,917	$ 16,294,625,393	$ 1,308,039,737
15	3696194400	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 328,359,857	$ 1,114,469,925	$ 1,114,469,925	$ 2,470,380,178	$ 18,765,005,571	$ 1,357,399,727
16	3780706500	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 340,263,585	$ 1,153,300,854	$ 1,153,300,854	$ 2,542,988,550	$ 21,307,994,122	$ 1,406,759,717
17	3865218600	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 347,869,674	$ 1,187,105,694	$ 1,187,105,694	$ 2,619,894,561	$ 23,927,888,683	$ 1,456,119,707
18	3949730700	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 355,475,763	$ 1,220,910,534	$ 1,220,910,534	$ 2,696,800,572	$ 26,624,689,255	$ 1,505,479,697
19	4034242800	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 363,081,852	$ 1,254,715,374	$ 1,254,715,374	$ 2,773,706,583	$ 29,398,395,838	$ 1,554,839,687
20	4118754900	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 370,687,941	$ 1,288,520,214	$ 1,288,520,214	$ 2,850,612,594	$ 32,249,008,433	$ 1,604,199,677
21	4203267000	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 378,294,030	$ 1,322,325,054	$ 1,322,325,054	$ 2,927,518,605	$ 35,176,527,038	$ 1,653,559,667
22	4287779100	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 385,900,119	$ 1,356,129,894	$ 1,356,129,894	$ 3,004,424,616	$ 38,180,951,654	$ 1,702,919,657
23	4372291200	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 393,506,208	$ 1,389,934,734	$ 1,389,934,734	$ 3,081,330,627	$ 41,262,282,282	$ 1,752,279,647
24	4456803300	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 401,112,297	$ 1,423,739,574	$ 1,423,739,574	$ 3,158,236,638	$ 44,420,518,920	$ 1,801,639,637
25	4541315400	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 408,718,386	$ 1,457,544,414	$ 1,457,544,414	$ 3,235,142,649	$ 47,655,661,569	$ 1,850,999,627
26	4625827500	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 416,324,475	$ 1,491,349,254	$ 1,491,349,254	$ 3,312,048,660	$ 50,967,710,229	$ 1,900,359,617
27	4710339600	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 423,930,564	$ 1,525,154,094	$ 1,525,154,094	$ 3,388,954,671	$ 54,356,664,901	$ 1,949,719,607
28	4794851700	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 431,536,653	$ 1,558,958,934	$ 1,558,958,934	$ 3,465,860,682	$ 57,822,525,583	$ 1,999,079,597
29	4879363800	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 439,142,742	$ 1,592,763,774	$ 1,592,763,774	$ 3,542,766,693	$ 61,365,292,276	$ 2,048,439,587
30	5026050000	0	$ 368,919,999	$ 233,398,367	$ 248,456,326	$ 46,679,673	$ -	9%	40%	$ 452,344,500	$ 1,651,438,254	$ 1,651,438,254	$ 3,676,251,135	$ 65,041,543,412	$ 2,097,799,578

Appendix J. Economic Analysis Framework – Income Tax Calculation (Schedule 4)

Table A17 Dilution income tax calculation

Dilution				Tonnes GHG / bbl Bitumen		0.356				* Current corperat	*Calculation assun	*The corperation v
Year	Revenue (2)	Diluent Expenses (	Extration O&M ex	Upgrader O&M ex	Royalty expenses	Carbon Tax	Opperating Reven	CCA (5)	Current year taxab	Prior Year tax loss	Tax rate	Income tax for the
0	$ -	$ -	$ -	$ -	$ -		$ -	$ 659,256,274	$ (659,256,274)		29%	0
1	$ 3,914,625,000	$ 1,286,990,000	$ 368,919,999	$ 195,753	$ 135,250,294	$ -	$ 2,123,268,954	$ 1,184,755,519	$ 938,513,434	$ (659,256,274)	29%	80984577
2	$ 4,038,849,100	$ 1,356,267,730	$ 368,919,999	$ 195,753	$ 151,365,563	$ -	$ 2,162,100,054	$ 950,680,721	$ 1,211,419,333	$ -	29%	351311607
3	$ 4,163,073,200	$ 1,425,545,460	$ 368,919,999	$ 195,753	$ 168,208,140	$ -	$ 2,200,203,848	$ 775,124,622	$ 1,425,079,225	$ -	29%	413272975
4	$ 4,287,297,300	$ 1,494,823,190	$ 368,919,999	$ 195,753	$ 680,186,256	$ -	$ 1,743,172,102	$ 643,457,548	$ 1,099,714,553	$ -	29%	318917220
5	$ 4,411,521,400	$ 1,564,100,920	$ 368,919,999	$ 195,753	$ 709,629,631	$ -	$ 1,768,675,096	$ 544,707,243	$ 1,223,967,854	$ -	29%	354950678
6	$ 4,535,745,500	$ 1,633,378,650	$ 368,919,999	$ 195,753	$ 739,677,175	$ -	$ 1,793,573,923	$ 470,644,513	$ 1,322,929,410	$ -	29%	383649529
7	$ 4,659,969,600	$ 1,702,656,380	$ 368,919,999	$ 195,753	$ 770,328,886	$ -	$ 1,817,868,581	$ 415,097,466	$ 1,402,771,115	$ -	29%	406803623
8	$ 4,784,193,700	$ 1,771,934,110	$ 368,919,999	$ 195,753	$ 801,584,766	$ -	$ 1,841,559,071	$ 373,437,181	$ 1,468,121,890	$ -	29%	425755348
9	$ 4,908,417,800	$ 1,841,211,840	$ 368,919,999	$ 195,753	$ 833,444,815	$ -	$ 1,864,645,393	$ 342,191,967	$ 1,522,453,425	$ -	29%	441511493
10	$ 5,032,641,900	$ 1,910,489,570	$ 368,919,999	$ 195,753	$ 865,909,031	$ -	$ 1,887,127,546	$ 318,758,057	$ 1,568,369,489	$ -	29%	454827152
11	$ 5,156,866,000	$ 1,979,767,300	$ 368,919,999	$ 195,753	$ 898,977,416	$ -	$ 1,909,005,531	$ 301,182,624	$ 1,607,822,907	$ -	29%	466268643
12	$ 5,281,090,100	$ 2,049,045,030	$ 368,919,999	$ 195,753	$ 932,649,970	$ -	$ 1,930,279,348	$ 288,001,050	$ 1,642,278,298	$ -	29%	476260707
13	$ 5,405,314,200	$ 2,118,322,760	$ 368,919,999	$ 195,753	$ 966,926,691	$ -	$ 1,950,948,996	$ 278,114,869	$ 1,672,834,128	$ -	29%	485121897
14	$ 5,529,538,300	$ 2,187,600,490	$ 368,919,999	$ 195,753	$ 1,001,807,581	$ -	$ 1,971,014,477	$ 270,700,233	$ 1,700,314,244	$ -	29%	493091131
15	$ 5,653,762,400	$ 2,256,878,220	$ 368,919,999	$ 195,753	$ 1,037,292,639	$ -	$ 1,990,475,788	$ 265,139,256	$ 1,725,336,532	$ -	29%	500347594
16	$ 5,777,986,500	$ 2,326,155,950	$ 368,919,999	$ 195,753	$ 1,073,381,866	$ -	$ 2,009,332,932	$ 260,968,524	$ 1,748,364,408	$ -	29%	507025678
17	$ 5,902,210,600	$ 2,395,433,680	$ 368,919,999	$ 195,753	$ 1,110,075,260	$ -	$ 2,027,585,907	$ 257,840,474	$ 1,769,745,433	$ -	29%	513226176
18	$ 6,026,434,700	$ 2,464,711,410	$ 368,919,999	$ 195,753	$ 1,147,372,824	$ -	$ 2,045,234,714	$ 255,494,437	$ 1,789,740,277	$ -	29%	519024680
19	$ 6,150,658,800	$ 2,533,989,140	$ 368,919,999	$ 195,753	$ 1,185,274,555	$ -	$ 2,062,279,353	$ 253,734,909	$ 1,808,544,443	$ -	29%	524477889
20	$ 6,274,882,900	$ 2,603,266,870	$ 368,919,999	$ 195,753	$ 1,221,617,581	$ -	$ 2,080,882,697	$ 252,415,263	$ 1,828,467,434	$ -	29%	530255556
21	$ 6,399,107,000	$ 2,672,544,600	$ 368,919,999	$ 195,753	$ 1,243,596,129	$ -	$ 2,113,850,519	$ 251,425,529	$ 1,862,424,990	$ -	29%	540103247
22	$ 6,523,331,100	$ 2,741,822,330	$ 368,919,999	$ 195,753	$ 1,265,574,677	$ -	$ 2,146,818,341	$ 250,683,228	$ 1,896,135,113	$ -	29%	549879183
23	$ 6,647,555,200	$ 2,811,100,060	$ 368,919,999	$ 195,753	$ 1,287,553,225	$ -	$ 2,179,786,163	$ 250,126,503	$ 1,929,659,660	$ -	29%	559601301
24	$ 6,771,779,300	$ 2,880,377,790	$ 368,919,999	$ 195,753	$ 1,309,531,773	$ -	$ 2,212,753,985	$ 249,708,958	$ 1,963,045,026	$ -	29%	569283058
25	$ 6,896,003,400	$ 2,949,655,520	$ 368,919,999	$ 195,753	$ 1,331,510,321	$ -	$ 2,245,721,807	$ 249,395,800	$ 1,996,326,007	$ -	29%	578934542
26	$ 7,020,227,500	$ 3,018,933,250	$ 368,919,999	$ 195,753	$ 1,353,488,869	$ -	$ 2,278,689,629	$ 249,160,932	$ 2,029,528,697	$ -	29%	588563322
27	$ 7,144,451,600	$ 3,088,210,980	$ 368,919,999	$ 195,753	$ 1,375,467,417	$ -	$ 2,311,657,451	$ 248,984,780	$ 2,062,672,671	$ -	29%	598175075
28	$ 7,268,675,700	$ 3,157,488,710	$ 368,919,999	$ 195,753	$ 1,397,445,965	$ -	$ 2,344,625,273	$ 248,852,667	$ 2,095,772,606	$ -	29%	607774056
29	$ 7,392,899,800	$ 3,226,766,440	$ 368,919,999	$ 195,753	$ 1,419,424,513	$ -	$ 2,377,593,095	$ 248,753,581	$ 2,128,839,514	$ -	29%	617363459
30	$ 7,516,080,000	$ 3,295,950,000	$ 368,919,999	$ 195,753	$ 1,441,023,169	$ -	$ 2,409,991,079	$ 248,679,267	$ 2,161,311,811	$ -	29%	626780425

Table A18 CSC partial-upgrading with pitch income tax calculation

Partial with pitch				Tonnes GHG / bbl Bitumen		0.302			High Upgrader	0.015	Low Upgra	-0.011
Year	Revenue (2)	Diluent Expenses	Extration O&M e	Upgrader O&M e	Royalty expenses	Carbon Tax	Opperating Reven	CCA (5)	Current year taxab	Prior Year tax loss	Tax rate	Income tax f
0	$ -	$ -	$ -	$ -	$ -		$ -	$ 908,785,712	$ (908,785,712)		29%	0
1	$ 3,038,625,000	$ 658,460,000	$ 368,919,999	$ 149,000,000	$ 104,984,494	$ -	$ 1,757,260,507	$1,622,937,833	$ 134,322,674	$ (908,785,712)	29%	0
2	$ 3,135,050,700	$ 693,904,420	$ 368,919,999	$ 149,000,000	$ 117,493,549	$ -	$ 1,805,732,732	$1,282,329,048	$ 523,403,684	$ (774,463,038)	29%	0
3	$ 3,231,476,400	$ 729,348,840	$ 368,919,999	$ 149,000,000	$ 130,567,158	$ -	$ 1,853,640,403	$1,026,872,459	$ 826,767,944	$ (251,059,355)	29%	166955491
4	$ 3,327,902,100	$ 764,793,260	$ 368,919,999	$ 149,000,000	$ 144,205,319	$ -	$ 1,900,983,522	$ 835,280,018	$ 1,065,703,504	$ -	29%	309054016
5	$ 3,424,327,800	$ 800,237,680	$ 368,919,999	$ 149,000,000	$ 158,408,034	$ -	$ 1,947,762,087	$ 691,585,687	$ 1,256,176,400	$ -	29%	364291156
6	$ 3,520,753,500	$ 835,682,100	$ 368,919,999	$ 149,000,000	$ 617,256,546	$ -	$ 1,549,894,855	$ 583,814,938	$ 966,079,917	$ -	29%	280163176
7	$ 3,617,179,200	$ 871,126,520	$ 368,919,999	$ 149,000,000	$ 647,816,201	$ -	$ 1,580,316,480	$ 502,986,877	$ 1,077,329,603	$ -	29%	312425585
8	$ 3,713,604,900	$ 906,570,940	$ 368,919,999	$ 149,000,000	$ 679,046,381	$ -	$ 1,610,067,580	$ 442,365,831	$ 1,167,701,749	$ -	29%	338633507
9	$ 3,810,030,600	$ 942,015,360	$ 368,919,999	$ 149,000,000	$ 710,947,088	$ -	$ 1,639,148,153	$ 396,900,047	$ 1,242,248,107	$ -	29%	360251951
10	$ 3,906,456,300	$ 977,459,780	$ 368,919,999	$ 149,000,000	$ 743,518,320	$ -	$ 1,667,558,201	$ 362,800,708	$ 1,304,757,493	$ -	29%	378379673
11	$ 4,002,882,000	$ 1,012,904,200	$ 368,919,999	$ 149,000,000	$ 776,760,077	$ -	$ 1,695,297,724	$ 337,226,204	$ 1,358,071,519	$ -	29%	393840741
12	$ 4,099,307,700	$ 1,048,348,620	$ 368,919,999	$ 149,000,000	$ 810,672,361	$ -	$ 1,722,366,720	$ 318,045,327	$ 1,404,321,393	$ -	29%	407253204
13	$ 4,195,733,400	$ 1,083,793,040	$ 368,919,999	$ 149,000,000	$ 845,255,170	$ -	$ 1,748,765,191	$ 303,659,668	$ 1,445,105,523	$ -	29%	419080602
14	$ 4,292,159,100	$ 1,119,237,460	$ 368,919,999	$ 149,000,000	$ 880,508,505	$ -	$ 1,774,493,136	$ 292,870,424	$ 1,481,622,711	$ -	29%	429670586
15	$ 4,388,584,800	$ 1,154,681,880	$ 368,919,999	$ 149,000,000	$ 916,432,366	$ -	$ 1,799,550,555	$ 284,778,492	$ 1,514,772,063	$ -	29%	439283898
16	$ 4,485,010,500	$ 1,190,126,300	$ 368,919,999	$ 149,000,000	$ 953,026,753	$ -	$ 1,823,937,448	$ 278,709,542	$ 1,545,227,906	$ -	29%	448116093
17	$ 4,581,436,200	$ 1,225,570,720	$ 368,919,999	$ 149,000,000	$ 990,291,665	$ -	$ 1,847,653,816	$ 274,157,830	$ 1,573,495,986	$ -	29%	456313836
18	$ 4,677,861,900	$ 1,261,015,140	$ 368,919,999	$ 149,000,000	$ 1,028,227,103	$ -	$ 1,870,699,658	$ 270,744,046	$ 1,599,955,612	$ -	29%	463987127
19	$ 4,774,287,600	$ 1,296,459,560	$ 368,919,999	$ 149,000,000	$ 1,066,833,067	$ -	$ 1,893,074,974	$ 268,183,707	$ 1,624,891,266	$ -	29%	471218467
20	$ 4,870,713,300	$ 1,331,903,980	$ 368,919,999	$ 149,000,000	$ 1,104,154,651	$ -	$ 1,916,734,670	$ 266,263,454	$ 1,650,471,216	$ -	29%	478636653
21	$ 4,967,139,000	$ 1,367,348,400	$ 368,919,999	$ 149,000,000	$ 1,128,547,163	$ -	$ 1,953,323,438	$ 264,823,264	$ 1,688,500,174	$ -	29%	489665051
22	$ 5,063,564,700	$ 1,402,792,820	$ 368,919,999	$ 149,000,000	$ 1,152,939,675	$ -	$ 1,989,912,206	$ 263,743,121	$ 1,726,169,085	$ -	29%	500589035
23	$ 5,159,990,400	$ 1,438,237,240	$ 368,919,999	$ 149,000,000	$ 1,177,332,187	$ -	$ 2,026,500,974	$ 262,933,014	$ 1,763,567,960	$ -	29%	511434708
24	$ 5,256,416,100	$ 1,473,681,660	$ 368,919,999	$ 149,000,000	$ 1,201,724,699	$ -	$ 2,063,089,742	$ 262,325,434	$ 1,800,764,308	$ -	29%	522221649
25	$ 5,352,841,800	$ 1,509,126,080	$ 368,919,999	$ 149,000,000	$ 1,226,117,211	$ -	$ 2,099,678,510	$ 261,869,749	$ 1,837,808,761	$ -	29%	532964541
26	$ 5,449,267,500	$ 1,544,570,500	$ 368,919,999	$ 149,000,000	$ 1,250,509,723	$ -	$ 2,136,267,278	$ 261,527,985	$ 1,874,739,293	$ -	29%	543674395
27	$ 5,545,693,200	$ 1,580,014,920	$ 368,919,999	$ 149,000,000	$ 1,274,902,235	$ -	$ 2,172,856,046	$ 261,271,662	$ 1,911,584,384	$ -	29%	554359471
28	$ 5,642,118,900	$ 1,615,459,340	$ 368,919,999	$ 149,000,000	$ 1,299,294,747	$ -	$ 2,209,444,814	$ 261,079,420	$ 1,948,365,394	$ -	29%	565025964
29	$ 5,738,544,600	$ 1,650,903,760	$ 368,919,999	$ 149,000,000	$ 1,323,687,259	$ -	$ 2,246,033,582	$ 260,935,238	$ 1,985,098,344	$ -	29%	575678520
30	$ 5,834,160,000	$ 1,686,300,000	$ 368,919,999	$ 149,000,000	$ 1,347,774,923	$ -	$ 2,282,165,078	$ 260,827,102	$ 2,021,337,976	$ -	29%	586188013

Table A19 CSC partial-upgrading without pitch income tax calculation

Partial wo pitch					Tonnes GHG / bbl Bitumen	0.179			High Upgrader	0.015	Low Upgra	-0.011
Year	Revenue (2)	Diluent Expense	Extration O&M e	Upgrader O&M	Royalty expenses	Carbon Tax	Opperating Reven	CCA (5)	Current year taxab	Prior Year tax loss	Tax rate	Income tax for th
0	$ -	$ -	$ -	$ -	$ -		$ -	$ 908,785,712	$ (908,785,712)		29%	$ -
1	$ 2,764,875,000	$ 389,090,000	$ 368,919,999	$ 149,000,000	$ 95,526,431	$ -	$ 1,762,338,570	$1,622,937,833	$ 139,400,737	$ (908,785,712)	29%	$ -
2	$ 2,852,613,700	$ 410,034,430	$ 368,919,999	$ 149,000,000	$ 106,908,545	$ -	$ 1,817,750,726	$1,282,329,048	$ 535,421,678	$ (769,384,976)	29%	$ -
3	$ 2,940,352,400	$ 430,978,860	$ 368,919,999	$ 149,000,000	$ 118,804,351	$ -	$ 1,872,649,190	$1,026,872,459	$ 845,776,731	$ (233,963,298)	29%	$ 177,425,896
4	$ 3,028,091,100	$ 451,923,290	$ 368,919,999	$ 149,000,000	$ 131,213,849	$ -	$ 1,927,033,962	$ 835,280,018	$ 1,091,753,944	$ -	29%	$ 316,608,644
5	$ 3,115,829,800	$ 472,867,720	$ 368,919,999	$ 149,000,000	$ 593,373,252	$ -	$ 1,531,668,829	$ 691,585,687	$ 840,083,142	$ -	29%	$ 243,624,111
6	$ 3,203,568,500	$ 493,812,150	$ 368,919,999	$ 149,000,000	$ 625,248,027	$ -	$ 1,566,588,324	$ 583,814,938	$ 982,773,386	$ -	29%	$ 285,004,282
7	$ 3,291,307,200	$ 514,756,580	$ 368,919,999	$ 149,000,000	$ 657,857,245	$ -	$ 1,600,773,376	$ 502,986,877	$ 1,097,786,499	$ -	29%	$ 318,358,085
8	$ 3,379,045,900	$ 535,701,010	$ 368,919,999	$ 149,000,000	$ 691,200,906	$ -	$ 1,634,223,985	$ 442,365,831	$ 1,191,858,154	$ -	29%	$ 345,638,865
9	$ 3,466,784,600	$ 556,645,440	$ 368,919,999	$ 149,000,000	$ 725,279,010	$ -	$ 1,666,940,151	$ 396,900,047	$ 1,270,040,105	$ -	29%	$ 368,311,630
10	$ 3,554,523,300	$ 577,589,870	$ 368,919,999	$ 149,000,000	$ 760,091,557	$ -	$ 1,698,921,874	$ 362,800,708	$ 1,336,121,166	$ -	29%	$ 387,475,138
11	$ 3,642,262,000	$ 598,534,300	$ 368,919,999	$ 149,000,000	$ 795,638,547	$ -	$ 1,730,169,154	$ 337,226,204	$ 1,392,942,949	$ -	29%	$ 403,953,455
12	$ 3,730,000,700	$ 619,478,730	$ 368,919,999	$ 149,000,000	$ 831,919,981	$ -	$ 1,760,681,990	$ 318,045,327	$ 1,442,636,664	$ -	29%	$ 418,364,633
13	$ 3,817,739,400	$ 640,423,160	$ 368,919,999	$ 149,000,000	$ 868,935,857	$ -	$ 1,790,460,384	$ 303,659,668	$ 1,486,800,716	$ -	29%	$ 431,172,208
14	$ 3,905,478,100	$ 661,367,590	$ 368,919,999	$ 149,000,000	$ 906,686,176	$ -	$ 1,819,504,335	$ 292,870,424	$ 1,526,633,910	$ -	29%	$ 442,723,834
15	$ 3,993,216,800	$ 682,312,020	$ 368,919,999	$ 149,000,000	$ 945,170,939	$ -	$ 1,847,813,842	$ 284,778,492	$ 1,563,035,351	$ -	29%	$ 453,280,252
16	$ 4,080,955,500	$ 703,256,450	$ 368,919,999	$ 149,000,000	$ 984,390,144	$ -	$ 1,875,388,907	$ 278,709,542	$ 1,596,679,365	$ -	29%	$ 463,037,016
17	$ 4,168,694,200	$ 724,200,880	$ 368,919,999	$ 149,000,000	$ 1,024,343,793	$ -	$ 1,902,229,528	$ 274,157,830	$ 1,628,071,698	$ -	29%	$ 472,140,792
18	$ 4,256,432,900	$ 745,145,310	$ 368,919,999	$ 149,000,000	$ 1,065,031,885	$ -	$ 1,928,335,706	$ 270,744,046	$ 1,657,591,661	$ -	29%	$ 480,701,582
19	$ 4,344,171,600	$ 766,089,740	$ 368,919,999	$ 149,000,000	$ 1,106,454,420	$ -	$ 1,953,707,441	$ 268,183,707	$ 1,685,523,734	$ -	29%	$ 488,801,883
20	$ 4,431,910,300	$ 787,034,170	$ 368,919,999	$ 149,000,000	$ 1,146,581,375	$ -	$ 1,980,374,756	$ 266,263,454	$ 1,714,111,302	$ -	29%	$ 497,092,278
21	$ 4,519,649,000	$ 807,978,600	$ 368,919,999	$ 149,000,000	$ 1,173,299,083	$ -	$ 2,020,451,318	$ 264,823,264	$ 1,755,628,054	$ -	29%	$ 509,132,136
22	$ 4,607,387,700	$ 828,923,030	$ 368,919,999	$ 149,000,000	$ 1,200,016,791	$ -	$ 2,060,527,880	$ 263,743,121	$ 1,796,784,759	$ -	29%	$ 521,067,580
23	$ 4,695,126,400	$ 849,867,460	$ 368,919,999	$ 149,000,000	$ 1,226,734,499	$ -	$ 2,100,604,442	$ 262,933,014	$ 1,837,671,428	$ -	29%	$ 532,924,714
24	$ 4,782,865,100	$ 870,811,890	$ 368,919,999	$ 149,000,000	$ 1,253,452,207	$ -	$ 2,140,681,004	$ 262,325,434	$ 1,878,355,570	$ -	29%	$ 544,723,115
25	$ 4,870,603,800	$ 891,756,320	$ 368,919,999	$ 149,000,000	$ 1,280,169,915	$ -	$ 2,180,757,566	$ 261,869,749	$ 1,918,887,817	$ -	29%	$ 556,477,467
26	$ 4,958,342,500	$ 912,700,750	$ 368,919,999	$ 149,000,000	$ 1,306,887,623	$ -	$ 2,220,834,128	$ 261,527,985	$ 1,959,306,143	$ -	29%	$ 568,198,782
27	$ 5,046,081,200	$ 933,645,180	$ 368,919,999	$ 149,000,000	$ 1,333,605,331	$ -	$ 2,260,910,690	$ 261,271,662	$ 1,999,639,028	$ -	29%	$ 579,895,318
28	$ 5,133,819,900	$ 954,589,610	$ 368,919,999	$ 149,000,000	$ 1,360,323,039	$ -	$ 2,300,987,252	$ 261,079,420	$ 2,039,907,832	$ -	29%	$ 591,573,271
29	$ 5,221,558,600	$ 975,534,040	$ 368,919,999	$ 149,000,000	$ 1,387,040,747	$ -	$ 2,341,063,814	$ 260,935,238	$ 2,080,128,576	$ -	29%	$ 603,237,287
30	$ 5,308,560,000	$ 996,450,000	$ 368,919,999	$ 149,000,000	$ 1,413,474,923	$ -	$ 2,380,715,078	$ 260,827,102	$ 2,119,887,976	$ -	29%	$ 614,767,513

Table A20 Coking full-upgrading income tax calculation

coking full				Tonnes	GHG / bbl Bitumen	0.113						
Year	Revenue (2)	Diluent Ex	Extration O&M e	Upgrader O&M (	Royalty expenses	Carbon Tax	Opperating Reven	CCA (5)	Current year taxab	Prior Year tax loss car	Tax rate	Income tax for th
0	$ -	$ -	$ -	$ -	$ -		$ -	$1,402,272,445	$ (1,402,272,445)		29%	$ -
1	$ 2,513,025,000	$ -	$ 368,919,999	$ 233,398,367	$ 105,371,138	$ -	$ 1,805,335,496	$2,490,868,778	$ (685,533,282)	$ (1,402,272,445)	29%	$ -
2	$ 2,597,537,100	$ -	$ 368,919,999	$ 233,398,367	$ 117,617,831	$ -	$ 1,877,600,904	$1,941,935,584	$ (64,334,680)	$ (2,087,805,727)	29%	$ -
3	$ 2,682,049,200	$ -	$ 368,919,999	$ 233,398,367	$ 130,430,842	$ -	$ 1,949,299,992	$1,530,235,687	$ 419,064,305	$ (2,152,140,407)	29%	$ -
4	$ 2,766,561,300	$ -	$ 368,919,999	$ 233,398,367	$ 143,810,172	$ -	$ 2,020,432,762	$1,221,460,765	$ 798,971,997	$ (1,733,076,102)	29%	$ -
5	$ 2,851,073,400	$ -	$ 368,919,999	$ 233,398,367	$ 157,755,821	$ -	$ 2,090,999,213	$ 989,879,574	$ 1,101,119,639	$ (934,104,105)	29%	$ 48,434,505
6	$ 2,935,585,500	$ -	$ 368,919,999	$ 233,398,367	$ 172,267,790	$ -	$ 2,160,999,345	$ 816,193,680	$ 1,344,805,665	$ -	29%	$ 389,993,643
7	$ 3,020,097,600	$ -	$ 368,919,999	$ 233,398,367	$ 187,346,077	$ -	$ 2,230,433,158	$ 685,929,260	$ 1,544,503,898	$ -	29%	$ 447,906,130
8	$ 3,104,609,700	$ -	$ 368,919,999	$ 233,398,367	$ 781,679,689	$ -	$ 1,720,611,646	$ 588,230,945	$ 1,132,380,701	$ -	29%	$ 328,390,403
9	$ 3,189,121,800	$ -	$ 368,919,999	$ 233,398,367	$ 826,030,427	$ -	$ 1,760,773,007	$ 514,957,208	$ 1,245,815,799	$ -	29%	$ 361,286,582
10	$ 3,273,633,900	$ -	$ 368,919,999	$ 233,398,367	$ 871,444,740	$ -	$ 1,799,870,794	$ 460,001,906	$ 1,339,868,888	$ -	29%	$ 388,561,978
11	$ 3,358,146,000	$ -	$ 368,919,999	$ 233,398,367	$ 917,922,628	$ -	$ 1,837,905,007	$ 418,785,429	$ 1,419,119,577	$ -	29%	$ 411,544,677
12	$ 3,442,658,100	$ -	$ 368,919,999	$ 233,398,367	$ 965,464,090	$ -	$ 1,874,875,644	$ 387,873,072	$ 1,487,002,573	$ -	29%	$ 431,230,746
13	$ 3,527,170,200	$ -	$ 368,919,999	$ 233,398,367	$ 1,014,069,127	$ -	$ 1,910,782,707	$ 364,688,804	$ 1,546,093,904	$ -	29%	$ 448,367,232
14	$ 3,611,682,300	$ -	$ 368,919,999	$ 233,398,367	$ 1,063,737,739	$ -	$ 1,945,626,196	$ 347,300,602	$ 1,598,325,593	$ -	29%	$ 463,514,422
15	$ 3,696,194,400	$ -	$ 368,919,999	$ 233,398,367	$ 1,114,469,925	$ -	$ 1,979,406,110	$ 334,259,452	$ 1,645,146,658	$ -	29%	$ 477,092,531
16	$ 3,780,706,500	$ -	$ 368,919,999	$ 233,398,367	$ 1,153,300,854	$ -	$ 2,025,087,280	$ 324,478,589	$ 1,700,608,692	$ -	29%	$ 493,176,521
17	$ 3,865,218,600	$ -	$ 368,919,999	$ 233,398,367	$ 1,187,105,694	$ -	$ 2,075,794,540	$ 317,142,941	$ 1,758,651,599	$ -	29%	$ 510,008,964
18	$ 3,949,730,700	$ -	$ 368,919,999	$ 233,398,367	$ 1,220,910,534	$ -	$ 2,126,501,800	$ 311,641,206	$ 1,814,860,595	$ -	29%	$ 526,309,572
19	$ 4,034,242,800	$ -	$ 368,919,999	$ 233,398,367	$ 1,254,715,374	$ -	$ 2,177,209,060	$ 307,514,904	$ 1,869,694,156	$ -	29%	$ 542,211,305
20	$ 4,118,754,900	$ -	$ 368,919,999	$ 233,398,367	$ 1,288,520,214	$ -	$ 2,227,916,320	$ 304,420,178	$ 1,923,496,143	$ -	29%	$ 557,813,881
21	$ 4,203,267,000	$ -	$ 368,919,999	$ 233,398,367	$ 1,322,325,054	$ -	$ 2,278,623,580	$ 302,099,133	$ 1,976,524,447	$ -	29%	$ 573,192,090
22	$ 4,287,779,100	$ -	$ 368,919,999	$ 233,398,367	$ 1,356,129,894	$ -	$ 2,329,330,840	$ 300,358,350	$ 2,028,972,491	$ -	29%	$ 588,402,022
23	$ 4,372,291,200	$ -	$ 368,919,999	$ 233,398,367	$ 1,389,934,734	$ -	$ 2,380,038,100	$ 299,052,762	$ 2,080,985,338	$ -	29%	$ 603,485,748
24	$ 4,456,803,300	$ -	$ 368,919,999	$ 233,398,367	$ 1,423,739,574	$ -	$ 2,430,745,360	$ 298,073,571	$ 2,132,671,789	$ -	29%	$ 618,474,819
25	$ 4,541,315,400	$ -	$ 368,919,999	$ 233,398,367	$ 1,457,544,414	$ -	$ 2,481,452,620	$ 297,339,178	$ 2,184,113,442	$ -	29%	$ 633,392,898
26	$ 4,625,827,500	$ -	$ 368,919,999	$ 233,398,367	$ 1,491,349,254	$ -	$ 2,532,159,880	$ 296,788,383	$ 2,235,371,497	$ -	29%	$ 648,257,734
27	$ 4,710,339,600	$ -	$ 368,919,999	$ 233,398,367	$ 1,525,154,094	$ -	$ 2,582,867,140	$ 296,375,287	$ 2,286,491,853	$ -	29%	$ 663,082,637
28	$ 4,794,851,700	$ -	$ 368,919,999	$ 233,398,367	$ 1,558,958,934	$ -	$ 2,633,574,400	$ 296,065,465	$ 2,337,508,935	$ -	29%	$ 677,877,591
29	$ 4,879,363,800	$ -	$ 368,919,999	$ 233,398,367	$ 1,592,763,774	$ -	$ 2,684,281,660	$ 295,833,099	$ 2,388,448,562	$ -	29%	$ 692,650,083
30	$ 5,026,050,000	$ -	$ 368,919,999	$ 233,398,367	$ 1,651,438,254	$ -	$ 2,772,293,380	$ 295,658,824	$ 2,476,634,556	$ -	29%	$ 718,224,021

Appendix K. Economic Analysis Framework – Tax Depreciation on Capital Allowance Calculation (Schedule 5)

Table A21 Dilution tax depreciation on capital allowance calculation

DILUTION	Note: Assumes all capital assets will fall into class 41.1 (Oil Sands) for Canadian income tax purposes. (25% capital cost rate per year rema							
Year	Opening UCC	Additions Ext Cap	Additions Up/D	Proceeds fror	Net Balance	1/2 year rule	depreciable Balar	Capital Cost allowa
0	$ -	$ 5,270,285,699	$ 3,764,490	$ -	$5,274,050,189	$2,637,025,094	$ 2,637,025,094	$ 659,256,274
1	$4,614,793,915	$ 248,456,326	$ -	$ -	$4,863,250,241	$ 124,228,163	$ 4,739,022,078	$ 1,184,755,519
2	$3,678,494,721	$ 248,456,326	$ -	$ -	$3,926,951,047	$ 124,228,163	$ 3,802,722,884	$ 950,680,721
3	$2,976,270,326	$ 248,456,326	$ -	$ -	$3,224,726,652	$ 124,228,163	$ 3,100,498,489	$ 775,124,622
4	$2,449,602,030	$ 248,456,326	$ -	$ -	$2,698,058,355	$ 124,228,163	$ 2,573,830,193	$ 643,457,548
5	$2,054,600,807	$ 248,456,326	$ -	$ -	$2,303,057,133	$ 124,228,163	$ 2,178,828,970	$ 544,707,243
6	$1,758,349,891	$ 248,456,326	$ -	$ -	$2,006,806,216	$ 124,228,163	$ 1,882,578,053	$ 470,644,513
7	$1,536,161,703	$ 248,456,326	$ -	$ -	$1,784,618,029	$ 124,228,163	$ 1,660,389,866	$ 415,097,466
8	$1,369,520,562	$ 248,456,326	$ -	$ -	$1,617,976,888	$ 124,228,163	$ 1,493,748,725	$ 373,437,181
9	$1,244,539,707	$ 248,456,326	$ -	$ -	$1,492,996,033	$ 124,228,163	$ 1,368,767,870	$ 342,191,967
10	$1,150,804,065	$ 248,456,326	$ -	$ -	$1,399,260,391	$ 124,228,163	$ 1,275,032,228	$ 318,758,057
11	$1,080,502,334	$ 248,456,326	$ -	$ -	$1,328,958,660	$ 124,228,163	$ 1,204,730,497	$ 301,182,624
12	$1,027,776,036	$ 248,456,326	$ -	$ -	$1,276,232,361	$ 124,228,163	$ 1,152,004,198	$ 288,001,050
13	$ 988,231,312	$ 248,456,326	$ -	$ -	$1,236,687,638	$ 124,228,163	$ 1,112,459,475	$ 278,114,869
14	$ 958,572,769	$ 248,456,326	$ -	$ -	$1,207,029,095	$ 124,228,163	$ 1,082,800,932	$ 270,700,233
15	$ 936,328,862	$ 248,456,326	$ -	$ -	$1,184,785,188	$ 124,228,163	$ 1,060,557,025	$ 265,139,256
16	$ 919,645,931	$ 248,456,326	$ -	$ -	$1,168,102,257	$ 124,228,163	$ 1,043,874,094	$ 260,968,524
17	$ 907,133,734	$ 248,456,326	$ -	$ -	$1,155,590,059	$ 124,228,163	$ 1,031,361,897	$ 257,840,474
18	$ 897,749,585	$ 248,456,326	$ -	$ -	$1,146,205,911	$ 124,228,163	$ 1,021,977,748	$ 255,494,437
19	$ 890,711,474	$ 248,456,326	$ -	$ -	$1,139,167,800	$ 124,228,163	$ 1,014,939,637	$ 253,734,909
20	$ 885,432,891	$ 248,456,326	$ -	$ -	$1,133,889,216	$ 124,228,163	$ 1,009,661,054	$ 252,415,263
21	$ 881,473,953	$ 248,456,326	$ -	$ -	$1,129,930,279	$ 124,228,163	$ 1,005,702,116	$ 251,425,529
22	$ 878,504,750	$ 248,456,326	$ -	$ -	$1,126,961,076	$ 124,228,163	$ 1,002,732,913	$ 250,683,228
23	$ 876,277,847	$ 248,456,326	$ -	$ -	$1,124,734,173	$ 124,228,163	$ 1,000,506,010	$ 250,126,503
24	$ 874,607,671	$ 248,456,326	$ -	$ -	$1,123,063,996	$ 124,228,163	$ 998,835,834	$ 249,708,958
25	$ 873,355,038	$ 248,456,326	$ -	$ -	$1,121,811,364	$ 124,228,163	$ 997,583,201	$ 249,395,800
26	$ 872,415,564	$ 248,456,326	$ -	$ -	$1,120,871,889	$ 124,228,163	$ 996,643,727	$ 249,160,932
27	$ 871,710,958	$ 248,456,326	$ -	$ -	$1,120,167,284	$ 124,228,163	$ 995,939,121	$ 248,984,780
28	$ 871,182,503	$ 248,456,326	$ -	$ -	$1,119,638,829	$ 124,228,163	$ 995,410,666	$ 248,852,667
29	$ 870,786,163	$ 248,456,326	$ -	$ -	$1,119,242,488	$ 124,228,163	$ 995,014,326	$ 248,753,581
30	$ 870,488,907	$ 248,456,326	$ -	$ -	$1,118,945,233	$ 124,228,163	$ 994,717,070	$ 248,679,267

Table A22 CSC partial-upgrading with pitch tax depreciation on capital allowance calculation

early additions will be subject to the half year rule)								
Year	Opening UCC	Additions Ext Cap	Additions Up/Dil C	Proceeds f	Net Balance	1/2 year rule	depreciable Balan	Capital Cost allov
0	$ -	$ 5,270,285,699	$ 2,000,000,000	$ -	$ 7,270,285,699	$ 3,635,142,849	$ 3,635,142,849	$ 908,785,712
1	$6,361,499,986	$ 248,456,326	$ 12,046,367	$ -	$ 6,622,002,680	$ 130,251,347	$ 6,491,751,333	$1,622,937,833
2	$4,999,064,846	$ 248,456,326	$ 12,046,367	$ -	$ 5,259,567,539	$ 130,251,347	$ 5,129,316,193	$1,282,329,048
3	$3,977,238,491	$ 248,456,326	$ 12,046,367	$ -	$ 4,237,741,184	$ 130,251,347	$ 4,107,489,838	$1,026,872,459
4	$3,210,868,725	$ 248,456,326	$ 12,046,367	$ -	$ 3,471,371,418	$ 130,251,347	$ 3,341,120,071	$ 835,280,018
5	$2,636,091,400	$ 248,456,326	$ 12,046,367	$ -	$ 2,896,594,093	$ 130,251,347	$ 2,766,342,747	$ 691,585,687
6	$2,205,008,407	$ 248,456,326	$ 12,046,367	$ -	$ 2,465,511,100	$ 130,251,347	$ 2,335,259,753	$ 583,814,938
7	$1,881,696,161	$ 248,456,326	$ 12,046,367	$ -	$ 2,142,198,855	$ 130,251,347	$ 2,011,947,508	$ 502,986,877
8	$1,639,211,978	$ 248,456,326	$ 12,046,367	$ -	$ 1,899,714,671	$ 130,251,347	$ 1,769,463,324	$ 442,365,831
9	$1,457,348,840	$ 248,456,326	$ 12,046,367	$ -	$ 1,717,851,533	$ 130,251,347	$ 1,587,600,186	$ 396,900,047
10	$1,320,951,486	$ 248,456,326	$ 12,046,367	$ -	$ 1,581,454,179	$ 130,251,347	$ 1,451,202,833	$ 362,800,708
11	$1,218,653,471	$ 248,456,326	$ 12,046,367	$ -	$ 1,479,156,164	$ 130,251,347	$ 1,348,904,818	$ 337,226,204
12	$1,141,929,960	$ 248,456,326	$ 12,046,367	$ -	$ 1,402,432,653	$ 130,251,347	$ 1,272,181,306	$ 318,045,327
13	$1,084,387,326	$ 248,456,326	$ 12,046,367	$ -	$ 1,344,890,019	$ 130,251,347	$ 1,214,638,673	$ 303,659,668
14	$1,041,230,351	$ 248,456,326	$ 12,046,367	$ -	$ 1,301,733,044	$ 130,251,347	$ 1,171,481,698	$ 292,870,424
15	$1,008,862,620	$ 248,456,326	$ 12,046,367	$ -	$ 1,269,365,313	$ 130,251,347	$ 1,139,113,966	$ 284,778,492
16	$ 984,586,821	$ 248,456,326	$ 12,046,367	$ -	$ 1,245,089,515	$ 130,251,347	$ 1,114,838,168	$ 278,709,542
17	$ 966,379,973	$ 248,456,326	$ 12,046,367	$ -	$ 1,226,882,666	$ 130,251,347	$ 1,096,631,319	$ 274,157,830
18	$ 952,724,836	$ 248,456,326	$ 12,046,367	$ -	$ 1,213,227,529	$ 130,251,347	$ 1,082,976,182	$ 270,744,046
19	$ 942,483,483	$ 248,456,326	$ 12,046,367	$ -	$ 1,202,986,176	$ 130,251,347	$ 1,072,734,830	$ 268,183,707
20	$ 934,802,469	$ 248,456,326	$ 12,046,367	$ -	$ 1,195,305,162	$ 130,251,347	$ 1,065,053,816	$ 266,263,454
21	$ 929,041,708	$ 248,456,326	$ 12,046,367	$ -	$ 1,189,544,401	$ 130,251,347	$ 1,059,293,055	$ 264,823,264
22	$ 924,721,138	$ 248,456,326	$ 12,046,367	$ -	$ 1,185,223,831	$ 130,251,347	$ 1,054,972,484	$ 263,743,121
23	$ 921,480,710	$ 248,456,326	$ 12,046,367	$ -	$ 1,181,983,403	$ 130,251,347	$ 1,051,732,056	$ 262,933,014
24	$ 919,050,389	$ 248,456,326	$ 12,046,367	$ -	$ 1,179,553,082	$ 130,251,347	$ 1,049,301,735	$ 262,325,434
25	$ 917,227,648	$ 248,456,326	$ 12,046,367	$ -	$ 1,177,730,341	$ 130,251,347	$ 1,047,478,995	$ 261,869,749
26	$ 915,860,592	$ 248,456,326	$ 12,046,367	$ -	$ 1,176,363,286	$ 130,251,347	$ 1,046,111,939	$ 261,527,985
27	$ 914,835,301	$ 248,456,326	$ 12,046,367	$ -	$ 1,175,337,994	$ 130,251,347	$ 1,045,086,647	$ 261,271,662
28	$ 914,066,332	$ 248,456,326	$ 12,046,367	$ -	$ 1,174,569,025	$ 130,251,347	$ 1,044,317,679	$ 261,079,420
29	$ 913,489,606	$ 248,456,326	$ 12,046,367	$ -	$ 1,173,992,299	$ 130,251,347	$ 1,043,740,952	$ 260,935,238
30	$ 913,057,061	$ 248,456,326	$ 12,046,367	$ -	$ 1,173,559,754	$ 130,251,347	$ 1,043,308,407	$ 260,827,102

Table A23 CSC partial-upgrading without pitch tax depreciation on capital allowance calculation

Year	Opening UCC	Additions Ext Cap	Additions Up/Dil C	Proceeds f	Net Balance	1/2 year rule	depreciable Balan	Capital Cost allov
0	$ -	$ 5,270,285,699	$ 2,000,000,000	$ -	$ 7,270,285,699	$ 3,635,142,849	$ 3,635,142,849	$ 908,785,712
1	$6,361,499,986	$ 248,456,326	$ 12,046,367	$ -	$ 6,622,002,680	$ 130,251,347	$ 6,491,751,333	$1,622,937,833
2	$4,999,064,846	$ 248,456,326	$ 12,046,367	$ -	$ 5,259,567,539	$ 130,251,347	$ 5,129,316,193	$1,282,329,048
3	$3,977,238,491	$ 248,456,326	$ 12,046,367	$ -	$ 4,237,741,184	$ 130,251,347	$ 4,107,489,838	$1,026,872,459
4	$3,210,868,725	$ 248,456,326	$ 12,046,367	$ -	$ 3,471,371,418	$ 130,251,347	$ 3,341,120,071	$ 835,280,018
5	$2,636,091,400	$ 248,456,326	$ 12,046,367	$ -	$ 2,896,594,093	$ 130,251,347	$ 2,766,342,747	$ 691,585,687
6	$2,205,008,407	$ 248,456,326	$ 12,046,367	$ -	$ 2,465,511,100	$ 130,251,347	$ 2,335,259,753	$ 583,814,938
7	$1,881,696,161	$ 248,456,326	$ 12,046,367	$ -	$ 2,142,198,855	$ 130,251,347	$ 2,011,947,508	$ 502,986,877
8	$1,639,211,978	$ 248,456,326	$ 12,046,367	$ -	$ 1,899,714,671	$ 130,251,347	$ 1,769,463,324	$ 442,365,831
9	$1,457,348,840	$ 248,456,326	$ 12,046,367	$ -	$ 1,717,851,533	$ 130,251,347	$ 1,587,600,186	$ 396,900,047
10	$1,320,951,486	$ 248,456,326	$ 12,046,367	$ -	$ 1,581,454,179	$ 130,251,347	$ 1,451,202,833	$ 362,800,708
11	$1,218,653,471	$ 248,456,326	$ 12,046,367	$ -	$ 1,479,156,164	$ 130,251,347	$ 1,348,904,818	$ 337,226,204
12	$1,141,929,960	$ 248,456,326	$ 12,046,367	$ -	$ 1,402,432,653	$ 130,251,347	$ 1,272,181,306	$ 318,045,327
13	$1,084,387,326	$ 248,456,326	$ 12,046,367	$ -	$ 1,344,890,019	$ 130,251,347	$ 1,214,638,673	$ 303,659,668
14	$1,041,230,351	$ 248,456,326	$ 12,046,367	$ -	$ 1,301,733,044	$ 130,251,347	$ 1,171,481,698	$ 292,870,424
15	$1,008,862,620	$ 248,456,326	$ 12,046,367	$ -	$ 1,269,365,313	$ 130,251,347	$ 1,139,113,966	$ 284,778,492
16	$ 984,586,821	$ 248,456,326	$ 12,046,367	$ -	$ 1,245,089,515	$ 130,251,347	$ 1,114,838,168	$ 278,709,542
17	$ 966,379,973	$ 248,456,326	$ 12,046,367	$ -	$ 1,226,882,666	$ 130,251,347	$ 1,096,631,319	$ 274,157,830
18	$ 952,724,836	$ 248,456,326	$ 12,046,367	$ -	$ 1,213,227,529	$ 130,251,347	$ 1,082,976,182	$ 270,744,046
19	$ 942,483,483	$ 248,456,326	$ 12,046,367	$ -	$ 1,202,986,176	$ 130,251,347	$ 1,072,734,830	$ 268,183,707
20	$ 934,802,469	$ 248,456,326	$ 12,046,367	$ -	$ 1,195,305,162	$ 130,251,347	$ 1,065,053,816	$ 266,263,454
21	$ 929,041,708	$ 248,456,326	$ 12,046,367	$ -	$ 1,189,544,401	$ 130,251,347	$ 1,059,293,055	$ 264,823,264
22	$ 924,721,138	$ 248,456,326	$ 12,046,367	$ -	$ 1,185,223,831	$ 130,251,347	$ 1,054,972,484	$ 263,743,121
23	$ 921,480,710	$ 248,456,326	$ 12,046,367	$ -	$ 1,181,983,403	$ 130,251,347	$ 1,051,732,056	$ 262,933,014
24	$ 919,050,389	$ 248,456,326	$ 12,046,367	$ -	$ 1,179,553,082	$ 130,251,347	$ 1,049,301,735	$ 262,325,434
25	$ 917,227,648	$ 248,456,326	$ 12,046,367	$ -	$ 1,177,730,341	$ 130,251,347	$ 1,047,478,995	$ 261,869,749
26	$ 915,860,592	$ 248,456,326	$ 12,046,367	$ -	$ 1,176,363,286	$ 130,251,347	$ 1,046,111,939	$ 261,527,985
27	$ 914,835,301	$ 248,456,326	$ 12,046,367	$ -	$ 1,175,337,994	$ 130,251,347	$ 1,045,086,647	$ 261,271,662
28	$ 914,066,332	$ 248,456,326	$ 12,046,367	$ -	$ 1,174,569,025	$ 130,251,347	$ 1,044,317,679	$ 261,079,420
29	$ 913,489,606	$ 248,456,326	$ 12,046,367	$ -	$ 1,173,992,299	$ 130,251,347	$ 1,043,740,952	$ 260,935,238
30	$ 913,057,061	$ 248,456,326	$ 12,046,367	$ -	$ 1,173,559,754	$ 130,251,347	$ 1,043,308,407	$ 260,827,102

Table A24 Coking full-upgrading tax depreciation on capital allowance calculation

Year	Opening UCC	Additions Ext Cap	Additions Up/Dil (	Proceeds f	Net Balance	1/2 year rule	depreciable Balan	Capital Cost allov
0	$ -	$ 5,270,285,699	$ 5,947,893,860	$ -	$ 11,218,179,559	$ 5,609,089,779	$ 5,609,089,779	$1,402,272,445
1	$ 9,815,907,114	$ 248,456,326	$ 46,679,673	$ -	$ 10,111,043,113	$ 147,568,000	$ 9,963,475,114	$2,490,868,778
2	$ 7,620,174,335	$ 248,456,326	$ 46,679,673	$ -	$ 7,915,310,334	$ 147,568,000	$ 7,767,742,334	$1,941,935,584
3	$ 5,973,374,750	$ 248,456,326	$ 46,679,673	$ -	$ 6,268,510,749	$ 147,568,000	$ 6,120,942,750	$1,530,235,687
4	$ 4,738,275,062	$ 248,456,326	$ 46,679,673	$ -	$ 5,033,411,061	$ 147,568,000	$ 4,885,843,062	$1,221,460,765
5	$ 3,811,950,296	$ 248,456,326	$ 46,679,673	$ -	$ 4,107,086,295	$ 147,568,000	$ 3,959,518,295	$ 989,879,574
6	$ 3,117,206,721	$ 248,456,326	$ 46,679,673	$ -	$ 3,412,342,720	$ 147,568,000	$ 3,264,774,721	$ 816,193,680
7	$ 2,596,149,040	$ 248,456,326	$ 46,679,673	$ -	$ 2,891,285,039	$ 147,568,000	$ 2,743,717,040	$ 685,929,260
8	$ 2,205,355,779	$ 248,456,326	$ 46,679,673	$ -	$ 2,500,491,778	$ 147,568,000	$ 2,352,923,779	$ 588,230,945
9	$ 1,912,260,834	$ 248,456,326	$ 46,679,673	$ -	$ 2,207,396,833	$ 147,568,000	$ 2,059,828,833	$ 514,957,208
10	$ 1,692,439,625	$ 248,456,326	$ 46,679,673	$ -	$ 1,987,575,624	$ 147,568,000	$ 1,840,007,624	$ 460,001,906
11	$ 1,527,573,718	$ 248,456,326	$ 46,679,673	$ -	$ 1,822,709,717	$ 147,568,000	$ 1,675,141,717	$ 418,785,429
12	$ 1,403,924,287	$ 248,456,326	$ 46,679,673	$ -	$ 1,699,060,287	$ 147,568,000	$ 1,551,492,287	$ 387,873,072
13	$ 1,311,187,215	$ 248,456,326	$ 46,679,673	$ -	$ 1,606,323,214	$ 147,568,000	$ 1,458,755,214	$ 364,688,804
14	$ 1,241,634,410	$ 248,456,326	$ 46,679,673	$ -	$ 1,536,770,409	$ 147,568,000	$ 1,389,202,410	$ 347,300,602
15	$ 1,189,469,807	$ 248,456,326	$ 46,679,673	$ -	$ 1,484,605,806	$ 147,568,000	$ 1,337,037,807	$ 334,259,452
16	$ 1,150,346,355	$ 248,456,326	$ 46,679,673	$ -	$ 1,445,482,354	$ 147,568,000	$ 1,297,914,354	$ 324,478,589
17	$ 1,121,003,765	$ 248,456,326	$ 46,679,673	$ -	$ 1,416,139,764	$ 147,568,000	$ 1,268,571,765	$ 317,142,941
18	$ 1,098,996,823	$ 248,456,326	$ 46,679,673	$ -	$ 1,394,132,822	$ 147,568,000	$ 1,246,564,823	$ 311,641,206
19	$ 1,082,491,617	$ 248,456,326	$ 46,679,673	$ -	$ 1,377,627,616	$ 147,568,000	$ 1,230,059,616	$ 307,514,904
20	$ 1,070,112,712	$ 248,456,326	$ 46,679,673	$ -	$ 1,365,248,711	$ 147,568,000	$ 1,217,680,711	$ 304,420,178
21	$ 1,060,828,533	$ 248,456,326	$ 46,679,673	$ -	$ 1,355,964,532	$ 147,568,000	$ 1,208,396,533	$ 302,099,133
22	$ 1,053,865,399	$ 248,456,326	$ 46,679,673	$ -	$ 1,349,001,398	$ 147,568,000	$ 1,201,433,399	$ 300,358,350
23	$ 1,048,643,048	$ 248,456,326	$ 46,679,673	$ -	$ 1,343,779,048	$ 147,568,000	$ 1,196,211,048	$ 299,052,762
24	$ 1,044,726,286	$ 248,456,326	$ 46,679,673	$ -	$ 1,339,862,285	$ 147,568,000	$ 1,192,294,285	$ 298,073,571
25	$ 1,041,788,713	$ 248,456,326	$ 46,679,673	$ -	$ 1,336,924,713	$ 147,568,000	$ 1,189,356,713	$ 297,339,178
26	$ 1,039,585,534	$ 248,456,326	$ 46,679,673	$ -	$ 1,334,721,533	$ 147,568,000	$ 1,187,153,534	$ 296,788,383
27	$ 1,037,933,150	$ 248,456,326	$ 46,679,673	$ -	$ 1,333,069,149	$ 147,568,000	$ 1,185,501,150	$ 296,375,287
28	$ 1,036,693,862	$ 248,456,326	$ 46,679,673	$ -	$ 1,331,829,861	$ 147,568,000	$ 1,184,261,861	$ 296,065,465
29	$ 1,035,764,396	$ 248,456,326	$ 46,679,673	$ -	$ 1,330,900,395	$ 147,568,000	$ 1,183,332,395	$ 295,833,099
30	$ 1,035,067,296	$ 248,456,326	$ 46,679,673	$ -	$ 1,330,203,295	$ 147,568,000	$ 1,182,635,295	$ 295,658,824