An Integrated Energy Optimization Model for the Canadian Oil Sands Industry

by

Alberto Betancourt

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I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

The aim of this thesis was to develop a new energy model that predicts the energy infrastructure required to maintain the oil production in the Oil Sands operation at minimum cost. Previous studies in this area have focused on the energy infrastructure for fixed energy demands, i.e., the production schemes that produce synthetic crude oil (SCO) and commercial diluted bitumen remained fixed in the optimal infrastructure calculation. The key novelty of this work is that the model searches simultaneously for the most suitable set of oil production schemes and the corresponding energy infrastructures that satisfy the total production demands under environmental constraints, i.e., CO_2 emissions targets. The proposed modeling tool was validated using historical data and previous simulations studies for the Oil Sands operation in 2003. Likewise, the proposed model was used to study the 2020 Oil Sands operations under three different production scenarios. Also, the 2020 case study was used to show the effect of CO_2 capture constraints on the oil production schemes and the energy producers. The results show that the proposed model is a practical tool to determine the production costs for the Oil Sands operations, evaluate future production schemes and energy demands scenarios, and identify the key parameters that affect the Oil Sands operation.

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I thank my mother for her persistent encouragement and kind words during my study time, family and friends who believed in me.

I thank God for allowing me to pursue my goals and dreams, for my family and friends.

To my family and friends.

Thanks for believing in me

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Nomenclature

ASU = air separation unit

ATB = atmospheric topped bitumen

CANMET = Canada Centre for Mineral and Energy Technology

CBM = coal bed methane

CCS = carbon capture and storage

CO_2e = carbon dioxide equivalent

DC = Delayed Coking

DRU = Diluent Recovery Unit

EIA = US Energy Information Administration

EOR = enhanced oil recovery

FC = Fluid Coking

GHG = Greenhouse Gas

H = hydrotreatment

HGO = heavy gas oil

HRSG = heat recovery steam generator

HTS = high temperature shift reaction

HW = hot water

IEA = International Energy Agency

IGCC = integrated gasification combined cycle

LCF = LC-Fining

LGO = light gas oil

MEA = monoethanol amine

NGCC = natural gas combine cycle

NT = naphtha

PSA = Pressure Swing Adsorption

R1 = DC + H

R2 = LCF + H

R3 = LCF + FC + H

S = process steam

SAGD = Steam Assisted Gravity Drainage

SB = natural gas fired boilers

SCO = synthetic crude oil

SCPC = supercritical pulverized coal

SMR = Steam methane reforming

SSE = SAGD steam

SSEB = SAGD steam boilers

VDU = vacuum distillation unit

VTB = vacuum topped bitumen

WCSB = Western Canada Sedimentary Basin

WGS = water gas shift reaction

Model Variables

ACC_j = annual capital cost of hydrogen plant *j* [$/year]

ACC_m = annual capital cost of power plant *m* [$/year]

ACF_j = amortization capital factor for hydrogen plant *j* [%]

ACF_m = amortization capital factor for power plant *m* [%]

$ATBF_i$ = atmospheric topped bitumen feeding the LC-finers in SCO scheme *i* [tonne/h]

ATB_i = atmospheric topped bitumen in SCO scheme *i* [tonne/h]

BF_i = bitumen froth in extraction plant for scheme *i* [tonne froth/h]

BIT_i = bitumen rate via SAGD for SCO production in scheme *i* [tonne/h]

CCH_j = amount of CO_2 captured in hydrogen plant *j* [tonne /h]

CCP_m = amount of CO_2 captured in power plant *m* [tonne/h]

CF = objective cost function [$/year]

CO_2B = baseline carbon dioxide emission of the Oil Sands operations [tonne /h]

CTC = annual transportation cost of the CO_2 captured [$/year]

D = total diesel demand [L/h]

$DBIT_i$ = diluted bitumen entering to upgrading in SCO scheme *i* [tonne/h]

DBR = bitumen rate via SAGD for commercialization [bbl/d]

DSH = diesel consumed by the shovels' fleet [L/h]

DT = diesel consumption by the trucks' fleet [L/h]

D_{TC} = total annual cost of diesel [$/year]

FB_i = LC-finer bottom oil fractions in SCO scheme *i* [tonne/h]

F_j = fuel consumed by hydrogen plant *j* [m^3/h]

H_{HC} = hydrogen demand for hydrocracking [tonne/h]

H_{HT} = hydrogen demand for hydrotreatment [tonne/h]

HP_j = hydrogen produced in plant *j* [tonne/h]

H_{TC} = total annual cost of hydrogen production [$/year]

H_U = total hydrogen demand [tonne/h]

HW_{BE} = hot water demand in bitumen extraction plant [tonne/h]

HW_c = hot water demand in conditioning [tonne/h]

HWD = total hot water demand [tonne/h]

HW_H = hot water demand in hydrotransport [tonne/h]

HW_{TC} = annual cost of hot water [$/year]

NGSB = consumption of natural gas in process steam boilers [Nm^3/h]

NGSEB = consumption of natural gas in SAGD steam boilers [Nm^3/h]

OC = Operating condition for energy and oil producers

OMC_j = annual operation and maintenance cost for hydrogen plant *j* [$/year]

OMC_m = annual operation and maintenance cost for power plant *m* [$/year]

OMF_j = operation and maintenance economic factor for hydrogen plant *j* [%]

OMF_m = operation and maintenance economic factor for power plant *m* [%]

OSR_i = mined oil sand rate for SCO production scheme *i* [tonne /h]

P_{BE} = power demand in bitumen extraction plant [kW]

PC_i = power demand in centrifugation for scheme *i* [kW]

PC_j = power demand in hydrogen plant *j* [kWh/tonne H_2]

PCTH = power demand to transport the CO_2 captured in hydrogen plants [kW]

PCTP = power demand to transport the CO_2 captured in power plants [kW]

PD = total power demand [kW]

PF_{TC} = annual cost of process fuel [$/year]

PF_U = total process fuel demand [Nm^3/h]

PF_{UD} = process fuel demand on delayed coking based scheme [Nm^3/h]

PF_{UF} = process fuel demand for scheme including LC-fining and fluid coking [Nm^3/h]

PF_{UL} = process fuel demand in LC-Fining based scheme [Nm^3/h]

PG_j = power co-generated in gasification hydrogen plant *j* [kW]

PG_m = power generated by plant *m* [kW]

P_H = power demand in hydrotransport stage [kW]

PHP = power demand of SMR hydrogen plants [kW]

P_{TC} = total annual cost of power [$/year]

PT_i = power demands to pump tailings to disposal from scheme *i* [kW]

P_U = total electricity demand in upgrading [kW]

P_{UD} = power demand on delayed coking based schemes [kW]

P_{UF} = power demand for scheme including LC-fining and fluid coking [kW]

P_{UL} = power demand in LC-Fining based scheme [kW]

S_{BE} = steam demand in bitumen extraction plant [tonne/h]

S_c = steam demand in conditioning stage [tonne/h]

SD = total process steam demand [tonne/h]

SH_k = number of vehicles of model k used in the shovels' fleet [dimensionless]

SO_i = mined and SAGD bitumen upgraded to SCO produced by scheme i [bbl SCO/d]

SSE = total steam consumption in SAGD extraction [tonne/h]

SSE_{TC} = annual SAGD steam's cost [$/year]

S_{TC} = annual cost of process steam [$/year]

ST_i = slurry in hydrotransport for scheme i [tonne/h]

S_U = steam demand for upgrading [tonne/h]

T_l = number of vehicles of model l used in the truck's fleet [dimensionless]

VTB_i = vacuum topped bitumen in SCO scheme i [tonne/h]

Binary Variables

HC(i) = 1 if i follows hydrocracking upgrading scheme
= 0 otherwise

HPC(j) = 1 if hydrogen plant j capture CO_2
= 0 otherwise

HPG(j) = 1 if hydrogen plant j is type Gasification
= 0 otherwise

HPS(j) = 1 if hydrogen plant j is of type SMR
=0 otherwise

LF_c(i) = 1 if i follows production scheme with conditioning stage
= 0 otherwise

OPS_i = 1 if SCO production scheme i exists in the operation
= 0 otherwise

PPC(m) = 1 if power plant m capture CO_2
= 0 otherwise

$PS_M(i)$ = 1 if *i* follows an integrated Mining/Upgrading SCO production scheme

= 0 otherwise

$PS_s(i)$ = 1 if *i* follows an integrated SAGD/Upgrading SCO production scheme

= 0 otherwise

$UR_D(i)$ = 1 if *i* follows upgrading route R1

= 0 otherwise

$UR_F(i)$ = 1if *i* follows upgrading route R3

= 0 otherwise

$UR_L(i)$ = 1 if *i* follows upgrading route R2

= 0 otherwise

Integer Variables

NSB = number of boilers that produce process steam

NSEB = number of boilers that produce SAGD steam

NHP_j = number of hydrogen plant type *j*

NPP_m = number of power plant type *m*

Indexes

i = SCO production scheme

j = type of hydrogen plant

J = number of hydrogen plant types

k = model of shovel in the fleet

K = number of shovels' models available in the fleet

l = model of truck in the fleet

L = number of trucks' models available in the fleet

m = type of power plant

M = number of power plant types

N = number of SCO production schemes

Model Parameters

DB = SAGD bitumen production scheme [dimensionless]

CD = cost of the diesel [$/L]

CFB = conversion factor for crude bitumen [h·bbl/d/tonne bitumen]

CFW = cost of the boilers feed water [$/tonne]

CO_2E = carbon dioxide emission target [tonne/h]

CPCT = compression power for CO_2 transport [kWh/tonne CO^2/km]

CS = percentage of the boiler's capacity used to generate process steam [%]

DHGO = average density of HGO fraction in hydrotreatment [tonne/m^3]

d_i = distance from the mining site to the extraction plant i [m]

D_k = fuel consumption in shovel model k [L/h]

D_l = diesel consumption in truck model l [L/h]

DLF = average LC-Finer feed density [tonne/bbl]

DLGO = average density of LGO fraction in hydrotreatment [tonne/m^3]

DNT = average density of NT fraction in hydrotreatment [tonne/m^3]

DVTB = vacuum topped bitumen density [tonne/bbl]

EC = energy conversion factor [MJ/GJ]

FC_j = fuel cost for hydrogen plant j [$/GJ]

FC_m = fuel cost m [$/GJ]

FDDC = process fuel requirements for Delayed-Cokers [MJ/bbl]

FDLCF = process fuel requirements in LC-Finers [MJ/bbl]

FHV_j = fuel heating value in hydrogen plant j [MJ/m^3]

HHF = hydrogen requirements in high conversion LC-finers [ft^3/tonne bitumen]

HHGO = hydrogen requirements for HGO in hydrotreatment [ft^3/bbl]

HLF = hydrogen requirements in low conversion LC-finers [ft^3/tonne bitumen]

HLGO = hydrogen requirements for LGO in hydrotreatment [ft^3/bbl]

HNT = hydrogen requirements for naphta in hydrotreatment [ft^3/bbl]

$HPIC_j$ = installed capacity of hydrogen plant j [tonne/h]

$HPIC_m$ = installed capacity of power plant m [kW]

HR_j = heat rate to produce hydrogen in plant j [MJ/tonne H_2]

HR_m = heat rate to produce power in plant m [MJ/kWh]

HVNG = Western Canadian Gas heating value [MJ/m^3]

PCC_m = power capacity cost factor in plant m [$/kW]

PDDC = electricity requirement in delayed coking [kWh/bbl]

PDFC = power requirement in fluid cokers [kWh/bbl]

PDHF = power requirement in low conversion LC-finers [kWh/bbl]

PDLF = power requirement in high conversion LC-finer [kWh/bbl]

PL = pipeline length [Km]

PNG = price of natural gas [$/GJ]

P_{SE} = power requirement in SAGD extraction [kW/tonne bitumen]

SDRU = steam requirement in the DRU [tonne steam/tonne diluted bitumen]

SFCU = steam requirements in the FCU [tonne steam/tonne diluted bitumen]

SFR = steam requirement in bitumen extraction plant [tonne steam/tonne froth]

SOR = steam to oil ratio [tonne steam/tonne bitumen]

$SOSR_c$ = steam to oil sand ratio in conditioning [tonne steam/tonne oil sand]

SPF_i = slurry pumping factor in SCO scheme i [kWh/tonne slurry/m]

SVDU = steam requirement in the VDU [tonne steam/tonne diluted bitumen]

t = annual operating hours [h/year]

TDB = total diluted bitumen production [bbl/d]

TSCO = total SCO production [bbl/d]

UCF = volumetric conversion factor [m^3/bbl]

UCSC = carbon dioxide underground injection cost [$/tonne CO_2]

UCTC = unitary CO_2 transport cost [$/tonne CO_2/Km]

$WOSR_{BE}$ = water to oil sand ratio in bitumen extraction plant [tonne water/tonne oil sand]

$WOSR_C$ = water to oil sand ratio for conditioning [tonne water/tonne oil sand]

$WOSR_H$ = water to oil sand ratio for hydrotransport [tonne water/tonne oil sand]

ρ_{H2} = hydrogen density [ft^3/tonne]

Chapter 1

1 Introduction

1.1 The Oil Sands Industry

The Western Canada Sedimentary Basin (WCSB) is located on parts of Alberta, Saskatchewan, British Columbia, Manitoba and the Northwest territories. The WCSB contains the main oil reserves in Canada. The Oil Sands, located in the province of Alberta, Canada, are the leader oil reserves in the WCSB. As shown in Figure 1-1, the Canadian Oil Sands is the third largest crude oil reserves proven in the world next to Saudi Arabia and Venezuela [1]. Canada is the only non-OPEC country in the top five proven world oil reserves. The Oil Sands reserves accounted 171.3 billion barrels in 2009, approximately 13% and 95% of the world and Canadian oil reserves, respectively [2]. The Oil Sands consists of bitumen, a heavy and viscous crude oil found in the grounds mixed with sand, clay and water. Bitumen can be diluted with solvents, e.g., naphtha, to reduce its viscosity and thus enable its transportation by pipelines.

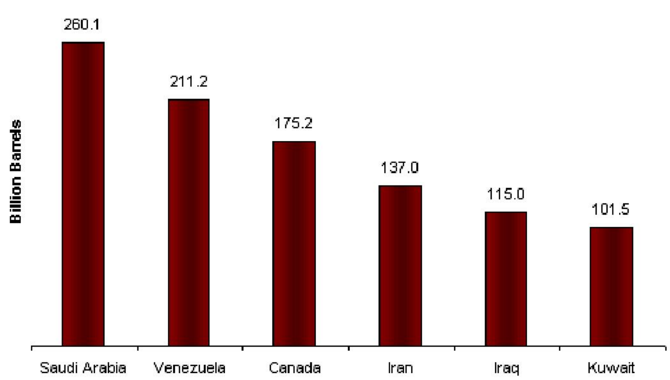

Figure 1-1. Top proven world oil reserves, January 1, 2011 [1]

Crude oil dominates the world's energy supply because its production is economically attractive when compared to other alternatives, e.g., wind energy, solar energy, biofuels. According to the International Energy Agency (IEA) and the US Energy Information Administration (EIA), the world oil demands will reach 120 million barrels daily by 2030. One quarter of this demand will come from Canada and the United States [3, 4]. As the conventional crude oil production keeps declining, the unconventional crude oil sources, e.g., bitumen, will become more attractive and considered as strategic oil reservoirs and potential energy suppliers. According to the government of Alberta, Alberta supplied to the United States about 1.4 million barrels per day, which represents 15% of the U.S. crude oil imports in 2009 [2]. The United States has been the traditional oil market for Canadian oil. However, Asian oil companies have started to invest and develop new Oil Sands projects. These recent new developers are opening the Canadian oil industry to the global energy market, especially the East Asia markets.

Canadian average daily crude oil production was 2.7 million barrels in 2009; about 50% of this production was obtained from oil sands. Since oil is expected to remain as the main source of energy in the world in the medium term future, the Oil Sands industry is expected to increase its crude oil production in the upcoming decades to ensure oil supply for the United States and the rest of the world. Several Oil Sands projects that consider new developments or expansion of the existing operations have been approved or are already under construction [5]. Also, the rebound in oil prices, as a result of the economic recovery that followed the world's economic recession of 2008, has boosted the interest in the Oil Sands operation sector. However, there are uncertain factors related to the future growth of Oil Sands activities due to the availability of energy commodities, i.e., power, hydrogen, steam. Also, environmental limitations regarding long term Greenhouse Gas (GHG) emissions is a key aspect that both the

Alberta provincial government and the Canadian Federal government need to address to sustain the operability and production of the Oil Sands in the upcoming years.

Based on the above, there is a need to develop efficient and robust models that can accurately describe the current and future operation of the Canadian Oil Sands industry. These models can be used as a tool to assess future production scenarios, and their corresponding environmental impact, for this industry. Also, Oil Sands operations models can be used to evaluate the infrastructure needed to meet the oil production demands in the upcoming years. Thus, the proposed models can be used to plan and schedule the future operation of this industry. Accordingly, these models can be used as a making decision tool for the development of new projects for the Oil Sands industry. Moreover, uncertainties in the key variables that have a significant effect on the Oil Sands operations can be evaluated using these modeling tools, e.g., natural gas prices, CO_2 emissions targets and steam to oil ratio (SOR) for the crude bitumen in-situ extraction methods. These uncertainty production factors can be incorporated by considering worst-case, expected and optimistic scenarios for the Oil Sand operations in the future. These analyses will provide a broader scope of the future operation of this industry and the potential (environmental) consequences associated with these activities. Thus, new provisory measures or regulations can be promoted or developed to account for the effect of uncertainty on these parameters on the Oil Sands operations.

Mathematical models that describe the Oil Sands operations have been recently reported in the literature [6-8]. Although those models have provided insight regarding the future scenarios expected for this industry, the proposed mathematical models only provide limited information about the operations of this industry since they have only focused on the infrastructure that may be needed for the energy producers. That is, the models currently proposed in the literature to describe the Oil Sands operation assumed that the oil production schemes (and their corresponding capacities) are known with certainty and they are considered as inputs (fixed) parameters to the models. Thus, the present models have not included within the formulation the simultaneous selection of both the energy commodities' infrastructure and the oil production schemes that minimize the operation costs for this industry in the presence of environmental (CO_2) constraints. Therefore, a modeling tool that integrates the Oil Sands producers and energy producers in a single formulation has not been proposed in the literature.

1.2 Research objectives

The aim of this research is to develop a comprehensive integrated energy optimization model that can be used to describe the current and future operation of the Oil Sands industry. The model will consider the following features:

1) The energy producers and the production schemes are explicitly considered in the model's formulation. That is, the energy optimization model will simultaneously provide with the optimal energy producers and oil production infrastructures that minimize the costs of the Oil Sands operations.
2) The energy producers considered in this work are the plants used for the generation of the energy commodities, e.g., steam and hot water produced in natural gas boilers, electricity in power plants, and hydrogen.
3) The production schemes for bitumen and synthetic crude oil (SCO) producers includes different combinations of bitumen extractions methods and upgrading technologies, e.g., Mining and Steam Assisted Gravity Drainage (SAGD) as extraction methods, Delayed Coking (DC), LC-Fining (LCF), and LC-Fining plus Fluid Coking (FC) as the upgrading technologies.

4) The integrated model will determine the CO_2 emissions generated by the Oil Sands operations. This information will be useful to plan and schedule future energy producers and oil production infrastructure that may be developed for this industry.
5) Following the previous item, the model includes an environmental constraint that can be used to study the future configurations that may be needed to run the Oil Sands operations under a CO_2 emission target.

The present study will also analyze the advantages of using an integrated energy model for the Oil Sands operations, which considers both the energy and oil producers in the model's formulation, over previous models that did not consider this integrated scheme. Historical data and information listed in previous reports is used in this work to validate the energy optimization model. Also, the integrated model is used to determine the Oil Sands operations for future scenarios under different (environmental) conditions.

1.3 Research outcomes

To the authors' knowledge, the integrated energy model developed in this work is the first that simultaneously solves for both bitumen and SCO production schemes and its corresponding energy producers' infrastructure at a minimum cost with a CO_2 emission constraint for the Canadian Oil Sands operations. That is, the results of this project quantify the energy costs of producing SCO and diluted crude bitumen, the most suitable configuration of SCO production schemes and energy plants. Also, it determines the financial penalty that must be paid when considering reduction in the levels of GHG emission. Therefore, the model can be used by Oil Sands developers to estimate the contributions of different economic factors involved in the calculation of the total energy supply costs for the operations, i.e., power, hydrogen, steam and hot water production costs, process fuel cost, energy producers capital cost, operations and maintenance costs. This result can be used to determine the rate of returns based on process costs estimations. Also, the energy demands and GHG emissions can be estimated according to the expected growth of the oil industry in the province of Alberta, Canada. This information can then be used to plan and schedule new energy facilities for the sustainable growth of this industry in the province of Alberta. Moreover, the integrated energy model can also be used to study the inherent characteristics of the different oil production schemes, i.e., process fuel, hydrogen, electricity and steam consumption rates per barrel of oil produced. Furthermore, the influence of the key process parameters over the operation can be evaluated with the model, e.g., natural gas prices, steam to oil ratio (SOR), and GHG emissions. Accordingly, economic analyses can be carried out to determine the impact of introducing CO_2 carbon capture and storage technologies within the Oil Sands industry.

1.4 Organization of the Research project

This thesis is organized as follows:

Oil Sands Operations – Chapter 2. This section presents an overview of the Oil Sands sector, the oil producers (energy commodity demanders) and the energy producers (energy suppliers) involved in the Oil Sands operations. A review on the models currently available to study the Oil Sands operations are also discussed on this section.

Oil Sands Operations Model – Chapter 3. This section presents the details of the integrated energy optimization modeling tool developed in this work. The model inputs and the environmental constraint (CO_2 emission target) considered in the model are presented first. This is followed by the description of the mathematical models used to represent the energy producers and oil production schemes available for the Oil Sands operations. The optimization formulation developed to determine the energy fleet's costs for the Oil Sands operations is presented next. The challenges involved to solve such optimization problem are discussed at the end of this section.

Results and Discussion – Chapter 4. This section presents first a case study for year 2003 that was used for model validation. Comparisons between the results obtained by the present integrated model and those reported by other studies and sources in the open literature are presented in this section. Also, a case study that determines the Canadian Oil Sands operation for 2020 is presented. The integrated model is used to determine the most suitable combination of production schemes and energy producers with and without a CO_2 emission target. Due to uncertainties in the bitumen and SCO productions for 2020, the integrated model was solved for different scenarios corresponding to the highest, lowest and reference oil production forecasts for 2020.The results obtained from that sensitivity analysis are discussed at the end of this section.

Conclusions – Chapter 5. Concluding remarks and future work that may be conducted on this research are presented on this section.

Chapter 2

2 The Oil Sands Operations

This chapter presents an overview of the Oil Sands sector, the expected growth of this type of oil industry in Alberta, and the main exploration and crude bitumen extraction methods used by the operators. The synthetic crude oil (SCO) and crude bitumen producers (energy demanders) are discussed in detail. Also, the technologies commonly used by the energy commodity producers included in the present model are discussed in detail, i.e., boilers, power and hydrogen plants included in the model. Also a review of current models describing the Oil Sands operations are discussed at the end of this chapter. It is important to understand the processes involved in the Oil Sands industry because they enable to determine the main modeling elements that need to be addressed to represent the industry operations, which is the aim of this research. The description of the oil producer stages allow to determine the mass and energy balances involved in each processing stage. The mathematical formulation of these balances results in the construction of the oil production scheme models. Similarly, a discussion of the energy producer technologies will introduce the energy and mass balances that are involved in each energy plant. Once these factors are well understood, the energy commodity production costs can be mathematically represented to determine the annual energy costs of the Oil Sands operations, which is the main objective of this mathematical model used to evaluate the Oil Sands industry.

2.1 The Oil Sands Sector

This section presents an overview of the main activities and processes considered in the Oil Sands sector, e.g., oil exploration, extraction and refining. Also, the locations of the Canadian oil reservoirs and the expected growth of Oil Sands activities in the medium term future are illustrated on this section. Moreover, the GHG emissions challenges that will face the industry due to environmental regulations are also discussed along with CO_2 reduction technologies.

2.1.1 Exploration and Extraction

Canada holds oil reserves in the Alberta Oil Sands, the conventional oil deposits in the WCSB, off-shore oil fields in the Atlantic, under the Beaufort Sea in the Arctic, off the Pacific coast, and in the Gulf of St. Lawrence. The current Canadian oil production comes from the first three sources mentioned above. However, the Alberta Oil Sands is the main oil source and most promising energy source of Canada since most of the on-shore and off-shore fields are reaching their maturity. However, the Canadian oil production is projected to keep growing in the upcoming years. Also, it is expected that the domestic petroleum consumption will remain approximately constant in the upcoming years. According to the EIA, the average petroleum consumption growth rate through 2035 is estimated to be 0.1% in Canada [1]. Therefore, Canada will have an increasing oil surplus throughout this period of time that will be used for exports (see Figure 2-1). Hence Canada will be considered as one of the main non-OPEC oil producers in the medium to long term.

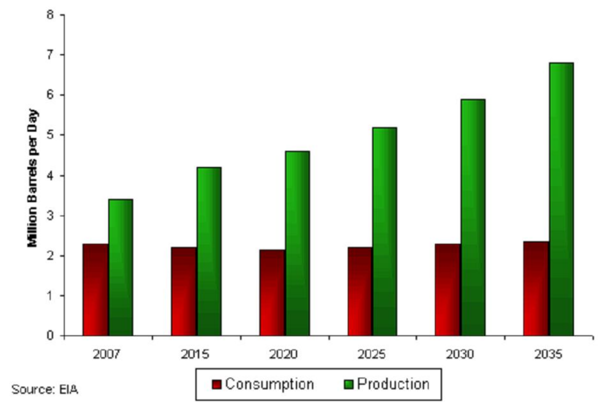

Figure 2-1. Canada's oil balance forecast, 2007-2035 [1]

Most of the Canadian crude oil is produced in the western provinces (WCSB) and approximately 11% of the crude oil is produced in Atlantic Canada [9]. The Oil Sands production represents 58% of western Canada's crude oil production. As shown in Figure 2-2, the Oil Sands reserves are located in three regions in northern Alberta: the Athabasca, Cold Lake, and Peace River.

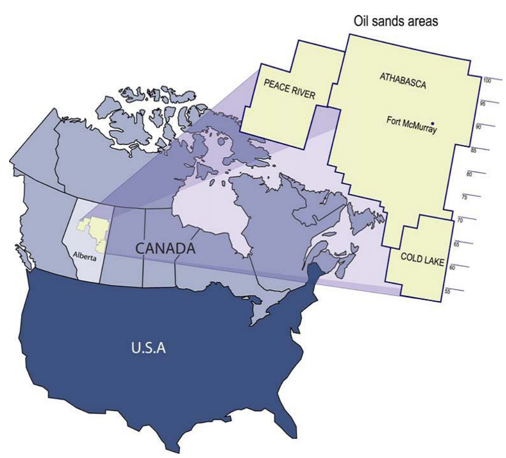

Figure 2-2. Oil Sands regions in Alberta [10]

The present technological development in the oil industry allows the recovery of approximately 171.3 billion barrels of oil from the Oil Sands reservoirs (315 billion barrels). Nearly 80% of the Oil Sands can be recovered by in-situ extraction methods and the remaining 20% through mining. The percentage of bitumen recovered depends on the extraction method employed. Mining recovers 90% of the bitumen whereas in-situ methods such as cyclic steam stimulation recover 35-40% and steam assisted gravity drainage recover 50-60% of the bitumen, respectively [2]. In-situ extraction methods are used for bitumen deposits located more than 75 m underneath the surface. Most of the deposits recovered by this method are located 350-600 m beneath the surface. In the in-situ extraction method, the bitumen in the sand is treated with steam, solvents or thermal energy that will enable the bitumen to flow and be pumped to the surface. One of the advantages of using in-situ methods is that they do not produced tailings ponds, which are deposits where the residues of mining extraction, i.e., water, clay, sand and residual bitumen are kept. The tailings are usually placed on discontinued mine pits and have a significant impact on the landscape. The Cold Lake region is home to the current largest in-situ project in Canada. The project employs steam assisted gravity drainage (SAGD) which consists of steam injection into the underground reservoir to extract the bitumen to the surface.

Mining extraction is used for bitumen deposits up to 75 m depth. Electric and hydraulic shovels, nominal capacity of 45 m^3, are used to mine the Oil Sands deposits whereas trucks that can carry up to 400 tonnes of ore are employed to transport the oil sand to processing units where hot water and diluents (naphthanic, parafanic) are added to the oil mixture to separate the bitumen from the sand. The tailings are separated from the crude bitumen and sent to the tailings ponds whereas the diluted bitumen is pumped to upgrading facilities located either in Alberta or the United States. Only 500 km^2 out of the available 140,000 km^2 of oil sands are currently used for mining extraction [2].

2.1.2 Bitumen Upgrading and Refining

Bitumen can be sold as diluted bitumen or upgraded crude bitumen. Upgraded bitumen is obtained via Integrated SAGD/Upgrading or Mining/Upgrading production schemes through hydrocracking or thermocracking processes. These cracking processes yield a light and sweet Synthetic Crude Oil (SCO). According to [11], it is expected that the production of bitumen will reach 3 million barrels by year 2020. Figure 2-3 illustrates the steps in the upgrading process. In primary upgrading, thermocracking (coking), hydrocracking or a combination of both cracking technologies is used to decompose the large hydrocarbon molecules into lighter compounds, i.e., naphtha, light gas oil (LGO), and heavy gas oil (HGO). While the coking process aims to remove the carbon (coke) from the bitumen, thus decomposing the large hydrocarbon chains into smaller compounds, hydrocracking adds hydrogen to the bitumen, thus fragmenting the heavy hydrocarbon compounds. In the secondary upgrading stage, the lighter hydrocarbon molecules are treated with hydrogen and a solid catalyst (hydrotreatment) to remove oil impurities such as sulphur and nitrogen.

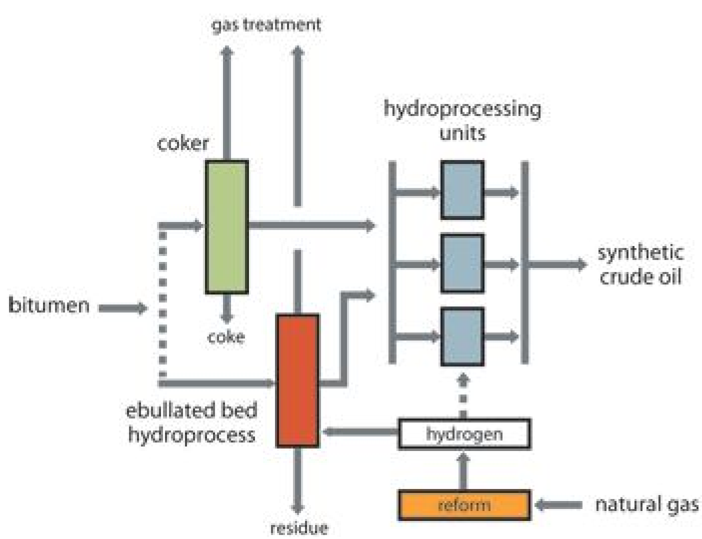

Figure 2-3. Bitumen Upgrading process to SCO [12]

The sweet products from upgrading, i.e., the SCO, is sent to refineries where the upgraded crude oil is converted into products, e.g., gasoline, diesel, jet fuel, kerosene, butane and other hydrocarbons of commercial interest. Most of the diluted crude bitumen and SCO produced in Canada is sold to refineries located in the Gulf Coast (Louisiana and Texas), California, the Midwest and New England. Also, part of the Canadian crude production is sold to three Canadian refinery hubs: Southern Ontario, Quebec and New Brunswick. The government of Alberta is encouraging the construction of new refinery facilities in the province in order to boost the local economy by producing added value products [2].Thus, a portion of the crude is refined in Alberta and sold locally to promote the province's economic activity.

The economic incentive for the production of SCO (upgraded crude bitumen) instead of diluted crude bitumen is given by the light-heavy differential, which is the difference in economic value between diluted crude bitumen and SCO. The production costs for current new upgrading facilities are in the range of $10-15 per barrel [12]. However, the final costs are directly proportional to the plant's capacity (economy of scale). Generally, upgrading requires large scale production to be economically feasible, but the integration of bitumen extraction and recovery plants is becoming an economically attractive method for the production of SCO. A plant with a production capacity of 100,000 barrels of SCO per day is considered as the minimum capacity for an acceptable economic return in the oil industry. The current trend in the oil industry is to integrate upgrading and refining. The first project in the Oil Sands that integrated upgrading and refining is the Shell Scotford in 1984; however, Petro-Canada is also considering this new operation scheme [12].

The upgrading processes will face some challenges in the midterm future. One of these challenges is associated with the construction costs. This mainly depends on the availability of a qualifying labor force, which is a major concern in Alberta, and the development of new projects in remote locations, which increases the capital costs. Natural gas has been traditionally used in the Oil Sands industry for the production of hydrogen and as a process fuel given its relative low cost in western Canada. However, the natural gas prices have increased in the last few years. This trend is expected to hold since natural gas is one of the least GHG emission fossil fuels available in the market. Thus, natural gas is an attractive fuel that can replace other fossil fuels, e.g. coal, as a consequence of the climate change issues and new environmental state policies. The development of new upgrading technologies has been dominated by the United States and Europe. Nevertheless, the Canada Centre for Mineral and Energy Technology (CANMET) and the Alberta Research council have made attempts to develop their own technology for bitumen upgrading. Recent financial interest of investor for developing new projects in the Oil Sands will also promote the technological developing of the upgrading technologies for this industry.

2.1.3 Greenhouse Gas (GHG) emissions

Several gaseous emissions may have a noxious effect on the environment and contribute to climate change. Climate is the average weather in a specific geographic region for certain period of time (~30years). Thus, climate change is the long term shift of the weather measurable parameters, e.g., temperature, precipitation, wind. Climate change implies the shift in conditions for an extended period of time that can be due to natural causes or induced by human's activities. However, in a political context, the term *climate change* commonly refers to human induced weather shift as introduced in the United Nations Framework Convention on Climate Change [13]. This framework established the foundations to stabilize GHG concentrations in the atmosphere at a level that would prevent risky human interference with the climate system. The framework established that the GHG levels need to be achieved within a time period such that the ecosystems can adapt naturally to climate change. This would allow social and economic development in a sustainable fashion [14]. On the other hand, the term *global warming* refers to a sustained increase in the average of the global surface temperature, which corresponds to one of the many parameters that are used to measure climate change. As global warming implies an average increase in the global temperature, there could be regions experiencing cooler temperatures than normal. The increase in the average global temperature is accompanied by shifts in other climatological parameters such as wind and precipitation, which also modifies weather patterns around the globe. For this reason, the term *global warming* is commonly used interchangeably with the term *climate change*. However, the term *climate change* is more appropriate to be used when describing shift in the climate system.

The current trend in which human activities are being conducted in the world such as energy production, energy consumption and industrial manufacturing processes are producing both air pollutants and GHG. Some of the substances classified as air pollutants occur naturally on earth since they are produced from a variety of natural sources such as forest fires, soil erosion, volcanoes and dust storms. These substances may have contributed to determine the current conditions of the earth. Nonetheless, the addition of new sources of pollutants through human activities can significantly impact natural life processes on earth. The air pollutants can be divided in four categories: criteria air contaminants, persistent organic pollutants, heavy metals and toxics [13]. These air pollutants are present in smog, acid rain and transboundary air, which affect human health and the natural ecosystems, i.e., soil, water, vegetation and wildlife. The impacts of air pollution can be experienced not only where the sources are geographically located, but also at far distances from the sources (different country) since pollutants can travel long distances through the air.

Similarly, the greenhouse gas (GHG) effect consists on creating warmer conditions on earth than those that would naturally exist. This effect is caused when the atmosphere acts like the glass in a greenhouse. In a greenhouse, energy from the sun passes through a glass as ray of light to create warmer conditions that allow plants to grow during cold outdoor seasons. The glass prevents the warmed air from escaping thus helping to keep the greenhouse warm [13]. Likewise, the GHG components of the atmosphere absorb and keep some of the infrared radiations (heat energy), coming from the sun inside the earth's atmosphere, which insulates the earth and prevents the heat from being radiated back into space causing the increment of the surface temperature. The GHG components, which generate the greenhouse effect, can be produced naturally or anthropogenically (human induced). Without the natural GHG effect, the surface temperature would be approximately -18 ºC instead of the current average temperature of 15 ºC. The current temperature condition allows the cycling of water through the land, ocean and atmosphere that provides the necessary water to sustain life on earth. Also, this cycle represents a main driver of the planet's weather and the climate system in general. However, human made GHG are accelerating the natural greenhouse effect process forbidding the ecosystems to naturally adapt to the new conditions, which creates unbalances in the ecosystems that affects the climate system [13].

The main gaseous emissions of concern for the Oil Sands industry are represented by carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Each gaseous emission has a different global warming impact per unit basis, i.e., methane has a global warming impact of 23 relative to carbon dioxide (1) [12]. However, carbon dioxide accounts for 85-95% of the total enhanced global warming effect [12]. The province of Alberta became the first administration to enact laws for reducing GHG emission for large industrial operations in North America [2]. Nevertheless, the increase of Oil Sands operations has also generated the increase of carbon dioxide (CO_2) emissions in the province of Alberta. The total GHG emission in Alberta for 2008 was 110.9 megatonne of CO_2 equivalent (Mt of CO_2e), the Oil Sands industry accounted for 31.4% of the emissions (second largest), the utilities sector was the largest source of GHG emissions in Alberta with 44.1 % or 48.9 Mt of CO_2e [2]. From the total Oil Sands' GHG emissions, mining and upgrading represented 21.5% whereas in-situ operations represented 9.9%, respectively [2]. According to Industry Canada, the average GHG emission is 40 kg of CO_2e per barrel in mining bitumen recovery, and 60 kg of CO_2e per barrel for in-situ operations [12]. The two previous bitumen recovery processes considered natural gas as the only feedstock fuel for the operations. Burning other fossil fuels, i.e., residue fuels, coke and coal for power and hydrogen generation will generate higher GHG emission unless CO_2 capture and sequestration technologies are implemented on the Oil Sands processes.

Figure 2-4 shows the expected CO_2e emission in Alberta. The Alberta government alternative plan to the Kyoto protocol is known as *Turning the Corner*, a regulatory framework for industrial GHG emissions [15]. This plan requires the improvement of emissions intensity that will lead to significant GHG emission reductions by 2020. The framework also stipulates carbon capture and storage strategies with expected GHG emission reductions of 50 Mt of CO_2e by 2020 in Oil Sands operations compared to the current emission trend level. Following the federal Regulatory Framework, which regulates GHG emissions in the new in-situ and upgrader facilities coming on stream in 2012 or later, the total GHG emissions should be reduced by 60 Mt of CO_2e by 2020. Thus the total GHG emission to the atmosphere expected for 2020 should be at the levels of 50 Mt of CO_2e (see Figure 2-4).

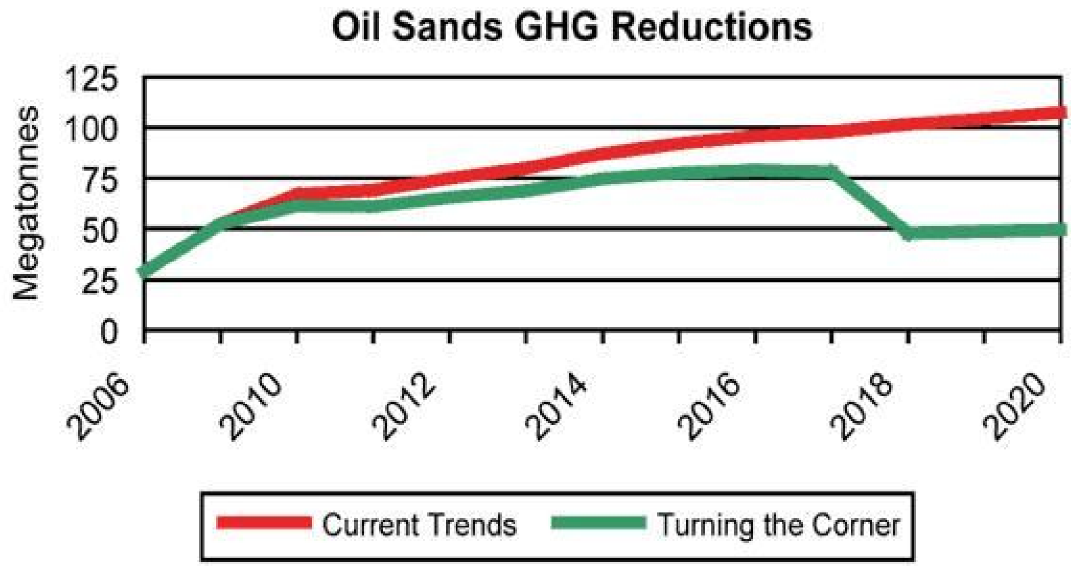

Figure 2-4. Oil Sands industry CO_2e projections [15]

Carbon capture and storage (CCS) systems consist on separating and capturing the CO_2 from an industrial process or exhaust gas emissions before they are vented to the atmosphere. This is a mean to mitigate GHG, especially carbon dioxide (CO_2) to palliate climate change. The term also applies to the scrubbing of CO_2 from ambient air. Carbon capture can be applied on large emission sources such as fossil fuel energy facilities, natural gas processing facilities, synthetic fuel plants and fossil fuel hydrogen plants. Currently, there are three main carbon capture methods available: pre-combustion, post-combustion and oxyfuel combustion. The selection of the type of carbon capture system to be used depends mainly on the concentration of CO_2 in the gas stream, the pressure of the gas stream and the type of fossil (solid or gas). Accordingly, in pre-combustion capture the CO_2 is removed before the combustion of the fuel. This process can be used in chemical, fertilizer and power production plants since the fossil fuel can be partially oxidized and the resulting syngas (i.e., carbon monoxide) and water vapour) can be shifted into CO_2 and H_2, respectively. Therefore, the relatively pure exhaust stream of CO_2 can be captured and the H_2 used as fuel. However, the initial step where the fuel is converted into CO_2 and H_2 is more complex and expensive than other methods, i.e., post-combustion, the higher concentration of CO_2 and the pressure of the gas stream in pre-combustion makes easier the separation of the CO_2 from the stream. On the other hand, in post-combustion capture the CO_2 is removed after the combustion of the fuel. This technology is commonly applied to power plants that burn fossil fuels by capturing the CO_2 coming from the flue gases. This technology is economically feasible under specific conditions such as a favorable tax regime or a niche market. However, in oxyfuel combustion capture, the CO_2 is removed from the stream of flue gases (CO_2 and H_2O) from the combustion process after the stream is cooled and the water condenses. Thus, the resulting high purity stream of CO_2 is ideal for CCS purposes. The flue gases coming from oxyfuel plants have a higher concentration of CO_2 compared to other combustion processes, since the fossil fuel is burned in the presence of pure oxygen. Typically, oxyfuel plants are used to produce electricity. It is easier to separate the CO_2 from the flue gas stream due to its high purity in oxyfuel combustion. However, large energy requirements (energy costs) are usually involved in the separation of oxygen from air to obtain the pure oxygen employed in the combustion process [16].

After the CO_2 is captured, it has to be transported to suitable storage sites, e.g., geological formations, aquifers or minerals. The transportation process is accomplished by compressing the CO_2 via pipeline since this is currently the most economical form of transport. Transporting CO_2 is analogous to shipping liquefied petroleum gases. Also, CO_2 can be carried by rail and road tankers but this method is not effective for large scale transportation. After transportation, the CO_2 can be stored in geological formations (geological storage) where the carbon dioxide is injected into underground formations such as depleted oil fields, gas fields, saline formations or unmineable coal seams. However, aquifer storage involves injecting the CO_2 into aquifers that are wet underground layer of water bearing permeable rock materials. On the other hand, in mineral storage the CO_2 is induced to react with metal oxides to produce stable carbonates. However, CCS technologies require significant amounts of energy which increases the costs associated to energy production. For example, a power plant equipped with a CCS system would increase its average energy requirements by 10-40% [16]. Most of the energy increase would be used to capture and compress the CO_2 reducing the emissions to the atmosphere by approximately 80-90% compared to a plant with equivalent output without CCS technology. Moreover, the cost range of carbon capturing applied to coal or gas fired power plants goes from 15-75 US$/tonne CO_2 and when applied to hydrogen or gas processing plants the cost ranges 5-55 US$/tonne CO_2. Additionally, the transportation costs ranges 1-8 US$/tonne CO_2 and the geological storage costs 0.5-8 US$/tonne CO_2 [16].

Carbon dioxide sequestration is the most promising technology to reduce GHG emissions in the medium and long term. Other applications consider the use of captured CO_2 for enhanced oil recovery (EOR), coal bed methane production (CBM) and to repressure oil reservoir. The Western Canada Sedimentary Basin has large areas suitable for CO_2 storage. However, monitoring activities should be carried on after the underground injection to ensure that the gas emissions are not vented into the atmosphere. It is estimated that the total space available for CO_2 storage in the Oil Sands could last for more than 300 years at a rate of 100 megatonne per year [15]. This technology is cost effective provided that it involves large amounts of carbon dioxide, i.e., gas emissions produced at Oil Sands operations, hydrogen and electricity plants. However, more research is necessary to reduce the sequestration costs as well as the development of an adequate pipeline grid to transport the CO_2 captured.

Another approach considered to reduce GHG emission involves the use of co-generation plants. Co-generation is based on the simultaneous generation of multiple useful energy sources, i.e., power, hydrogen, heat, refrigeration/cooling, water recycling, evaporation and drying [17]. Thus, two energy commodities can be produced simultaneously from the same fuel source. This allows the production of the energy commodities at lower GHG emissions when compared to the independent production of each commodity. The industry uses this type of system to improve energy efficiency and reduce GHG emissions. Thus, they can collect carbon credits that can be traded to earn revenues. Co-generation also can reduce water consumption and its associated costs. Recently, Oil Sands developers have introduced co-generation systems into their operations for the production of power and thermal energy from the same source, i.e., gas turbines with heat recovery steam generators. Currently, these systems are most suitable for mining and upgrading operations. To produce sufficient steam for in-situ operations, considerable amounts of extra power needs to be produced and the existing electricity grid is not ready to handle this excess in power [9]. The use of co-generation facilities can be extended to the simultaneous production of hydrogen and power for Oil Sands operations. Also, co-generation systems can be integrated with carbon capture and storage technologies to further decrease GHG emissions, thus they can act as complementary technologies.

Also, nuclear energy has great potential for the production of hydrogen with almost free GHG emissions. Most of these technologies split water molecules to produce hydrogen (H_2) by the application of thermal or electrical energy. The decomposition of water molecules requires large amounts of energy, i.e., 123 MJ per Kg of hydrogen produced [18]. The most promising methods to produce hydrogen at large scale are based on thermochemical and electrolytic processes. Thermochemical cycles use a series of chemical reactions to decompose the water molecule producing hydrogen (H_2) and oxygen (O_2). This technology uses thermal energy (heat) to drive the endothermic reactions involved in the process; the reactions are generated at a temperature range of 750-1000 ºC. Thermochemical cycles have great potential for hydrogen production because they can work at high efficiency rates and be easily scaled to large capacities. On the other hand, electrolysis currently represents one of the most common methods used for hydrogen production directly from water. The process consists of the decomposition of water into hydrogen (H_2) and oxygen (O_2) by the action of an electric current that passes through a body of water. However, thermochemical cycles is regarded as having better potential at achieving lower hydrogen production costs compared to conventional electrolysis. This is because electrolysis requires the conversion of heat to electricity before the hydrogen is produced, whereas thermochemical cycles produces hydrogen directly from thermal energy [18].

2.2 Production Schemes

The integrated model considers surface methods and in-situ methods for crude bitumen extraction. The surface method requires mining the oil sand whereas the in-situ method involves injecting an external agent into the underground reservoir. SAGD extraction is the only in-situ method considered in this study for diluted bitumen production. This is because SAGD extraction is expected to become the leading bitumen extraction method in the medium term future [2]. Also, the crude bitumen product from SAGD extraction can be directly sold to markets whereas mined bitumen is typically upgraded to SCO on-site before its commercialization. The crude bitumen product from mining contains relative high proportions of water and solids that makes it unsuitable for most refineries. On the other hand, when studying SCO production both extraction methods are considered: mining and SAGD. This is because mining has been the traditional method to produce SCO in the Oil Sands whereas SAGD is projected to become the most important extraction technology in the medium term future [2]. Three different oil products are considered in the model’s formulation: mined bitumen upgraded to SCO (integrated Mining/Upgrading production schemes), SAGD bitumen upgraded to SCO (integrated SAGD/Upgrading production schemes) and SAGD diluted bitumen. These products and their corresponding production schemes are shown in Figure 2-5. Mining and SAGD bitumen upgraded to SCO are the production schemes modeled to produce SCO. The bitumen upgrading technologies considered in this study are the leading technologies currently used in the Athabasca region [19] (see Figure 2-8). The three oil production methods considered in the present study are shown in Figure 2.5. The stages involved in crude bitumen and SCO production are described next.

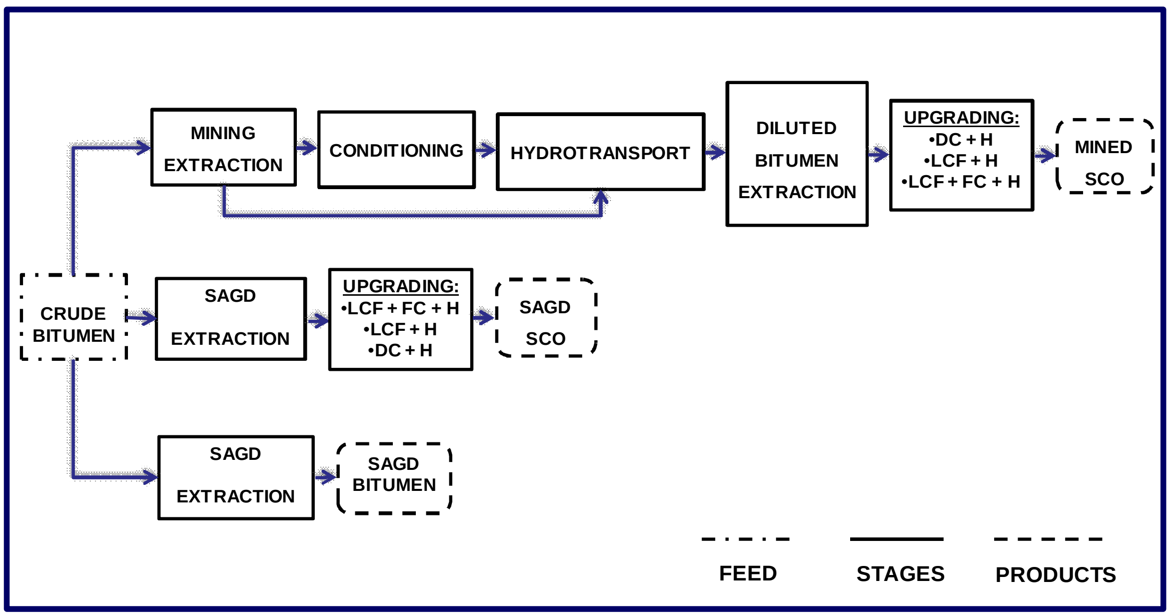

Figure 2-5. Bitumen and SCO production schemes

2.2.1 Crude bitumen extraction methods

Mining and SAGD are the main technologies currently used by Oil Sands operators to recover the bitumen trapped in the sand. These extraction processes are expected to remain as the leader technologies in the Oil Sands industry.

• **Surface Mining Extraction:** This method is based on traditional pit mining for extracting heavy oil deposits within 75 m from the surface. Oil Sands mining methods can be divided in conventional and modern methods. In the conventional mining method the sand is directly transported to the bitumen extraction plant using walking dragline/reclaimers or shovels/trucks. Conventional mining, which was developed in the 1950's, is rarely used in the current Oil sands operations since it has been almost replaced by modern mining. Modern mining was developed in the 1980's and it uses shovels/trucks to transport the mined oil sand to crushers to reduce the size of the ore. A mixer combines the oil sand with hot water, then the resulting slurry is transported via pipeline to the bitumen extraction plant.

Modern mining includes several stages: first the trees are cleared from the forest; then, the overburden materials, which are composed of sand, gravel and shale covering the Oil Sands, are removed to create a suitable surface for mining operations. Shovels are used next to mine the oil sand deposits while trucks transport the sand to crushers to reduce the size of the mined materials. The oil sand is then mixed with water to produce slurry and enable its transportation using centrifugal pumps and pipelines (hydrotransport process) to the bitumen extraction plant where the crude bitumen is separated from the sand, clay and water. The process tailings are sent to sedimentation ponds since there is a zero discharge policy applied to Oil Sands operators, i.e., the operators have to store all process water and tailings on site [20]. This extraction technology currently has a recovery rate of 97% of the bitumen contained in the sand. However, this method heavily depends on the quality of the deposit [12]. Figure 2-6 shows a typical diagram of surface mining operations.

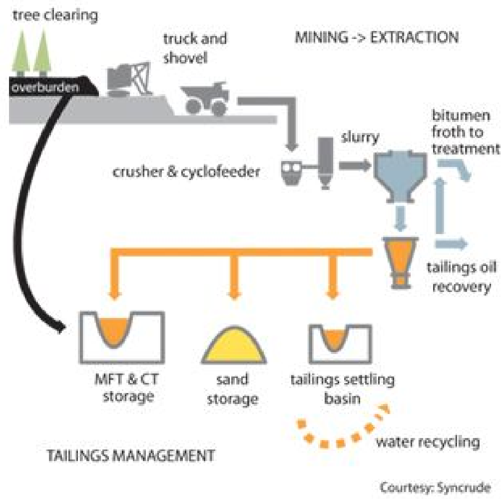

Figure 2-6. Process steps involved in mining operations [12]

• **In-situ Extraction:** This method is used in bitumen deposits deeper than 75 m from the surface. At this depth, mining is not a practical extraction method. The technological development reached in horizontal drilling was the starting point to SAGD extraction. SAGD is the main in-situ method employed in the Oil Sand industry. This method has the potential to allow bitumen extraction from thinners oil reserves. The performance of this method (SAGD) is based on the permeability of the reservoir, i.e., this method consist of steam underground injection that heats the heavy oil in the sand and enables the recovery of the crude bitumen. The higher the permeability, the lower the injection pressure and steam to oil ratio (SOR) necessary to extract the oil from the reservoir.

In typical SAGD operations several horizontal well pairs are drilled from the same pad extending as long as 1,000 meters horizontally into the oil sands and about 5 meters apart vertically [12]. The steam is injected through the top well to heat the oil and thus allows the mobility of the crude bitumen which is produced by the lower well (see Figure 2-7). SAGD offers the advantage that it does not require the development of vast projects, i.e., less financial risks; and the landscaping effects are minimum [12]. Although mining is currently the leading extraction method employed in the Oil Sands, in-situ methods, especially SAGD, are expected to become the leading technologies in the industry. The main reason is that most of the bitumen reservoirs (over 80%) are contained beyond 75 m of depth. The Figure 2-7 shows the typical diagram of the SAGD extraction method.

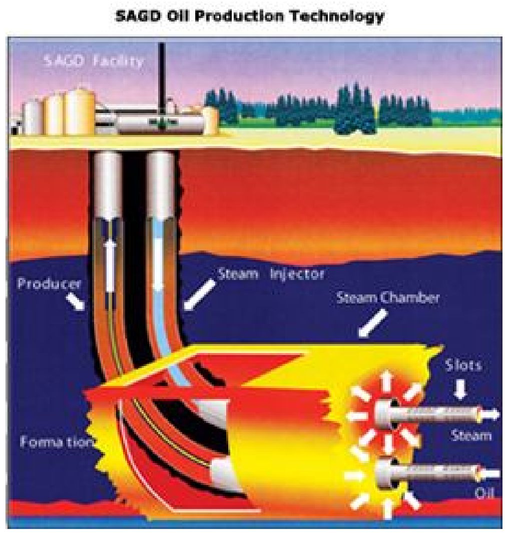

Figure 2-7. In-situ recovery process [12]

2.2.2 Bitumen preparation: Conditioning and Hydrotransport

This stage represents the first process where crude bitumen is separated from the solids materials contained in the oil sands, i.e., quartz sand and clays. This is achieved by the addition of hot water, which creates a film that separates the bitumen from the solids. This process is also used to bring the mixture to a specified state (pH around 8.5) that promotes the separation of the crude bitumen. While conditioning is used in conventional mining production schemes, hydrotransport is mainly employed in modern mining operations. Conditioning mixes the oil sand with process steam, hot water (with a temperature greater than 35 ºC) and caustic soda to produce slurry that is agitated in rotary drums called tumblers. This process takes placed in the extraction plant and it is highly energy intensive. On the other hand, the hydrotransport process adds hot water and caustic soda to the mined oil sand to form slurry that is then pumped via pipeline to the bitumen extraction plant. Unlike conditioning, hydrotransport is a more energy efficient process.

2.2.3 Bitumen Extraction Plant

In this stage the slurry is fed to a gravity settling vessel, known as primary separation vessel (PSV), where the aerated crude bitumen travels to the surface creating bitumen froth. To avoid the formation of solids particles, a stream is recovered from the middle of the PSV. This stream, named middlings, contains small solid particles and traces of crude bitumen that are not able to reach the surface. The PSV bottoms, known as primary tailings, are composed by granulated solids and residual bitumen and are mixed with the middlings for further processing in tailing oil recovery units and flotation cells [21].

The froth coming from the PSV and flotation cells are mixed together resulting in a slurry composed of bitumen (60%), water (30%) and solids particles (10%) [22]. The froth is treated to remove the solids and water using centrifuges and inclined plate settlers. Light solvents such as naphtha are required for froth treatment to reduce the density and viscosity of the oil phase and improve the separation of the solids particle and water from the bitumen. After froth treatment, the oil product contains around 2% of water and 0.4% of fine solids and is ready for bitumen upgrading [23]. The oil product's composition obtained via mining extraction makes unsuitable its transportation and direct sale to the open market for refineries [12]. This is one of the shortcomings of the surface mining sector in the Oil Sands industry. The process bottom streams, commonly known as tailings, are sent to tailing ponds where the solids settles. The tailings are mostly composed of solids and water but they also contain about 2% of emulsified bitumen. Bitumen extraction is highly sensitive to certain process variables such as, temperature and the ore's grade.

In bitumen preparation and bitumen extraction about 6-8% of the sand's bitumen content cannot be recuperated and remains in the process tailings. Due to the use of thermal energy, i.e., hot water and process steam, these two processes represent approximately 40% of the total energy required in the production of SCO [12].

2.2.4 Upgrading

In this stage the crude bitumen obtained from the bitumen extraction plant is upgraded to SCO, which is a product sold to refineries. The upgrading process can follow different routes (R) depending on the technology used for upgrading, i.e., thermocracking or hydrocracking. Figure 2-8 illustrates the stages considered for upgrading according to the technology employed.

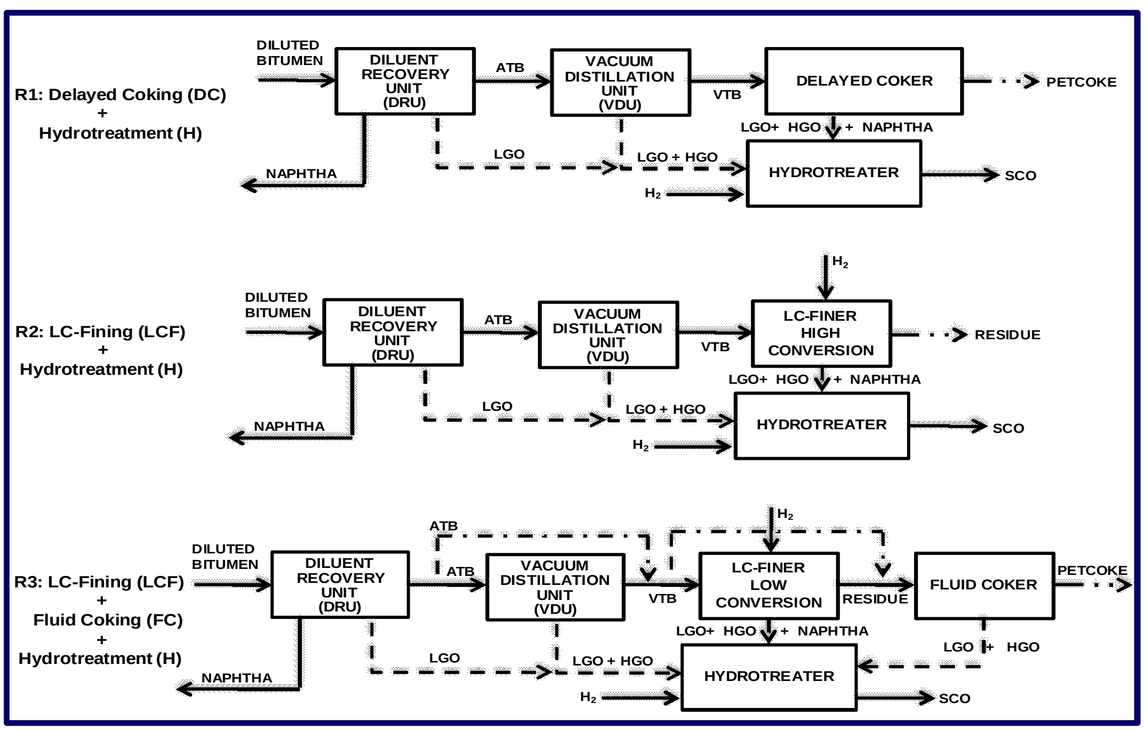

Figure 2-8. Upgrading routes [6]

As shown in Figure 2-8, the first step in upgrading consists of recovering the naphtha used to dilute the crude bitumen for its transportation via pipeline in the DRU (Diluent

Recovery Unit), i.e., the crude bitumen viscosity is too high to be transported via pipeline; thus, diluent addition is used to facilitate the transport of this heavy oil. The products from this first step are naphtha, which is recycled back to the system, LGO (light gas oil), which is sent to hydrotreatment to remove the nitrogen and sulfur impurities, and ATB (atmospheric topped bitumen), which can be transported to the VDU (vacuum distillation unit) or sent to both the VDU and the LC-finers (R3), or transported to delayed cokers (R1) (see Figure 2-8). The cokers are units where the bitumen is cracked into lighter hydrocarbons using thermal energy (thermocracking).

In the second upgrading stage, the bottom products from the VDU known as vacuum topped bitumen (VTB) are mixed with any residual ATB coming from the DRU and then sent to LC-finers (R3) or to delayed cokers (R1). Likewise, the LGO and heavy gas oil (HGO) are sent to hydrotreatment (H). In the LC-finers, the heavy hydrocarbons are cracked into lighter hydrocarbons using hydrogen. Low conversion (R3) and high conversion (R2) LC finers are currently being used. In the third upgrading stage, the products from the LC-finers, i.e., naphtha, LGO and HGO are sent to hydrotreatment. The bottom products of the LC-finers are sent to the fluid coker (R3). The fluid cokers treat the bottoms proceeding from upstream units to yield additional light hydrocarbons, i.e., LGO, HGO and naphtha (R3). In the last upgrading stage, the upstream products (naphtha, LGO and HGO) are treated with hydrogen (hydrotreaters) to remove the sulfur and nitrogen impurities to yield a light and sweet product, i.e., SCO (see Figure 2-8).

Table 2-1 shows the SCO and diluted bitumen producer schemes included in the present research work.

Table 2-1. Synthetic crude oil and commercial bitumen production schemes

Production Scheme	Stages[a]
Integrated Mining/Upgrading	
OPS_1	Mining → Hydro → DBE → DC → H
OPS_2	Mining → Hydro → DBE → LCF → H
OPS_3	Mining → Hydro → DBE → LCF → FC → H
OPS_4	Mining → Cond → DBE → LCF → FC → H ↘ Hydro ↗
Integrated SAGD/Upgrading	
OPS_5	SAGD → DC → H
OPS_6	SAGD → LCF → H
OPS_7	SAGD → LCF → FC → H
Diluted Bitumen	
DB	SAGD

[a]Cond = Conditioning, DBE = Diluted Bitumen Extraction, DC = Delayed Coking, FC = Fluid Coking, H = Hydrotreatment, Hydro=Hydrotransport, LCF = LC-Fining, SAGD = Steam Assisted Gravity Drainage.
Note: OPS_4 assumed that 25% of the oil sand processed with this scheme is treated using conditioning whereas the remaining 75% is processed using hydrotransport.

2.3 Energy Commodity Producers

The energy producers considered in the present model are expected to meet the energy demands of the oil production schemes described in the previous section (section 2.2). The energy producers included in the model are: *i)* boilers, which are used to satisfy the energy demands for process steam (*SD*), hot water (*HWD*) and SAGD extraction steam (*SSE*), *ii)* power plants for electricity generation (*PD*), and *iii)* hydrogen plants to cover the hydrogen demands for upgrading (H_U). A detailed description of the energy producers is presented next.

2.3.1 Boilers

The model considers conventional natural gas fired boilers to produce process steam (S), hot water (HW) and SAGD steam (SSE). Process steam is generated at 6,300kPa, 500ºC and hot water is produced at 35 ºC in natural gas fired boilers (SB). Similarly, the model includes boilers that produce SAGD steam at 8,000kPa, 80% quality (SSEB). In a fired boiler fuel is burned, i.e., natural gas, to produce hot combustion gases that pass over one or more tubes running through a sealed container of water. The thermal energy contained in the gases is transferred by conduction through the tube's walls thus heating the water and generating steam. Steam generation is an energy conversion process since the fuel energy is transformed into thermal energy that produces steam.

The boiler's efficiency is the ratio between the desired output from the system and the required input. The main heat loss associated to these systems is the energy exiting the boiler with the flue gas. The amount of energy loss is associated to the temperature of the flue gas and the amount of excess air supplied to the combustion process [24]. In the combustion process, the fuel comes in contact with oxygen to react and dissipate the chemical energy contained by the fuel. The unreacted fuel leaves the combustion chamber and boiler causing energy losses. This also represents a safety and environmental issue since combustion can take place in an area of the boiler that is not designed for that purpose. Also, the partial combustion of the fuel can produce carbon monoxide (CO) which is an undesired toxic gas. The lack of proper oxygen levels in the combustion process can potentially produce smoke or opacity which results in poor combustion and may also generate the formation of particles [24].

In most cases, the oxygen for the combustion process comes from ambient air that contains a high proportion of nitrogen. Nitrogen is an inert gas and does not contribute to the combustion process. However, it extracts energy from the system increasing the energy loss, and it can also contribute to the formation chemical compounds such as the nitrogen oxides (NO_x). These chemical compounds are produced from the reaction of nitrogen and oxygen gases in air during combustion, especially when high temperatures are involved. The nitrogen oxides represent air pollutants to the atmosphere and they react with other compounds to form smog and acid rain. Also, NO_x are significantly involved in the formation of tropospheric ozone (GHG) that is a powerful oxidizing agent that reacts with other chemical compounds to generate many other toxic oxides, e.g., nitroarenes, nitrosamines, nitryl chloride and nitrate radicals (involved in biological mutations [25]).

2.3.2 Hydrogen Plants

The present study considered Steam methane reforming (SMR) and Gasification, both with and without carbon dioxide capture considerations, as technologies for hydrogen production. SMR is based on an endothermic reaction typically performed at 870ºC and 30 atm. The reformer is basically a fired heater filled with multiples tubes for distributing the heat uniformly. The production process consists of the following steps: First, the feedstock (natural gas) is preheated to remove sulfur and other undesired components that may poison the catalyst. Then, the methane (CH_4) reacts with steam (H_2O) to produce synthesis gas (syngas), which is a mixture of hydrogen (H_2) and carbon monoxide (CO) in a 3:1 H_2/CO ratio [26]. This reaction is as follows:

$$CH_4 + H_2O \Leftrightarrow 3H_2 + CO \tag{1}$$

The carbon monoxide from the first step reacts with steam over a catalyst surface to produce more H_2 and CO_2. This reaction is as follows:

$$CO + H_2O \Rightarrow H_2 + CO_2 \tag{2}$$

This reaction is known as water gas shift (WGS). This reaction takes place in two stages consisting of a high temperature shift (HTS) at 350 ºC and a low temperature shift at 205 ºC. The product, H_2, is purified by liquid absorption to remove carbon dioxide (CO_2) and then treated in a Pressure Swing Adsorption (PSA) system to produce hydrogen with a purity of 99.99%.

Gasification is a hydrogen production technology that uses the integrated gasification combined cycle (IGCC) process. The raw material used in the gasifier is coal, which is prepared and fed to the gasifier in either dry or slurried form. The coal slurry reacts with steam and oxygen in the gasifier at high pressures (400-1,200 psig) and high temperatures (1,150-1,425ºC) to produce syngas, composed mainly of H_2 and CO, in a proportion greater than 85% in volume [26]. The process takes place in an oxidant atmosphere (air or pure oxygen) with a C/O ratio control that maintains the reduction conditions. When air is used as oxidant, the resulting product has lower calorific value compared to the one produced using pure oxygen because the nitrogen dilutes the gas product. However, the use of pure oxygen requires an Air Separation Unit (ASU) that increases energy consumption and the costs of this process. Gasifiers are classified based on their flow regime inside the reactor, i.e., fixed or moving bed gasifiers, fluidized bed gasifiers and entrained flow gasifiers. In the fixed gasifiers, oxygen and steam are injected into the reactor's bottom while the fuel is introduced through the top creating a counter current flow. The fuel gas travels slowly upward drying the bed of coal and lowering the output temperature of the syngas thus avoiding the need of costly cooling systems. The main disadvantage of this type of gasifier is that it only uses solid fuels that range 5-80 mm. On the other hand, fluidized bed gasifier has great fuel and load flexibility and only operates using solid crushed fuels (0.5-5 mm). This technology uses quartz or dolomite sand bed to improve heat exchange between the mixture and the fuel. Air is the most common gasifying agent in this process which is fed at minimum fluidizing velocity to control bed bubbling. In this type of gasifier the consumption of steam and oxygen is low at constant operating temperatures. On the other hand, entrained flow gasifiers involve higher velocities and higher temperatures than fixed or fluidized bed gasifiers and the fuel is fed as small particles, i.e., 200-300 µm. Also, the gasification agent flows co-currently with the fuel [27]. The syngas reaction in gasification is as follows:

$$C_aH_b \quad + \quad \frac{a}{2}O_2 \quad \Rightarrow \quad \frac{b}{2}H_2 \quad + \quad aCO \tag{3}$$

The previous equation shows the primary reaction; however, side reactions also occur on this process, i.e., steam gasification, hydrocracking, water gas shift. The CO is shifted to a reactor in order to maximize H_2 production. The CO_2 and H_2S are removed from the hydrogen stream and purified in a PSA unit yielding hydrogen with a purity of 99.99%.

2.3.3 Power Plants

The present study considered Integrated gasification combine cycle (IGCC), oxyfuel, natural gas combine cycle (NGCC), and supercritical pulverized coal (SCPC), both with and without CO_2 capture technologies, as the technologies to generate power in the Oil Sands industry. Three CO_2 capture methods are considered in the model: pre-combustion, post-combustion and oxy-combustion. Pre-combustion is modeled in IGCC plants, post-combustion in NGCC and SCPC plants, and oxy-combustion in oxyfuel power plants, respectively.

The IGCC power plants use coal as feedstock. The process starts when the coal is gasified in a high pressure, high temperature gasifier with either oxygen or air produced in an air separation unit (ASU). The resulting syngas is cooled, cleaned and fired in a gas turbine; the hot gases exiting the turbine goes through a heat recovery steam generator (HRSG) where steam is produced to drive a steam turbine that generates electricity. Electric power is also generated by the gas turbine. The removal of CO_2 and H_2S from syngas is frequently done sequentially, but simultaneous co-captured is also available [26]. According to Rubin et al. [28], IGCC plants have great potential for power production involving CCS technologies. However, this type of plants is still in the early stages of commercialization.

Instead of using air as oxidizing agent, oxyfuel power plants burn fuel in the presence of pure oxygen. To avoid damages to the turbine due to the combustion's high temperatures, part of the flue gas is recycled to lower the temperature. The flue gas of these types of plants consists primarily of CO_2 and H_2O, respectively. The water can be removed from the CO_2 stream to produce a new stream rich in CO_2 that is ideal for sequestration. Thus, this technology can yield low CO_2 emissions when coupled with a CO_2 capture technologies. In principle, oxyfuel power plants can use any fossil feedstock. This characteristic makes this type of technology potentially attractive in refineries, where low value products that can be used as potential fuel are generated as by products. Nevertheless, natural gas and coal are the most commonly feedstock used for this technology application.

NGCC power plants combine the Rankine (steam turbine) and Brayton (gas turbine) thermodynamic cycles by using heat recovery boilers that capture the energy from the gas turbine's exhaust gases. The resulting steam produced by the process is used to drive a turbine that generates electricity. In the gas turbine, natural gas is burned in a combustion chamber using compressed air as oxidizer. The high pressure, high temperature gas enters a turbine section where it expands powering a generator and a compressor. Then, the high pressure steam produced by the heat recovery boilers can also generate electricity using the steam turbines [26]. In the United States the estimated low cost of electricity due to low natural gas prices during the 1980s and early 1990s led to large investments in NGCC plants over the past decades. Nevertheless, where coal fired plants are available, the NGCC plants are no longer used because the natural gas price has significantly increased compared to past decades. Accordingly, the utilization factor of NGCC plants in the U.S. has fallen approximately to 30 percent [28].

SCPC burns pulverized coal in a boiler in order to produce the steam that drives large turbines for electrical power generation. When NGCC and SCPC plants operate with CO_2 capture, monoethanol amine (MEA) is used to remove the carbon dioxide exiting the turbine. Table 2-2 shows the energy commodity producers included in the present study.

The carbon capture and storage systems require significant energy penalties (consumption) that commonly consists of the reduction in the plant power output for a constant fuel input, i.e., plant derating. In certain power technologies such as IGCC plants, the implementation of CO_2 capture technologies changes the plant output and fuel input. The energy penalty is based on the change in net plant rate or efficiency. According to information reported by Rubin et al. [28], the energy penalties associated to CCS for coal power plants is 24%, NGCC plants 15% and IGCC plants 14%. The previous energy penalties significantly increase the cost of CO_2 capture and storage because the reduction in the plant power output originates higher costs per plant capacity and unit of product.

Additionally, the use of CCS technologies involves the increase of the limestone consumed in coal power plants to control SO_2 emissions from flue gas (desulfurization system). Also, the consumption of ammonia increases in catalytic reactions to control the NO_x emissions to the atmosphere. In addition, the amount of ash, slag residues and solids produced by the desulfurization systems for coal power plants and IGCC plants is increased. The solids residues could constitute a solid waste or a saleable byproduct depending on the market demand for gypsum (coal power plants) and sulfur (IGCC plants) [28].

Table 2-2. Energy Producers

Energy producer[b]	Source
Boilers	
NG-at 6,300 kPa and 500 ºC steam-w/o CO_2 capture (SB)	(Harrel, 2002)
NG-80% steam at 8,000 kPa-w/o CO_2 capture (SSEB)	(Harrel, 2002)
Power plants	
NGCC w/o CO_2 capture (PP_1)	(Rubin, Rao & Chen, 2004)
Supercritical coal w/o CO_2 capture (PP_2)	(Rubin, Rao & Chen, 2004)
IGCC w/o CO_2 capture (PP_3)	(Ordorica, Douglas, Croiset & Zheng, 2006)
IGCC with 88% CO_2 capture via Selexol (PP_4)	(Ordorica, Douglas, Croiset & Zheng, 2006)
IGCC with 88% CO_2 + H_2S co-capture via Selexol (PP_5)	(Ordorica, Douglas, Croiset & Zheng, 2006)
NGCC with 90% CO_2 capture via MEA (PP_6)	(Rubin, Rao & Chen, 2004)
Supercritical coal with 90% CO_2 capture via MEA (PP_7)	(Rubin, Rao & Chen, 2004)
NG Oxyfuel with CO_2 capture (PP_8)	(Davison, 2007)
Coal Oxyfuel with CO_2 capture (PP_9)	(Davison, 2007)
Hydrogen plants	
SMR w/o CO_2 capture (HP_1)	(Simbeck & Chang, 2002); (Simbeck, 2004)
Coal gasification w/o CO_2 capture (HP_2)	(Chiesa et al., 2005); (Kreutz et al., 2005)
SMR with 90% CO_2 capture via MEA (HP_3)	(Simbeck & Chang, 2002); (Simbeck, 2004)
Coal gasification with 90% CO_2 capture via Selexol (HP_4)	(Chiesa et al., 2005); (Kreutz et al., 2005)
Coal gasification with 90% CO_2 + H_2S co-capture via Selexol (HP_5)	

[b]NG = Natural Gas, NGCC = Natural Gas Combined Cycle power plants, IGCC = Integrated Gasification Combined Cycle power plants, SMR = Steam Methane Reforming hydrogen plants, MEA = Mono-ethanolamine.

2.4 Mathematical models for the Oil Sands operations

Models that describe the Canadian Oil Sands operations have been reported in the open literature. A model that determines the energy demands and Greenhouse Gas (GHG) emissions of the Canadian Oil Sands industry have been developed [6]. In that study, the energy demands, i.e., electricity, hydrogen, process steam, SAGD steam, hot water, process fuel (natural gas) and diesel fuel, involved in the production of synthetic crude oil (SCO) and commercial crude bitumen are modeled and quantified based on current commercial oil production schemes. Moreover, the SCO production schemes considered in that study were *i*) crude bitumen extracted via mining upgraded to SCO and *ii*) crude bitumen extracted via

SAGD upgraded to SCO. Additionally, the model developed in that study included three different upgrading routes to convert the crude bitumen into SCO *a*) LC-Fining/Fluid Coking/Hydrotreatment, *b*) Delayed Coking/Hydrotreatment, and c) LC-Fining/Hydrotreatment. That model also considers the production of commercial crude bitumen via SAGD extraction. The SCO production schemes based on mining extraction included four main processing stages 1) *mining* where the oil sand is mined from the ground, 2) *conditioning/hydrotransport* where the sand is mixed with hot water to separate the crude bitumen from the sand, 3) *extraction plant* where the crude bitumen is separated from the slurry and recovered and 4) *upgrading* where the crude bitumen is upgraded to SCO (more valuable product). Likewise, the SCO production schemes based on SAGD considered two processing stages 1) *SAGD extraction* where steam is injected through a well into the reservoir and the heated bitumen extracted by a parallel production well and 2) *upgrading*. The upgrading process for SAGD SCO is analogous to that described previously in mined SCO production. The model calculates the mass and energy balances involved in the stages previously described for SCO and commercial crude bitumen productions. Similarly, the model proposed in the current work considers the aforementioned oil production schemes, processing stages and upgrading routes because they are the most common commercial technologies employed by Oil Sands operators [19]. The model presented by Ordorica et al. [6] includes two case studies, a base case (year 2003) and future production scenarios (year 2012 and 2030). The base case considers the Oil Sands operations in Alberta for year 2003. That year was selected because there was sufficient available information reported in the literature describing the operations for that year [19, 29]. Thus, the oil production schemes considered for the base case are mined bitumen upgraded to SCO and commercial bitumen via SAGD extraction. The production levels expected from each individual oil production scheme were obtained from reports on the Oil Sands operations [19, 29]. These values were used as constant parameters (inputs) in the model to calculate the energy demands of the oil producers based on the historical data. Furthermore, the energy producers available in 2003 were also known *a priori*. Consequently, steam reforming was used for H_2 production, natural gas combined cycle was used to generate electricity whereas natural gas fired boilers produced the steam and hot water. None of these energy producers considered CCS for the 2003 case study. The model also calculates the associated GHG emission of the operations based on the energy producers. The data from this particular case study is used in the present work as part of the validation process of the proposed energy model. Also, the GHG emissions are calculated based on the emissions of the energy producers selected in the optimization problem. The second case study (years 2012 and 2030) used forecasts for the expected production levels of SCO and commercial bitumen for the years 2012 and 2030 to project the associated energy demands. These case studies include SAGD bitumen upgraded to SCO as additional production scheme since it is expected to be a technology employed for the production of SCO in those years. However, the GHG emissions are not calculated in the future scenarios (years 2012 and 2030) since the future energy production technologies, e.g., hydrogen, power, steam, are unknown in that study and no assumptions regarding the energy technologies were made for the years 2012 and 2030. According to that study, the demands for SAGD steam, hydrogen, process steam, and power will experience a sudden growth until 2030. More specifically, the SAGD steam and hydrogen requirements are expected to increase 6 times by 2030 compared to the demands for the year 2003. Moreover, the process steam and electricity demands are projected to double by 2012 and increase by a factor of 2.4 between 2012 and 2030. The study also identified potential opportunities to reduce GHG emission by implementing low GHG intensity energy producer technologies [6].

On the other hand, an optimization model that minimize the energy production costs with carbon captured technologies for CO_2 mitigation in the Canadian Oil Sands industry have been reported in the literature [7]. The main objective of the model is to minimize the annual production costs of the energy commodities demanded by the Oil Sands operators, i.e., power, hydrogen, process steam, SAGD steam and hot water, subject to constraints on the level of GHG emissions. Thus, the model developed in that study determines the optimal combination of power plants (power producers), hydrogen plants (hydrogen producers) and natural gas fired boilers (process steam, SAGD steam and hot water producers) that satisfy fixed energy requirements (model inputs) associated to expected production levels of the Oil Sands operators. That model included steam methane reforming (SMR) and coal gasification as hydrogen producers. Also, it included coal (SCPC), natural gas combined cycle (NGCC), integrated gasification combined cycle (IGCC) and oxyfuel power plants. The hydrogen and power plants were modeled with and without CO_2 captured technologies. The model in [7] generates the optimal energy production infrastructure and determines the corresponding costs and GHG emissions involved in the generation of the energy commodities required in the production of SCO and commercial bitumen. The model also calculates the carbon capture and storage (CCS) cost associated to CO_2 abatement, e.g., CO_2 transport costs and CO_2 storage costs. The model considered a case study that aims to minimize the costs of the historical energy demands of the Oil Sands industry for the year 2003 subject to CO_2 emission constraints. That study determined the annual energy production cost considering two cases: *i*) for a CO_2 emission baseline, and *ii*) for CO_2 emission reductions relative to the emission baseline, i.e., 10-35% reduction. The case study results showed the potential to reduce the energy costs of SCO production by 2-7% while reducing CO_2 emissions up to 30% with respect to a baseline. NGCC and PC power plants without CO_2 capture are favored over IGCC or oxyfuel plants at CO_2 reduction levels under 20%. Similarly, the current work presents energy producers, e.g., boilers, power and hydrogen plants, and CCS technologies equivalent to those presented by Ordorica et al. in [7]. Furthermore, data from the case study for the year 2003 was used as complementary information to validate the present energy.

In another study by Ordorica et al. [8], the authors used the energy model developed in [7] to forecast optimal energy producer's infrastructure for the year 2030. Accordingly, the model used as inputs the energy demands associated with the projected production of SCO and commercial bitumen for the year 2030. The model estimated the total annual cost needed to supply energy to the Oil Sands industry, the corresponding optimal energy infrastructure and CO_2 emissions. The study determined the annual supply cost considering two cases: *i*) for a CO_2 emission baseline, and *ii*) for CO_2 emission reductions relative to the emission baseline up to 38.6%. The model's results reported in [8] show that the optimal energy production infrastructures depend on the CO_2 emission constraints. Also, NGCC and PC power plants without CO_2 capture technologies are favored by the energy model for CO_2 reduction levels of up to 30%, whereas CO_2 reductions of less than 35% can be achieved with cost savings compared to the baseline emission case.

The models currently available in the literature aimed to determine the most suitable configuration of energy producers and their corresponding capacities that minimize the energy generation costs of the Oil Sands for given energy demands [7, 8]. That is, the energy demands that correspond to a fixed oil production infrastructure, i.e., fixed oil production capacities and schemes from the Canadian Oil Sands, need to be specified *a priori* and are assumed to be the inputs to the models. Thus, the results obtained with these models are limited because the future project planning and scheduling of the Oil Sands operation can only be done for the energy commodities' infrastructure, i.e., determination of the optimal oil production schemes (oil producers) was not considered in the analysis. Also, the energy producers configuration obtained by those models may not be optimal because they were calculated based on fixed oil production schemes. Therefore, there is no guarantee that combinations between the different oil production schemes may return a more economically attractive energy infrastructure. Based on the above, a model that determines both the oil producers and energy producer's infrastructure is currently not available and represents the subject of the present research study. That is, the model proposed in the present work aims to simultaneously optimizes the oil production schemes and the energy infrastructure for the Oil Sands operations.

Chapter 3

3 Oil Sands Operations Model

3.1 Overview

This section presents the main features of the integrated optimization model developed in this work to determine the production energy costs of the Canadian Oil Sands operations. The key feature of this energy model is that the Oil Sands producers, the energy commodity producers, and their corresponding capacities are treated as decision (optimization) variables. The proposed model also includes environmental constraints in its formulation, i.e., CO_2 emission target. The integrated model offers the potential to find a more economically attractive scenario for the Oil Sands operations that those reported in previous studies [7, 8]. This is because the integrated model will search for both the set of SCO producers and energy commodity producers (and their corresponding capacities) that will meet the Oil Sands producers' energy requirements at the lowest energy cost. Thus, the integrated model approach expands the optimization algorithm's search space to consider optimal oil production schemes and energy commodity configurations that may result in more economical scenarios than those obtained by the previous modeling tools [7, 8].

The structure of the optimization model developed on this study is shown in Figure 3-1. The model inputs appear at the top in the Figure (total bitumen and SCO production). Following from top to bottom are the Oil Sands producers, i.e., commercial crude bitumen producer (*DB*), Integrated SAGD/Upgrading and Mining/Upgrading SCO producers (OPS_i). The oil producers represent the processes that require specific energy demands from the energy producers to maintain its operations. Following Figure 3-1, the energy demands included in the model are: process steam (*SD*), hot water (*HWD*), SAGD extraction steam (*SSE*), electricity (*PD*), hydrogen (H_U), process fuel (PF_U), and diesel (*D*). The energy demands are met by natural gas fired boilers, power plants, hydrogen plants, and external providers that supplied the energy requirements for process fuel (natural gas) and diesel. These processes/units represent the energy suppliers of the Oil Sands industry and are shown at the bottom of Figure 3-1. Each of the stages shown in Figure 3-1 is described in detail in this section. Section 3.2 describes the inputs of the integrated energy optimization model. The production scheme's models, i.e., the crude bitumen extraction methods, the bitumen recovery stages, and the different bitumen upgrading technologies, are presented in section 3.3. The energy commodity producer's models are presented in section 3.4 whereas additional costs considered in the model's formulation are described in section 3.5. The integrated energy model as well as the main modeling features are presented in section 3.6.

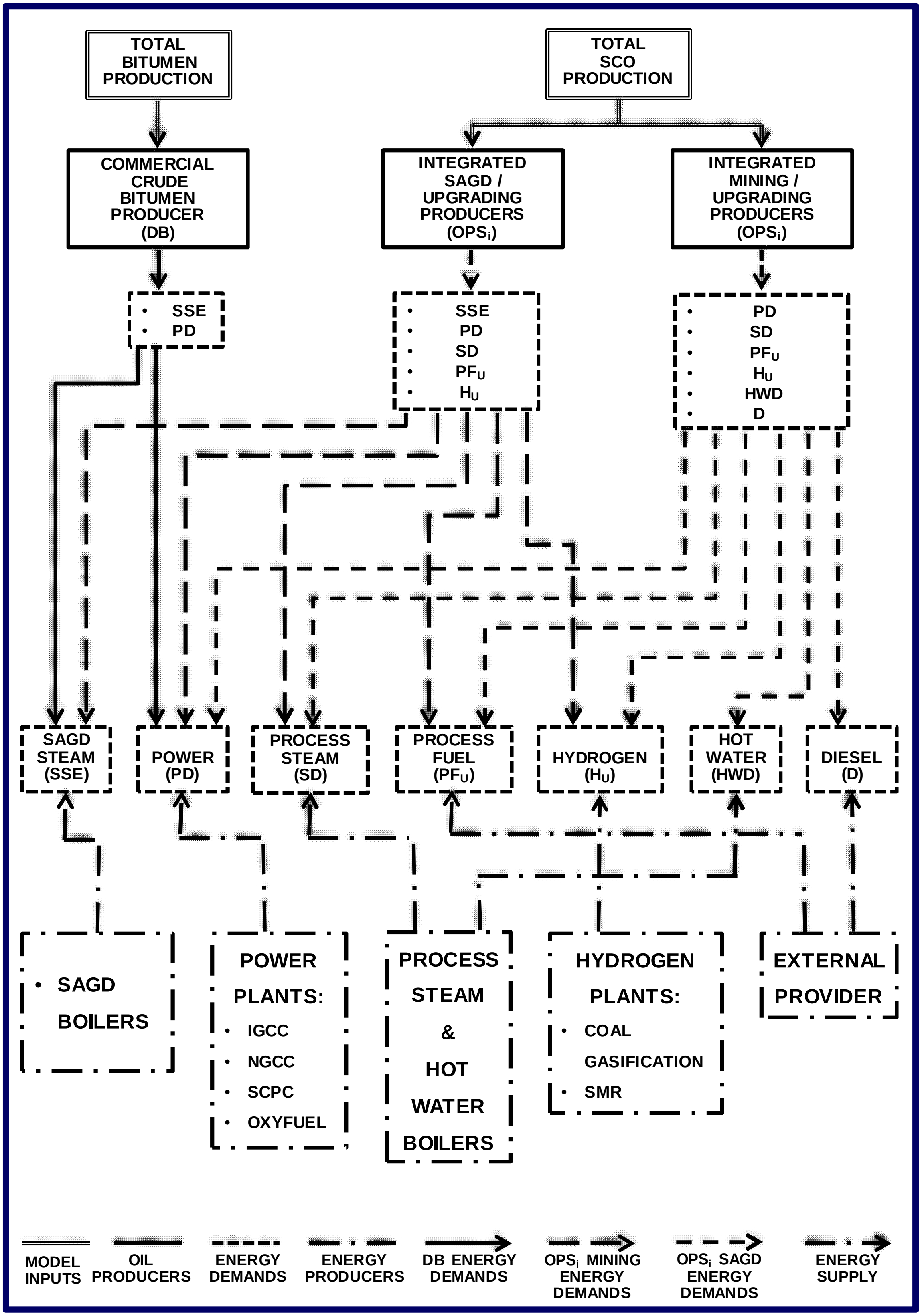

Figure 3-1. Energy optimization model structure

3.2 Inputs

The inputs considered in the model are represented by the total diluted bitumen (*TDB*) and total SCO (*TSCO*) productions expected for a given year, the carbon dioxide emission target (CO_2E) and the maximum number of energy producers available. The oil production values and the CO_2 emission targets are specified by the user or obtained from forecasts in the literature [11]. The maximum number of energy producers available is also defined by the user. The present model assumes that the total diluted bitumen production (*TDB*) is equal to the crude bitumen obtained via SAGD extraction (*DBR*) for commercialization (bbl bitumen/d), i.e., *TDB*=*DBR*. That is, the present work assumes that the total diluted bitumen is produced only by SAGD extraction. The carbon dioxide emission target (CO_2E) is calculated in the model as follows:

$$CO_2E = CO_2B\left(1 - CCO_2\right) \quad (4)$$

where CO_2E (specified by the user) is the CO_2 emission target, which is a function of the baseline carbon dioxide emission of the Oil Sands operations, CO_2B (tonne CO_2/h). This value is defined using a *business as usual* (BAU) scenario [7, 8]. In a BAU scenario, the technologies that dominate the production of the energy commodities in the Oil Sands industry are assumed to remain constant over time. Previous Oil Sands operation models have used this scenario to define their baseline CO_2 emission (BAU) [7, 8]. For comparison purposes, the present study used the 2003 BAU scenario. Thus, the energy production processes are based on the conventional technologies used by Oil Sands operators in 2003. Moreover, these technologies did not consider CO_2 capture and storage methods at that time (year 2003). Accordingly, SMR and NGCC are the technologies chosen to produce hydrogen and electricity in the BAU scenario whereas natural gas fired boilers are used to produce hot water and steam [6-8]. In equation (4), the term CCO_2 represents the reduction of CO_2 emissions needed to meet the target, which is accomplished using CO_2 capture technologies.

3.3 Mathematical models for the Oil Production Schemes

The present integrated energy model considers different SCO production schemes, which are a combination of a crude bitumen extraction method (mining or SAGD) with an upgrading technology, i.e., thermocracking, hydrocracking. As mentioned above, SAGD extraction is considered as the only method employed for the production of commercial crude bitumen, i.e., *DBR*. The total SCO production (*TSCO*) is estimated in the model as follows:

$$TSCO = \sum_{i=1}^{N} SO_i \tag{5}$$

where sub-index i represents a SCO production scheme and N is the total number of production schemes considered in the model. SO_i represents the mined and SAGD crude bitumen upgraded to SCO produced by each scheme (bbl SCO/d). Equation (5) is used in the model to select the most suitable SCO production schemes and its corresponding production levels. Each of the stages involved in the schemes are described next. These production schemes represent the most common technologies currently used in the Oil Sands operations to produce SCO. These technologies are based on production processes use by Syncrude Canada Ltd., Suncor Energy Inc. and Shell Canada Limited, which are the oil companies with more tradition in Alberta. Similarly, the model considers the technologies that are expected to become attractive production methods in the medium term future (SAGD SCO). Thus, the present model can be used by Oil Sands companies and governmental planning energy entities such as the National Energy Board of Canada to help forecasting future energy scenarios, which may be used to design Energy Roadmaps. However, the implementation of the results obtained with the present model may need to be enforced or coordinated by a federal or provincial government agency since every company involved in the Oil Sands operations have different interests.

3.3.1 Mining Extraction

Mining extraction is a surface method only used for SCO production in the model. The amount of mined oil sand in the model depends on the characteristics of the integrated Mining/Upgrading production schemes and their corresponding production levels. The energy demand for this process is diesel, which is consumed by the fleets of shovels and trucks used for mining the oil sand. The model and number of vehicles included in the fleets correspond to a normal Oil Sands operation [6]. The total amount of diesel (D) consumed by the fleets depend on the specifications of each individual vehicle, i.e., fuel consumption parameters, the number of trucks and shovels used in the fleets. The diesel consumed by the fleet of shovels is formulated as follows:

$$DSH = \sum_{k=1}^{K} SH_k \ D_k \tag{6}$$

where DSH is the amount of diesel (L/h) consumed by the shovels' fleet, K is the total models of shovels available in the fleet, SH_k is the number of vehicles of model k used in the fleet and D_k is the fuel consumption expected of the k^{th} model(L/h) [6]. The diesel consumption by the trucks' fleet (DT) is calculated as follows:

$$DT = \sum_{l=1}^{L} T_l \ D_l \tag{7}$$

where L represents the total number of trucks' model in the fleet, T_l is the number of vehicles of model l used in the fleet, and D_l is the diesel consumption (L/h) [6]. Based on the above, the total diesel demand for the Oil Sands operation is estimated as follows:

$$D = DSH + DT \tag{8}$$

3.3.2 SAGD Extraction

This process is an in-situ extraction method used for commercial diluted bitumen and SCO production in the model [30]. The amount of SAGD bitumen is calculated based on the characteristics of the integrated SAGD/Upgrading production schemes, i.e., SCO conversion; the DB scheme and their corresponding production levels. This method requires power and SAGD steam (at 8000 kPa with a quality of 80%), which is injected into the oil reservoir at a typical steam to oil ratio (SOR=2.4). The SAGD steam demand for this process is estimated as follows:

$$SSE = SOR\left(\frac{DBR}{CFB} + \sum_{i=1}^{N} PS_S(i)\ BIT_i\right)$$
$$PS_S(i) = \begin{cases} 1 & \text{if } i \text{ follows integrated SAGD/Upgrading production scheme} \\ 0 & \text{otherwise} \end{cases} \tag{9}$$

where *SSE* represents the total steam consumption in SAGD extraction, which is used for diluted bitumen and SCO production via SAGD schemes. Accordingly, *SSE* (tonne/h) is a function of the bitumen production rate via SAGD for SCO BIT_i (tonne/h) and crude bitumen *DBR* (bbl/d) productions. BIT_i and *DBR* are the bitumen inputs required by the production schemes to meet the SCO and diluted bitumen production demands, respectively. *CFB* (148.87 h·bbl/d/tonne bitumen) is a conversion factor; *DBR* is defined by the user whereas BIT_i is calculated internally by the model when selecting the optimal configuration of oil production schemes and their corresponding production levels to satisfy the expected SCO production for a given scenario. Since BIT_i represents the amount of crude bitumen extracted via SAGD to be processed and upgraded to SCO, BIT_i depends on the level of SCO produced by the oil production schemes. Also, *SSE* is a function of the SOR parameter. The power demands for SAGD extraction (*PSE*) are calculated as follows:

$$PSE = P_{SE}\left(\frac{DBR}{CFB} + \sum_{i=1}^{N} PS_S(i)\ BIT_i\right) \tag{10}$$

where P_{SE} is a parameter used to indicate the power requirements for SAGD extraction (P_{SE} = 3.1 kW/tonne bitumen [30]).

3.3.3 Bitumen Preparation

The processes involved in the bitumen preparation are conditioning and hydrotransport.

• **Conditioning:** When this stage is considered in the SCO production schemes, only 25% of the oil sand processed is conditioned whereas the remaining 75% is processed using hydrotransport in the model. The main energy consumptions for conditioning are hot water (HW_c) and steam (S_c). The hot water demand for this process is calculated as follows:

$$\begin{aligned} HW_C &= WOSR_C \sum_{i=1}^{N} UR_F(i)\ LF_C(i)\ OSR_i \\ UR_F(i) &= \begin{cases} 1 & \text{if } i \text{ follows upgrading route R3} \\ 0 & \text{otherwise} \end{cases} \\ LF_C(i) &= \begin{cases} 1 & \text{if } i \text{ follows a production scheme with conditioning stage} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \tag{11}$$

As shown in (11), HW_c (tonne/h) depends on the mined oil sand rate OSR_i (tonne /h) and the water to oil sand ratio for conditioning ($WOSR_C$ = 0.333 tonne of water/tonne oil sand [31]). The steam requirement in this stage (S_c) is formulated as follows:

$$S_C = SOSR_C \sum_{i=1}^{N} UR_F(i)\ LF_C(i)\ OSR_i \tag{12}$$

where $SOSR_c$ is the steam to oil sand ratio in conditioning ($SOSR_c$ = 0.036 tonne of steam/tonne of oil sand [31]). The water used as feedstock by boilers for the production of steam and hot water may represent a large financial cost because water is used in most of the stages involved in the production of commercial bitumen and SCO.

• **Hydrotransport:** The energy demands in this stage include hot water and power. The hot water demand for this stage is calculated as follows:

$$HW_H = WOSR_H \sum_{i=1}^{N} PS_M(i)\, OSR_i$$
$$PS_M(i) = \begin{cases} 1 & \text{if } i \text{ follows integrated Mining/Upgrading production scheme} \\ 0 & \text{otherwise} \end{cases} \tag{13}$$

where HW_H, the hot water consumed in hydrotransport, is a function of the mined oil sand rate (OSR_i) and the water to oil sand ratio for hydrotransport ($WOSR_H$ = 0.30 tonne of water/tonne of oil sand). The power demand (P_H) is calculated as follows:

$$P_H = \sum_{i=1}^{N} PS_M(i)\, ST_i\, d_i\, SPF_i \tag{14}$$

where ST_i (tonne/h) is the slurry (70% of solids content), d_i (m) is the distance from the mining site to the extraction plant, and SPF_i (kWh/tonne slurry/m) is the slurry pumping factor. ST_i depends on the rate of mined oil sand being processed and d_i is a model parameter.

3.3.4 Diluted Bitumen Extraction

The mined SCO production schemes considered in the model follow a two step hot water process in the bitumen extraction plant [31]. In the primary extraction, the bitumen froth from hydrotransport and conditioning is separated from the slurry using steam and hot water. In secondary extraction; the bitumen froth is diluted in naphtha, and then centrifuged to separate the remaining sand and water from the bitumen. Thus, the energy requirements associated to this stage are hot water, steam and electricity. The hot water demand in bitumen extraction is as follows:

$$HW_{BE} = WOSR_{BE} \sum_{i=1}^{N} PS_M(i)\, OSR_i \tag{15}$$

where HW_{BE} (tonne/h), the total hot water demand in primary extraction [31], is a function of OSR_i and the water to oil sand ratio for diluted bitumen extraction ($WOSR_{BE}$ = 0.41 tonne water/tonne of oil sand [31]). The steam demands for this process in secondary extraction are calculated as follows:

$$S_{BE} = SFR \sum_{i=1}^{N} PS_M(i)\, BF_i \tag{16}$$

where BF_i (tonne froth/h) is the crude bitumen froth coming from primary extraction and *SFR* is a parameter that defines the steam requirement for secondary extraction in the stage (*SFR*= 0.040 tonne of steam/tonne froth [31]). The power demand is calculated from the following equation:

$$P_{BE} = \sum_{i=1}^{N} PS_M(i)\left(PT_i + PC_i\right) \tag{17}$$

where, P_{BE} (kW) is the total power demand for this stage, which comprises the power requirements to pump tailings to disposal (PT_i) and power for centrifugation (PC_i).

3.3.5 Upgrading

The bitumen coming from the diluted bitumen extraction plant is upgraded to SCO on this stage. The present model considers three upgrading routes shown in Figure 2-8. Bitumen upgrading requires large amounts of energy, i.e., steam, hydrogen, power, and process fuel. The total steam demand for upgrading (S_U) is formulated as follows:

$$S_U = \sum_{i=1}^{N} \left(DBIT_i\, SDRU + \left(ATB - ATBF\right)_i SVDU + FB_i\, SFCU\right) \tag{18}$$

where $DBIT_i$ (tonne/h) is the diluted bitumen entering to the upgrading stage whereas *SDRU* is a parameter defining the steam requirements in the DRU (*SDRU*= 0.30 tonne steam/ tonne diluted bitumen). *SVDU* and *SFCU* represent the steam requirements for the VDU and FCU, respectively (*SVDU*= 0.07 tonne steam/tonne diluted bitumen). The VDU unit was modeled based on information available on the literature [32]. The term ATB_i (tonne/h) is the atmospheric topped bitumen, $ATBF_i$ (tonne/h) is the atmospheric topped bitumen feeding the LC-finers and FB_i represents the LC-finer bottom oil fractions.

The hydrogen demand for upgrading considers the hydrogen needed for hydrocracking and hydrodesulphurization. The hydrogen for hydrocracking is calculated as follows:

$$H_{HC} = \frac{1}{\rho_{H_2}} \sum_{i=1}^{N} HC(i) \left(\left(VTB_i + ATBF_i \right) HLF + VTB_i \, HHF \right)$$
$$HC(i) = \begin{cases} 1 & \text{if } i \text{ follows hydrocracking upgrading schemes, i.e., R2 and R3} \\ 0 & \text{otherwise} \end{cases} \tag{19}$$

where H_{HC} is the total hydrogen used for hydrocracking, VTB_i is the vacuum topped bitumen (tonne/h) and *HLF* denotes a parameter that indicates the hydrogen requirements for low conversion LC-finers (*HLF* = 6.046 ft^3 H_2/tonne bitumen). This first term in the equation represents the low conversion LC-finer hydrogen consumption whereas the second term represents the high conversion LC-Finer hydrogen demands. The low conversion LC-finers specifications were taken from [33-35] whereas the high conversion LC-Finer was modeled according to data from [31]. The parameter *HHF* is the hydrogen required for the high conversion LC-finers (*HHF* = 8.464 ft^3 H_2/tonne bitumen) whereas ρ_{H2} is the hydrogen density (ρ_{H2} = 423,000 ft^3/tonne). The total hydrogen (H_{HT}) demand for hydrotreatment is modeled as follows:

$$H_{HT} = \frac{1}{UCF\ \rho_{H_2}} \sum_{i=1}^{N} \left(\left(\frac{LGO_i}{DLGO} \right) HLGO + \left(\frac{HGO_i}{DHGO} \right) HHGO + \left(\frac{NT_i}{DNT} \right) HNT \right) \tag{20}$$

where *DLGO*, *DHGO* and *DNT* are the average densities of the oil fractions entering the hydrotreaters for the LGO, HGO and NT streams, respectively. The numerical values for these parameters were taken from [32] (*DLGO* = 0.9125 tonne/m^3, *DHGO* = 0.9713 tonne/m^3, and *DNT*= 0.744 tonne/m^3). *HLGO*, *HHGO* and *HNT* are parameters that specify the hydrogen requirements for LGO, HGO and NT in hydrotreaters respectively, (*HLGO* = 1,150 ft^3/bbl, *HHGO* = 1,150 ft^3/bbl, and *HNT* = 930 ft^3/bbl [33]). The term *UCF* in (20) is a unit conversion factor (*UCF* = 0.1589873 m^3/bbl). Based on the above, the total hydrogen demand in upgrading (H_U) is defined as follows:

$$H_U = H_{HC} + H_{HT} \tag{21}$$

The power demands in upgrading depend on each upgrading route. For schemes following the upgrading route R1 (see Figure 2-8) the total power requirement is as follows:

$$\begin{gathered} P_{UD} = \frac{PDDC}{DVTB} \sum_{i=1}^{N} UR_D(i)\ VTB_i \\ UR_D(i) = \begin{cases} 1 & \text{if } i \text{ follows upgrading route R1} \\ 0 & otherwise \end{cases} \end{gathered} \tag{22}$$

where P_{UD} (kW) is the power demand on delayed coking based schemes, *PDDC* is a parameter that defines the electricity requirement for delayed coking (*PDDC*=3.9kWh/bbl), and *DVTB* the vacuum topped bitumen density (*DVTB*=0.16805tonne/bbl). The power requirement for the production schemes following the upgrading route R2 is estimated from the following expression:

$$
\begin{aligned}
&P_{UL} = \frac{PDLF}{DLF}\sum_{i=1}^{N} UR_L(i)\ VTB_i \\
&UR_L(i) = \begin{cases} 1 & \text{if } i \text{ follows upgrading route R2} \\ 0 & \text{otherwise} \end{cases}
\end{aligned}
\tag{23}
$$

where P_{UL} is the power demand in LC-Fining based schemes, *PDLF* is a parameter that indicates the power demands per bitumen feed in high conversion LC-finer (*PDLF*= 16.5 kWh/bbl), and *DLF* is the average LC-Finer feed density (*DLF*=0.1654 tonne/bbl [32]). The total power demand from schemes that include the upgrading route R3 is defined as follows:

$$
P_{UF} = \frac{1}{DLF}\sum_{i=1}^{N} UR_F(i)\left(PDHF\,(VTB + ATBF)_i + FB_i\ PDFC\right) \tag{24}
$$

where P_{UF} is the power demand for schemes including LC-fining and fluid coking (R3), the model parameters *PDHF* and *PDFC* represent the power requirements for low conversion LC-finer and fluid coking processes, respectively (*PDHF*= 16.5 kWh/bbl [36], *PDFC*= 6 kWh/bbl [31]). Based on the above, the total electricity demand for the upgrading stage (P_U) can be calculated as follows:

$$
P_U = P_{UD} + P_{UL} + P_{UF} \tag{25}
$$

The process fuel requirements in upgrading depend on each upgrading route. Process fuel (natural gas) is consumed in different steps of the upgrading stages. The corresponding energy demands for natural gas are calculated as follows:

$$
PF_{UD} = \frac{FDDC}{DVTB\ HVNG}\sum_{i=1}^{N} UR_D(i)\ VTB_i \tag{26}
$$

$$
PF_{UL} = \frac{FDLCF}{DLF\ HVNG}\sum_{i=1}^{N} UR_L(i)\ VTB_i \tag{27}
$$

$$
PF_{UF} = \frac{FDLCF}{DLF\ HVNG}\sum_{i=1}^{N} UR_F(i)\ \left(VTB + ATBF\right)_i \tag{28}
$$

where *FDLCF* and *FDDC* are parameters that represent the process fuel requirements for LC-Fining and Delayed-Coking processes respectively (*FDLCF*=93.47 MJ/bbl [36], *FDDC*= 153 MJ/bbl [36]), and *HVNG* is the typical Western Canadian Gas heating value in the model (*HVNG* = 38.05 MJ/m^3). Accordingly, the total process fuel demands for upgrading (PF_U) is calculated as follows:

$$PF_U = PF_{UD} + PF_{UL} + PF_{UF} \tag{29}$$

3.3.6 Additional Power Requirements

The proposed integrated model also considers additional power demands such as those needed by SMR hydrogen plants and in the CO_2 capture for transporting the gas from Fort McMurray to depleted oil fields nearby Edmonton, like Red Water Field. The model considers different hydrogen plants (see section 3.4.8) but only the steam methane reforming (SMR) requires energy to operate. The remaining plants (gasification) co-generate power to maintain themselves and add electricity to the Oil Sands supply. The power demand for SMR hydrogen plants (*PHP*) is calculated as follows:

$$\begin{gathered} PHP = \sum_{j=1}^{J} HPS(j)\, HP_j\, PC_j \\ HPS(j) = \begin{cases} 1 & \text{if hydrogen plant } j \text{ is of type SMR} \\ 0 & \text{otherwise} \end{cases} \end{gathered} \tag{30}$$

where *J* represents the total number of hydrogen plant types considered in the model. HP_j is the amount of hydrogen produced in the plants (tonne H_2/h) and PC_j the power consumption in the plants (kWh/tonne H_2). The power demand to transport the CO_2 capture in hydrogen plants (*PCTH*) is formulated as follows:

$$PCTH = PL \sum_{j=1}^{J} HPC(j)\, CCH_j\, CPCT$$

$$HPC(j) = \begin{cases} 1 & \text{if hydrogen plant } j \text{ capture } CO_2 \\ 0 & \text{otherwise} \end{cases} \tag{31}$$

where CCH_j is the amount of CO_2 captured in hydrogen plants (tonne CO_2/h), *CPCT* is the compression power for CO_2 transport (kWh/tonne CO_2/km), and *PL* is the pipeline length (km). The power demand to transport the CO_2 capture in power plants (*PCTP*) is calculated as follows:

$$PCTP = PL \sum_{m=1}^{M} PPC(m)\, CCP_m\, CPCT$$

$$PPC(m) = \begin{cases} 1 & \text{if power plant } m \text{ capture } CO_2 \\ 0 & \text{otherwise} \end{cases} \tag{32}$$

where *M* represents the number of power plant types considered in the model and CCP_m is the amount of CO_2 captured in power plants (tonne CO_2/h).

3.3.7 Energy Demands

The total energy demands are estimated based on the energy requirements needed by each one of the production schemes. Thus, the energy demands considered in the model are: power, steam, hot water, hydrogen, diesel, and process fuel. As described in the previous sections, Equations (33-35) show the expressions used to determine the power demand, the process steam and hot water demands for the Oil Sands production schemes. The total power demand, *PD* (kW), represent the electricity demands from the different production schemes. Likewise, the total process steam demand, *SD* (tonne/h), is a function of the steam requirements in conditioning (S_C), diluted bitumen extraction (S_{DBE}) and upgrading (S_U), respectively. Similarly, *HWD*, the total demand of hot water, is calculated based on the hot water consumption in conditioning (HW_C), hydrotransport (HW_H) and diluted bitumen extraction (HW_{DBE}). The expressions to estimate the energy demands for diesel, SAGD steam and hydrogen for upgrading have been previously defined in equations (8), (9) and (21), respectively.

$$PD = PSE + P_H + P_{BE} + P_U + PHP + PCTH + PCTP \tag{33}$$

$$SD = S_C + S_{BE} + S_U \tag{34}$$

$$HWD = HW_C + HW_H + HW_{BE} \tag{35}$$

3.4 Energy producers Model

The commodity producers supply the energy requirements to maintain the Oil Sands operations. The energy commodities considered are electricity, hydrogen, process steam, hot water, SAGD extraction steam, process fuel (natural gas) and diesel. The energy producers are described in detail below.

3.4.1 Boilers

The present model considers conventional natural gas fired boilers to generate process steam at 6,300kPa, 500ºC. This type of steam is used for: conditioning, diluted bitumen extraction and upgrading. The total cost associated with the production of process steam (S_{TC}) in this type of boiler (SB) is calculated as follows:

$$S_{TC} = t\left(\frac{1}{EC}\left(NSB\ \ NGSB\ \ CS\ \ HVNG\ \ PNG\right) + SD\,CFW\right) \tag{36}$$

where $NGSB$ is the consumption of NG per boiler (Nm^3/h), NSB is the number of boilers selected by the model to produce process steam, CS is the percentage of the boiler capacity used to generate steam (82%), $HVNG$ is the heating value of NG (38.05 MJ/Nm^3), PNG is the price of NG, *SD* (equation 34) is the total amount of steam (tonne/hr) produced by the boilers, *CFW* is the cost of the boilers feed water, *t* is the annual operating hours (8,760 h/year), and *EC* is an energy conversion factor (1,000 MJ/GJ).

Hot water is used in conditioning, hydrotransport and diluted bitumen extraction. The proposed model assumes that the capacity of the boilers is used to produce process steam and hot water. The total cost of hot water (HW_{TC}) is calculated as follows:

$$HW_{TC} = t\left(\frac{1}{EC}\left(NSB\ NGSB\left(1-CS\right)HVNG\ PNG\right) + HWD\ CFW\right) \tag{37}$$

where *HWD* (equation 35) is the amount of hot water (tonne/hr) produced in the boilers (SB). The present model also includes boilers that produce SAGD steam at 8,000kPa, 80% quality (SSEB). SAGD steam's cost (SSE_{TC}), used only for in-situ bitumen extraction, is calculated as follows:

$$SSE_{TC} = t\left(\frac{1}{EC}\left(NSEB\ NGSEB\ HVNG\ PNG\right) + SSE\ CFW\right) \tag{38}$$

where *NGSEB* is the consumption of NG per boiler (Nm^3/h), *NSEB* is the number of boilers producing SAGD steam, and *SSE* is the amount of SAGD steam produced in the boilers (see equation 9). The installed capacity of the boilers considered in the model is 340 tonne of steam per hour [24]. The capital cost of the boilers is not considered in this model given that it can be neglected when compared to its annual fuel consumption cost. The boilers were modeled using information available in the literature [24].

3.4.2 Hydrogen Plants

The present model considers steam methane reforming (SMR) and gasification as the technologies for hydrogen production. The SMR plants considered in this model are based on previous studies [37, 38]. The model assumed SMR hydrogen plants without CO_2 capture and with CO_2 capture. The gasification plants were modeled using data from different sources [39, 40]. The hydrogen producers in this model also include gasification plants without CO_2, and with CO_2 capture. The total cost to produce hydrogen with the two technologies can be estimated as follows:

$$H_{TC} = \sum_{j=1}^{J} NHP_j \left(ACC_j + OMC_j\right) + \frac{t\, F_j\, FHV_j\, FC_j}{EC} \tag{39}$$

where NHP_j represents the number of plants type *j* considered in the model. ACC_j is the annual capital cost of the hydrogen plant type *j* ($/yr), OMC_j is the annual operation and maintenance cost for plant type *j* ($/yr), F_j is the fuel consumed by plant (NG in Nm^3/h or coal in kg/h), FHV_j is the fuel heating value (NG= 38.05 MJ/Nm^3 or coal= 24.05 MJ/kg), and FC_j the fuel cost ($/GJ) for a plant type *j*. Equation (39) is related to the total hydrogen demand as follows:

$$H_U = \sum_{j=1}^{J} \frac{F_j\, FHV_j}{HR_j} \tag{40}$$

where H_U is the total hydrogen demand (see equation 21), and HR_j is the heat rate required to produce one tonne of H_2 (MJ/tonne H_2) per hydrogen plant of type *j*. The annual capital cost (ACC_j) of each type of plant is calculated as follows:

$$ACC_j = HPIC_j\, PCC_j\, ACF_j, \quad j = 1...J \tag{41}$$

where the annual capital cost is a function of the plant installed capacity $HPIC_j$ (tonne H_2/h), the plant capital cost PCC_j (($) (h) /tonne H_2), and ACF_j, which is an amortized capital factor given in a percentage form. The annual operation and maintenance cost (OMC_j) of each type of plant is calculated as follows:

$$OMC_j = HPIC_j\, PCC_j\, OMF_j, \quad j = 1...J \tag{42}$$

where OMF_j is an operation and maintenance economic factor given in percentage form.

3.4.3 Power Plants

The present model considers integrated gasification combine cycle (IGCC), oxyfuel, natural gas combine cycle (NGCC), and supercritical pulverized coal (SCPC) to generate power for the Oil Sands operations. These plants were modeled following reports published in the literature [28], [41, 42]. Three CO_2 capture methods are considered in the model: pre-combustion, post-combustion and oxy-combustion. The IGCC power plants considered in the model use coal as feedstock. The model considers IGCC plants without CO_2 capture, and with CO_2 capture. Likewise, the oxyfuel plants included in the model are: Natural gas and coal with CO_2 capture. Moreover, the model considers NGCC plants without CO_2 capture and with CO_2 capture. Furthermore, there are two SCPC plants included in the model: SCPC without CO_2 capture, and with CO_2 capture (see Table 2-2). The total cost for power generation by the fleet (P_{TC}) is formulated as follows:

$$P_{TC} = \sum_{m=1}^{M} NPP_m \left(ACC_m + OMC_m \right) + \frac{t\, PG_m\, HR_m\, FC_m}{EC} \tag{43}$$

where NPP_m represent the number of power plants type m, ACC_m the capital cost of the plant type m, OMC_m the annual operation and maintenance costs, PG_m the power generated by the plant (kW), HR_m the heat rate by plant (MJ/kWh), and FC_m the fuel cost (natural gas and coal). Equation (43) is related to the total power demands as follows:

$$\begin{aligned} PD &= \sum_{m=1}^{M} PG_m + \sum_{j=1}^{J} HPG(j)\, PG_j \\ HPG(j) &= \begin{cases} 1 & \text{if hydrogen plant } j \text{ is type Gasification} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \tag{44}$$

where PD (see equation 33) is the total power required in the model (kW), and PG_j is the power co-generated in gasification hydrogen plants (kW). The annual capital cost of the power plants (ACC_m) is calculated as follows:

$$ACC_m = HPIC_m\ PCC_m\ ACF_m \quad ,m=1...M \tag{45}$$

where the annual capital cost is a function of the plant installed capacity $HPIC_m$ (kW), the plant capital cost PCC_m (\$/kW), and ACF_m an amortized capital factor given in percentage form. Although every energy producer considered in the model includes an installed capacity (constant parameter), the operating condition (OC) is a decision variable within the optimization formulation (see equation 51). The annual operation and maintenance cost (OMC_m) for each type of plant is calculated as follows:

$$OMC_m = HPIC_m\ PCC_m\ OMF_m, \quad m=1...M \tag{46}$$

where OMF_m is an operation and maintenance economic factor given in percentage form.

3.5 Additional Costs and Outputs

The present model assumes that the diesel and process fuel feedstock are supplied by external providers. As shown in equation (47), the total cost of diesel (D_{TC}) is calculated from the total fuel diesel demand, D (see equation 8), and the cost of the diesel (CD). Similarly, the total cost of process fuel demand (PF_{TC}) in equation (48) is a function of the total process fuel consumption, PF_U (see equation 29).

$$D_{TC} = D\ CD\ t \tag{47}$$

$$PF_{TC} = \frac{t\ PF_U\ \ HVNG\ \ PNG}{EC} \tag{48}$$

The costs associated with the transport of the CO_2 captured in power and hydrogen plants are calculated as follows:

$$CTC = \left(\sum_{j=1}^{J} HPC(j)\ CCH_j + \sum_{m=1}^{M} PPC(m)\ CCP_m \right) (t \ \ UCTC\ PL) \tag{49}$$

where the sub-indexes *j* and *m* represent the type of hydrogen and power plants, respectively. *CTC* is the total annual CO_2 transport cost ($/year) whereas CCH_j and CCP_m are the total amounts of CO_2 captured in hydrogen and power plants (tonne CO_2/h), respectively. *UCTC* is the unitary CO_2 transport cost ($ 0.014/tonne CO_2/Km), and *PL* is the length of the pipe used to transport the CO_2 from Fort McMurray to depleted oil fields nearby Edmonton (≈600 Km). The annual carbon dioxide storage cost (*CSC*) is calculated as follows:

$$CSC = t \ \ UCSC \left(\sum_{j=1}^{J} HPC(j)\ CCH_j + \sum_{m=1}^{M} PPC(m)\ CCP_m \right) \tag{50}$$

where *UCSC* is a parameter representing the carbon dioxide underground injection cost.

3.6 Optimization Model

The inputs, the bitumen and SCO production schemes, the energy demands, and the energy producers discussed in the above sections are embedded within an optimization formulation that minimizes the energy production costs for this process. The model proposed in this work minimizes the energy production costs instead of maximizing a profit. This is because the latter would imply the need to set a price on the SCO and commercial bitumen. Recently, the energy market has experienced changes due to unexpected events, e.g., global economic crisis, political conflicts on important oil producer regions, climate change issues. These factors have caused large and quick fluctuations on the oil prices which would lead to forecast values highly sensitive to these prices and significantly reduce the accuracy of the results in a profit maximization model. Thus, the optimization model considered in this work is formulated as follows:

$$\min_{\eta} \quad CF = P_{TC} + H_{TC} + S_{TC} + SSE_{TC} + HW_{TC} + PF_{TC} + D_{TC} + CTC + CSC \tag{51}$$

$$\begin{array}{lll}
st & \text{Total Energy Demands} & \text{(equations: 8–9, 21, 29, 33–35)} \\
 & \text{Production Schemes} & (OPS_i) \\
 & \text{Production levels} & \text{(equations 5)} \\
 & \text{Energy Producers} & \text{(equations 36–46)} \\
 & \text{Energy Producers Installed Capacities} & \\
 & \text{Environmental Constraint} & \text{(equation 4)} \\
 & \text{Where} \quad \eta = \left[OPS_i, SO_i, NSB, NSEB, NHP_j, NPP_m, OC\right] &
\end{array}$$

where *CF* is the model's cost function that is minimized in the energy model. This function (*CF*) represents the energy costs involved in the production of commercial bitumen and SCO. The cost function is given in terms of a yearly cost (US \$ (2007) /year). Moreover, the model's cost function (*CF*) includes the annual production costs of power (P_{TC}), hydrogen (H_{TC}), process steam (S_{TC}), SAGD steam (SSE_{TC}) and hot water (HW_{TC}). Additionally, *CF* includes the annual supply costs of process fuel (natural gas) used in the upgrading stage and diesel fuel (D_{TC}) for mining activities in the operation. Also, *CF* includes the annual costs associated to carbon capture and storage systems, i.e., CO_2 transport cost (*CTC*) and CO_2 storage cost (*CSC*). Furthermore, η represents the set of decision variables specified by the production schemes (OPS_i), the schemes production levels (SO_i), the number of process steam boilers *(NSB)*, the number of SAGD steam boilers (*NSEB*), the number of hydrogen plants type *j*, (NHP_j), the number of power plants type *m* (NPP_m), and *OC* the energy producers' operating conditions, i.e., boilers and plants capacity. The optimization model searches for the most suitable combination of production schemes (type of schemes and production levels) and the energy producers (numbers and capacities) that minimize the energy production costs of the Oil Sands operation while meeting a user-defined environmental constraint, i.e., CO_2 emission target, which is introduced in the model as a constant parameter that represents the CO_2 emission goal for a given oil production scenario. This environmental constraint can be defined in the energy model according to governmental plans, e.g., Turning the Corner [15], or international agreements such as the Kyoto Protocol of the United Nations Framework Convention on Climate Change [13, 14]. The present energy model only accounts for CO_2 emission target as environmental constraint in the formulation. Although there are other environmental metrics associated to the Oil Sands operations, e.g., water management, additional GHG emissions (CH_4, N_2O) and tailing ponds generation, the carbon dioxide emissions currently represent the major environmental issue in the operation of the Oil Sands industry since CO_2 accounts for 85-95% of the total enhanced global warming effect [13]. However, environmental metrics such as water management and tailing ponds generation have gained public interest in recent years. Water management is thought to play an important role in the expansion of the Oil Sands industry. This is because there are concerns about the availability of freshwater from the Athabasca River to sustain further increase of the oil operations in Alberta for the medium term future [43, 44].

The proposed integrated model is a mixed integer nonlinear program (MINLP) because it considers integer variables, i.e., the optimization model selects the type and number of boilers, hydrogen and power plants (NSB, $NSEB$, NHP_j, NPP_m) required to maintain the Oil Sands operations. Also, the model included binary variables, e.g., the SCO production schemes, OPS_1-OPS_7 (see Table 2-1). Moreover, the model considers continuous variables, e.g., mass and energy balances from processing stages involved in the schemes. Examples of continuous variables in the model are: the reduction of CO_2 emissions needed to meet the CO_2

emission target (CCO_2) (4), the hydrogen consumption in hydrotreatment (H_{HT}) (20), the total cost of diesel (D_{TC}) and process fuel (PF_{TC}) (47-48), and the cost objective function (*CF*) (51). The model was developed in the General Algebraic Modeling System (GAMS) [45]. GAMS is a high level modeling system that is used for mathematical programming and optimization. GAMS was selected for the present work because it features a few advantages when compared to other programming systems, e.g. MATLAB, Maple and Fortran. GAMS' main features are as follows: 1) the model's formulation is done through concise algebraic statements that is user friendly, 2) sets of constraints and equations can be easily created in a very efficient fashion, 3) the models can be built independently of the algorithms that can be used to solve the programming problem, 4) sensitivity analysis can be efficiently done for the input parameters considered in the programming formulation, 5) it includes advance features to solve large models, e.g., large-scale nonlinear programming solver as CONOPT, and 6) it has several built in features that allow solving dynamic models with minimum programming complexity.

In GAMS, the model that needs to be developed is written first in the programming platform. The user then selects the solver(s) that will be used to solve the formulated problem, e.g., the user can set the type of solver use by the platform to solve the individual linear programs (LP), nonlinear programs (NLP) and mixed integer (MIP) programs that are part of a complex problem. GAMS compiles the mathematical formulation and solves the problem. GAMS includes several special functions that allow the user to reference sets, represent time, define conditions, withdraw information on internal matters, make sets of mathematical operations, make trigonometric calculations, etc. GAMS was selected in this work because some of the models previously developed on this area were also formulated using GAMS [7, 8]. The energy model was solved executing the Discrete and Continuous Optimizer (Dicopt) as solver, which is based on the outer-approximation algorithm [46]. Dicopt is a solver used for mixed-integer nonlinear programs (MINLP) problems that involve linear binary or integer variables and linear and nonlinear continuous variables. The MINLP algorithm inside Dicopt solves a series of NLP and MIP sub-problems that can be solved using any nonlinear (NLP) or mixed integer program (MIP) solver that works under the GAMS system. The algorithm inside Dicopt first solves the NLP considering the conditions of the binary variables relaxed. Then, if the solution to the problem yields an integer solution the search stops. Otherwise, Dicopt continues solving sequence of NLP called subproblems and MIP identified as the master problems. The subproblems are solved for fixed variables (0-1) projected by the master problems at each (major) iteration until the solver finds the most suitable solution or when the subproblem starts worsening with respect to a previous feasible solution.

The integrated energy model features a new spectrum of possibilities to evaluate, plan and schedule the upcoming Oil Sands operations. The main feature of the present integrated energy model over previous models developed for the Oil Sands Operation [6-8] is that it considers the production schemes (OPS_i) and the SCO production levels (SO_i) simultaneously as decision variables within the optimization formulation. This expands the energy producers' feasible region to search for a combination in the energy producers' infrastructure that can satisfy the total energy demands for the Oil Sands operation at a lower cost than that reported by the previous studies [6-8]. Thus, the present model may return a more economically attractive infrastructure for the Oil Sands Operations. Also, the present model can be used as a practical tool to determine the energy production costs for the Oil Sands operations, generate future production schemes and energy demands scenarios, also identify the key parameters that may directly affect the Oil Sands operation. Figure 3-2 shows the integrated optimization model layout.

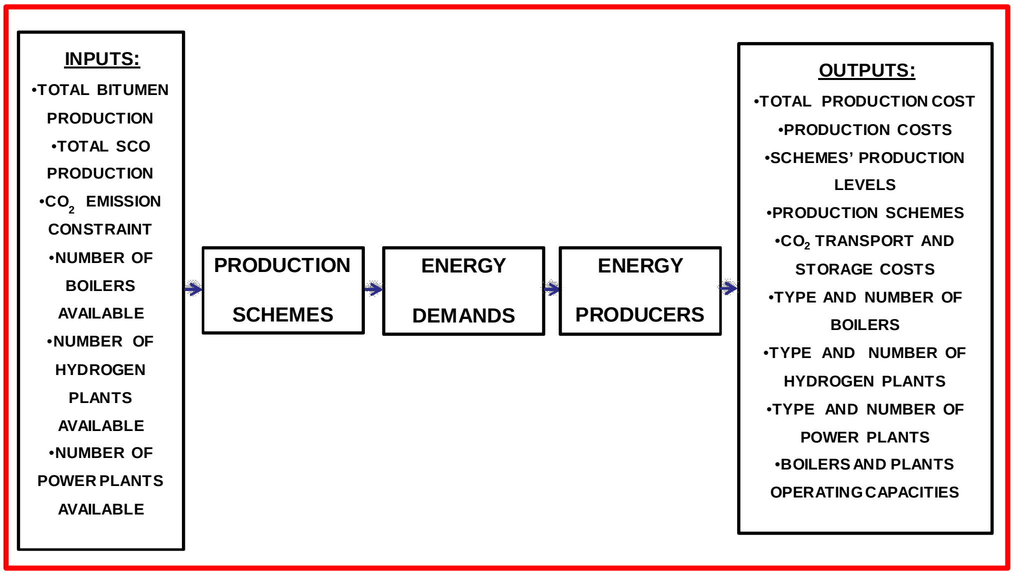

Figure 3-2. Integrated model Layout

Chapter 4

4 Results and Discussion

This section presents the application of the integrated energy model presented in the previous section to assess the operations of the Oil Sands operations for 2003 and 2020, respectively. The 2003 case study was used to validate the present integrated energy model. Results that show the benefits of using an integrated approach over a sequential modeling approach, like those used in previous modeling studies, are also discussed on this chapter. The second part of this section presents the application of the present energy model to evaluate the Oil Sands operations for year 2020. To analyze the environmental effects on the Oil Sands operation, this 2020 case study was solved with and without CO_2 environmental restrictions. Trade-offs regarding the environmental constraint for year 2020 are discussed at the end of this chapter.

4.1 Case Study 2003

The first step considered in the present study was to validate the proposed energy model for the Oil Sands. Thus, the optimization model described in the previous section was initially used to simulate the Oil Sands operation in 2003. The year 2003 was selected in this study because information regarding the 2003 production levels for the Oil Sands operations is available in the literature [47]. Also, a study that shows the energy demands for the specific production schemes and their corresponding production levels for 2003 is available in [7]. In addition, the unit cost per barrel of SCO and commercial bitumen produced in 2003 has been reported in the literature [48].

According to the information available in the literature, the present optimization modeling tool was validated for a specific production scenario, i.e., fixed OPS_i (see Table 2-1, OPS_1-OPS_4) and SO_i (see equation 5, SO_1-SO_4), respectively. Integrated Mining/Upgrading production schemes were the only schemes considered in this case study. Thus, the number of production schemes (*N*) was set to 4. Similarly, the potential benefits of using an integrated model were analyzed for this case study by assuming that only the total SCO and bitumen productions are given as inputs. That is, the integrated approach proposed in energy model's formulation was used to obtain the most suitable oil and energy producer's infrastructure that minimizes the fleet's energy costs for 2003. A list of the key inputs for the 2003 case study is listed in Table 4-1.

Table 4-1. Key inputs for Case Study 2003

Parameters[c]	Units	Value
Boiler feed water cost	\$/tonne	1.5
Natural gas cost	\$/GJ	5.8
Diesel cost	\$/l	0.7
Natural gas heating value	MJ/Nm^3	38.05
Heat for process steam (SB)	MJ/tonne steam	3,415
Heat for SAGD steam (SSEB)	MJ/tonne steam	2,469
Boiler capacity	tonne steam/h	340
Annual operating hours	h/yr	8,760
Plant capacity factors	%	0.90

[c]SB = Natural gas boilers for process steam at 6,300 kPa and 500 ºC,
SSEB = Natural gas boilers for SAGD steam at 80% quality and 8,000 kPa.
Note: Costs are express in US \$ (2003) for this case study.

For the present case study, SMR hydrogen plants and NGCC power plants without CO_2 capture were considered as the only hydrogen and power plants available in the model, which corresponds to a BAU scenario (see Table 2-2), i.e., HP_1, $J=1$ and PP_1, $M=1$. This was done to mimic the conditions for hydrogen and power production in 2003 [7] (see Table 4-2 for energy plant details).

Since the energy producers considered for 2003 do not account for CO_2 capture, the CO_2 capture constraint shown in the integrated optimization model (see equation 4 and 51) was not considered in the optimization formulation for this case study. Hence, the costs associated with the CO_2 capture that appear in the model's objective function shown in equation (51), i.e., CO_2 transport costs (*CTC*) and storage costs (*CSC*), were set to zero for the present analysis. Furthermore, the present case study assumed that the only process fuel considered for heating during upgrading was natural gas. Likewise, the shovels and trucks fleets used for mining the oil sand are composed of 4 and 5 different models, i.e., $K=4$ and $L=5$, respectively.

Table 4-2. Energy producers modeling factors

Energy Producer	Installed Capacity	Heat Rate	Capital Cost	Operation and maintenance economic factor
Power plants	(kW)	(MJ/kWh)	($/kW)	(% Capital cost)
PP_1	507,000	7.17	570	0.018
PP_2	524,000	9.16	1,230	0.038
PP_3	539,000	8.76	1,760	0.026
PP_4	448,000	11.06	2,400	0.025
PP_5	513,000	10.17	1,890	0.026
PP_6	432,000	8.41	930	0.037
PP_7	492,000	12.04	1,980	0.049
PP_8	440,000	7.70	1,250	0.086
PP_9	532,000	9.72	1,950	0.076
Hydrogen plants	(tonne/h)	(MJ/tonneH_2)	(MM$)(h)/tonne$H_2$	(% Capital cost)
HP_1	6.25	174,900	11,130	0.060
HP_2	32.09	209,000	23,780	0.036
HP_3	6.25	204,200	17,760	0.060
HP_4	32.09	209,000	25,070	0.036
HP_5	32.09	209,000	23,400	0.036

Note: HP_2 and HP_4 cogenerate 2,240 and 1,210 kWh/tonne H_2, respectively.

4.1.1 Model Validation

To validate the model proposed in this work, the production schemes and their corresponding production levels, i.e., OPS_i and SO_i, were specified *a priori* and represent inputs into the model. This approach, referred to from thereafter as the *sequential mode*, only selects the energy infrastructure (energy plants) and their corresponding operating capacities that minimize the annual energy production costs of the Oil Sands for specific settings in the production schemes. Figure 4-1 shows the general layout for the sequential mode. As shown in the Figure, the energy demands in the sequential mode remain fixed during the optimization. Therefore, the sequential model searches for the configuration in the energy producers and their corresponding operating conditions that minimizes the energy costs.

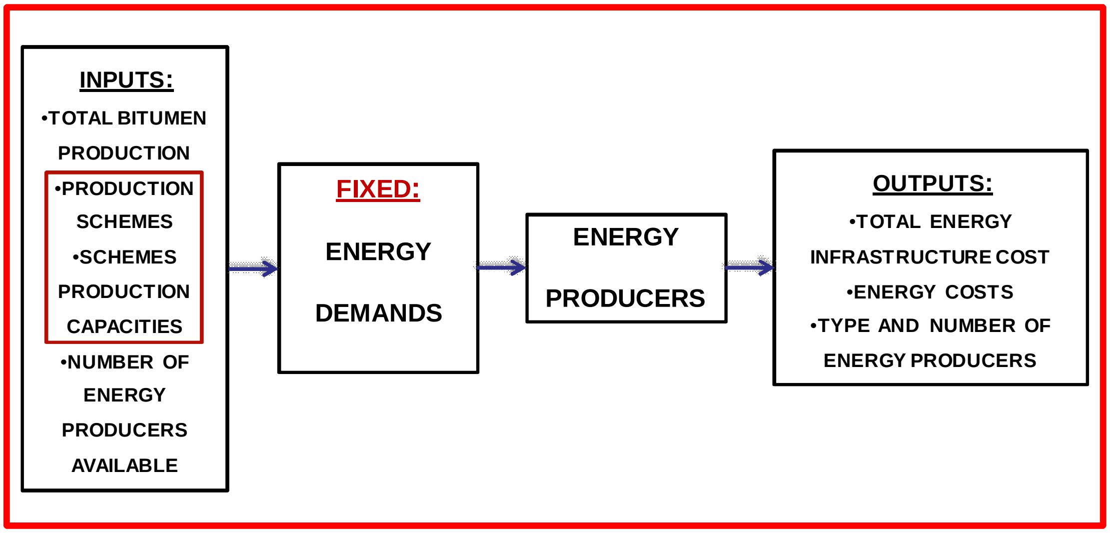

Figure 4-1. General Layout for the sequential mode

The values for OPS_i and SO_i for 2003 were obtained from the literature (baseline emission scenario) [47]. Table 4-3 shows the infrastructure of the energy commodity producers obtained for the model validation (Sequential mode). Similarly, The model validation results regarding the SCO production schemes, the energy commodity demands and the annual costs are shown in Table 4-4 (Sequential mode). The 2003 energy demands and the energy producers' infrastructure obtained with the sequential mode match with those reported in a previous study [7].

Table 4-3. Energy producer's infrastructure for Case Study 2003

	Ordorica et al. [7]		**Sequential Mode**		**Integrated Model**	
Energy Producer	Number of unit	Capacity	Number of unit	Capacity	Number of unit	Capacity
PP_1	2	319,323 kWh	2	319,320 kWh	1	323,570 kWh
HP_1	13	5.52 tonne/h	13	5.52 tonne/h	13	5.27 tonne/h

Table 4-4. Simulation results for Case Study 2003

Variables[d]	Units	Ordorica et al. [7][e]	Sequential	Integrated
Production Schemes				
OPS_1	tonne oil sand	152,469,006	152,469,006	1,238.79
OPS_2	tonne oil sand	45,291,746	45,291,746	841.04
OPS_3	tonne oil sand	46,748,957	43,900,129	308,200,000
OPS_4	tonne oil sand	108,347,364	108,347,364	1,216.19
OPS	tonne oil sand	352,857,073	350,008,245	308,203,296
	bbl SCO/d	538,000	538,200	538,200
DB	bbl/d	350,000	350,000	350,000
Energy demands				
Power	kWh	638,645	638,640	323,570
Steam	tonne/h	3,088	3,088	3,271.02
Hot Water	tonne/h	28,462	28,462	24,987.82
Diesel	l/h	43,486	43,486	38,313.23
Hydrogen	tonne/h	71.8	71.77	68.51
Process fuel (NG) for DC	Nm^3/h	26,150	25,103	0.20
Process fuel (NG) for LCF	Nm^3/h	8,305	8,325	7,286.37
Annual costs				
Capital	MM $/yr	n/a	130.2	105.08
Operating and	MM $/yr	n/a	49.09	39.62
Fuel	MM $/yr	n/a	2,809.83	2,625.93
Water	MM $/yr	n/a	496.52	521.58
Total Cost	MM $/yr	n/a	3,485.64	3,292.2

[d]OPS = Total oil sand mined, DB = Total diluted bitumen production.
[e]n/a = Not applicable because the data was not reported in [7].

Comparing the results previously shown in Tables 4-3 and 4-4 that were obtained by Ordorica et al. [7] and those obtained in this work to validate the energy model (Sequential), the s*equential* mode agrees reasonably well with the results reported in the literature [7]. The comparison was done using the same model's constraints considered by Ordorica et al. [7], i.e., fixed oil production schemes and capacities according to historical data of the Oil Sands productions from the year 2003, only NGCC power plants and SMR hydrogen plants without capture were available in the optimization problem. One of the key parameters in the current optimization model is the natural gas price. The present case study assumed that the energy producers only used natural gas as fuel. Also, natural gas was assumed to be the only process fuel in the upgrading stage for heating purposes. Thus, the costs associated with natural gas consumption are expected to have a significant effect on the model's cost function. As shown in Figure 4-2, the natural gas prices for Alberta in 2003 fluctuated between a minimum of $ 4.60 and a maximum of $ 8.94 with an average cost of $ 5.80 [49].

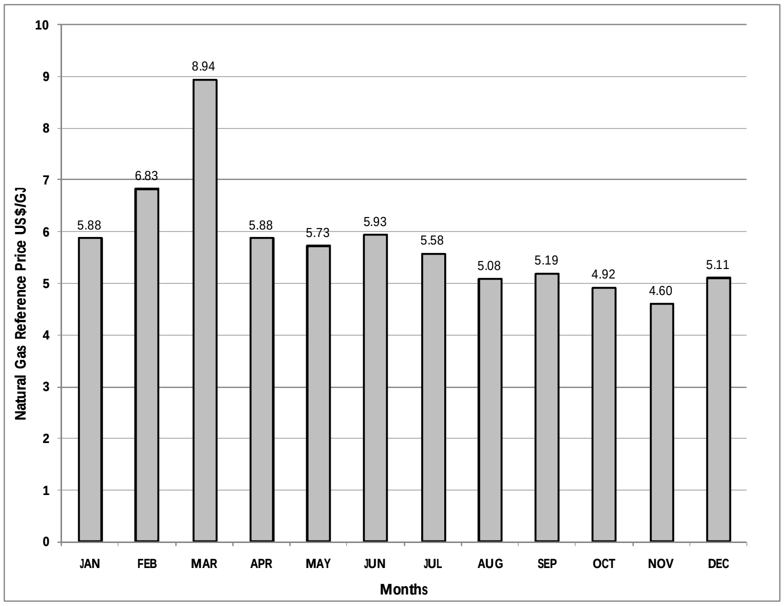

Figure 4-2. Alberta natural gas reference price history for 2003 [49]

To evaluate the significance of the natural gas price on the unit production costs of SCO and bitumen, the proposed (sequential mode) model was simulated using different natural gas prices for 2003. The selected natural gas price range goes from the lowest price up to the highest recorded price in that year. Figure 4-3 shows the sensitivity analysis results obtained from the optimization model and the historical gas price data [49] for the SCO production costs for 2003, respectively. As shown in the Figure, the predictions on the unit cost of SCO for integrated Mining/Upgrading production schemes (see Table 2-1 OPS_1-OPS_4) agree reasonably well with the historical data reported in the literature [48]. Figure 4-3 also shows the unit cost of SCO corresponding to the average natural gas price and its standard deviation. As shown in this figure, the model predicts that these costs are within the range of values reported for the price per barrel of SCO produced in 2003 ($ 9-$ 13.5). Although the unit costs for the SCO production that corresponds to the maximum value in the natural gas price is outside the range reported in the literature, that value was considered as rare in the NG prices for 2003 and is not representative of the natural gas prices for 2003 (see Figure 4-2).

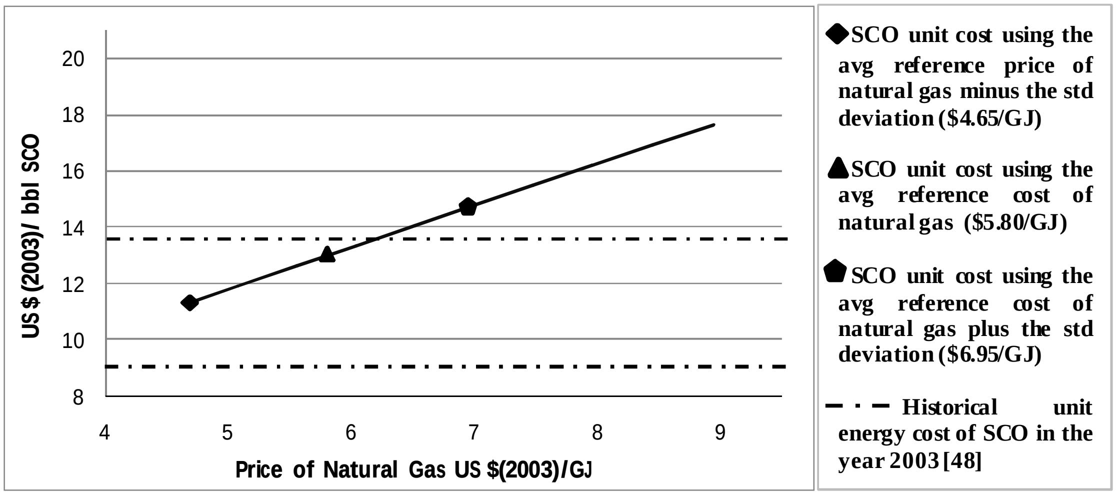

Figure 4-3. Influence of Alberta's natural gas price over SCO unit production cost for 2003

A similar sensitivity analysis was made for the commercial diluted bitumen production. The results shown on Figure 4-4 suggest that the unit production costs per barrel of bitumen produced obtained by the proposed model agrees with the range of unit costs reported for 2003 [48]. Figure 4-4 also shows the unit costs for the bitumen when the average value and their corresponding standard deviation were used in the model for this case study.

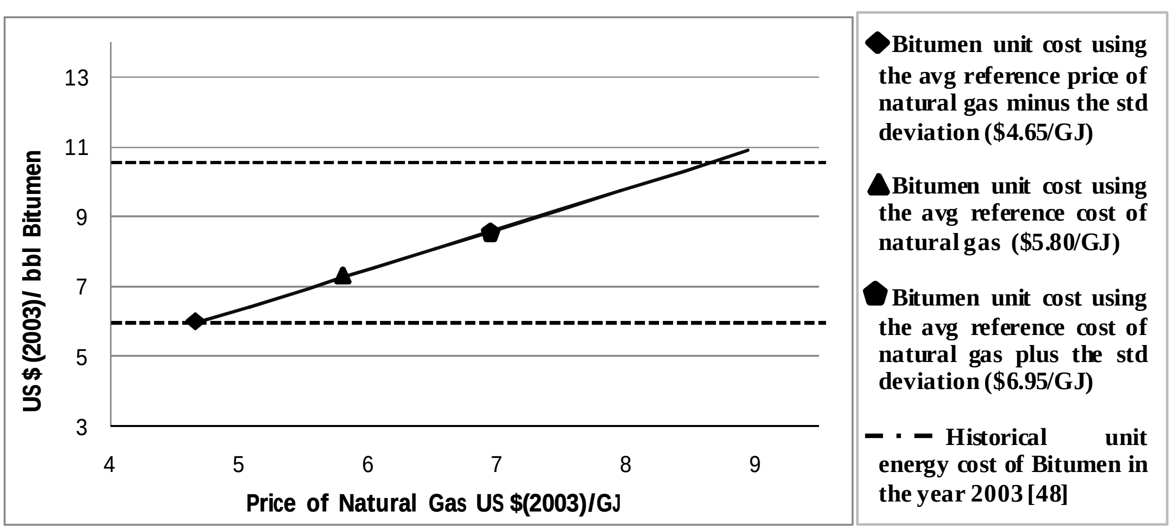

Figure 4-4. Influence of Alberta´s natural gas price over bitumen unit production cost for 2003

Table 4.5 shows the comparison between the historical energy production costs for commercial bitumen and SCO and those obtained by the sensitivity analysis from the sequential mode of the optimization model using recorded gas price data for the year 2003 [49].

Table 4-5. Unit energy production costs for commercial bitumen and SCO for Case Study 2003

	Commercial Bitumen		Mined SCO	
Energy Production Costs (US $ 2003/bbl)	Historical Data [48]	Sequential Mode Results	Historical Data [48]	Sequential Mode Results
High	10.5	8.60	13.5	14.72
Reference	n/a	7.28	n/a	13.0
Low	6.0	5.96	9.0	11.3

Based on the above, the results obtained with the proposed optimization model agree reasonably well with those reported in a previous study [7] and with historical data reported for the Oil Sands for 2003 [48]. Therefore, the present energy optimization model proposed in this study can be used to predict the energy production costs associated to potential scenarios in the future for the energy demands and the energy infrastructure for the Oil Sands. Although the historical energy costs per barrel of oil produced for the year 2003 are similar to those predicted by the model, the above results do not correspond to an optimal energy infrastructure because only NGCC power plants and SMR hydrogen plants were considered for this scenario according to the information reported in the literature [6, 7]. The optimal energy infrastructure is considered in the case studies addressed in the next sections.

4.1.2 Simulation of the integrated model for 2003

To illustrate the potential benefits of using the proposed integrated model, the 2003 case study was redone assuming that the total diluted bitumen (*TDB*) and SCO production (*TSCO*) are the only inputs defined in the model. That is, the production schemes (OPS_1-OPS_4) and their corresponding production levels (SO_1-SO_4) are selected by the optimization algorithm.

This represents a main advantage with respect to the sequential mode since the present model simultaneously selects the most suitable production schemes and energy producers that need to be used to minimize the total energy costs for the Oil Sands operations. Therefore, OPS_i and SO_i are treated as decision variables within the optimization model. The optimization results obtained with the sequential mode were used as the initial guesses for this simulation. In this particular scenario, the optimization algorithm searches for combinations in the production schemes, their corresponding levels of operation, the energy infrastructure and their corresponding operating conditions that minimize the energy costs for the 2003 SCO and diluted bitumen productions. This scenario for the 2003 case study was solved using the MINLP solver DICOPT through the GAMS modeling system. The MINLP algorithm inside DICOPT solves a series of NLP (Nonlinear Programming) and MIP (Mixed Integer Programming) sub-problems. These sub-problems were solved using MINOS and CPLEX as NLP and MIP solvers, respectively. MINOS is based on an augmented Lagrangian objective function and the CPLEX algorithm is based on an implementation of a branch and bound search. The proposed optimization problem considered for this scenario consists of 688 variables, i.e., continuous, integer and binary variables. For example the integer variables in the model are represented by the number of process steam boilers (*NSB*), SAGD steam boilers (*NSEB*), hydrogen plants (NHP_1) and power plants (NPP_1). The SCO production schemes, OPS_1-OPS_4 (see Table 2.1) are examples of binary variables in the present model's formulation.

Table 4-4 (Integrated model) shows a summary of the results obtained by the integrated model for 2003. As shown in the Table, the integrated model returned a solution that is more economically attractive than that proposed by the sequential mode. The integrated model returned energy savings that are 5.6% (193.4 MM $) higher than those obtained by the sequential mode. Also, the average cost per barrel of SCO produced was reduced from $ 13/bbl to $12/bbl (7.7% cost reduction). On the other hand, the cost of the bitumen produced remained constant ($ 7.28/bbl). This is because only one production scheme was considered in this case study for commercial diluted bitumen production. Thus, the model is forced to select that production scheme to meet the oil demands for this commercial diluted bitumen production. Figure 4-5 shows a comparison between the production schemes selected by the integrated model and the production schemes reported for 2003 that were used for the model validation using the sequential mode approach.

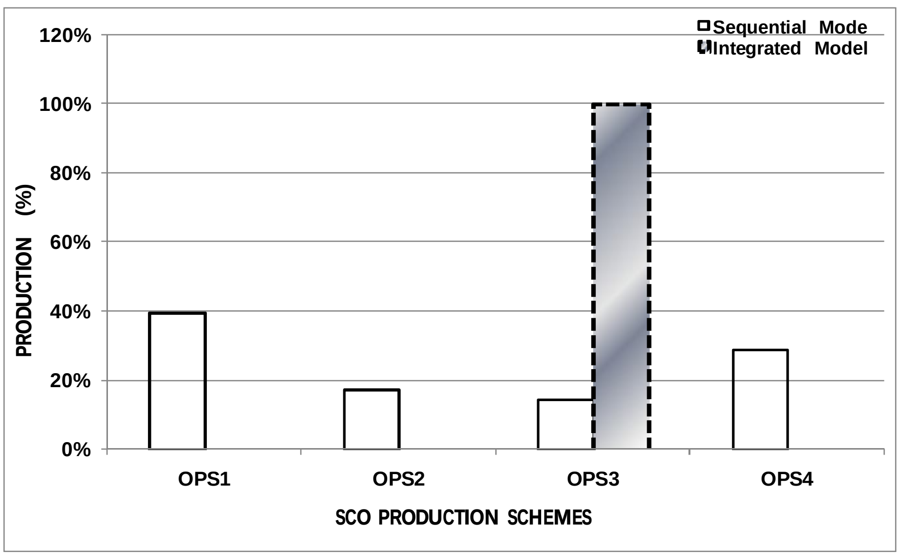

Figure 4-5. Comparison of SCO schemes between the sequential and integrated model for 2003

As shown in this Figure, OPS_3 (see Table 2-1 for details on the production schemes i.e., OPS_i) is the only and preferred SCO production scheme selected by the integrated model. The term *being selected* by the energy model means that the solution of the optimization returned values for that model's variable. These results suggest that the production schemes that include a combination between thermal cracking and hydrocraking (Fluid Coking and LC-Fining) are the most suitable to be selected than those that only use thermal cracking (OPS_1, Delayed Coking) or hydrocracking (OPS_2). Although, OPS_4 is based on a combination of thermal and hydro-cracking technologies (Fluid Coking and LC-Fining) like OPS_3, the OPS_4 combination of conditioning and hydrotransport stages is less energy efficient than treating the total mined oil sand by hydrotransport (scheme OPS_3) because conditioning requires larger amounts of hot water per tonne of oil sand processed than that used in hydrotransport. Accordingly, 0.33 tonne of water/tonne of oil sand are required in conditioning whereas hydrotransport requires 0.30 tonne of water/tonne of oil sand. In addition, conditioning demands process steam which is not required in hydrotransport for treating the mined sand, i.e., 0.036 tonne of steam/tonne of oil sand. Thus, higher costs may be expected from OPS_4 since higher energy requirements are needed for the conditioning stage. OPS_3 was the most optimal solution for the SCO production scheme because it returned the totality of SCO produced for this case study. In addition, OPS_4 consumes steam, which is not used in hydrotransport. Moreover, the distance considered from mining to the extraction plants is six times larger for OPS_4 than for OPS_3 (d_4= 3000 m, d_3= 500 m). Thus, the electricity requirements to pump the slurry to the extraction plant are expected to be higher for OPS_4 than for OPS_3, respectively. Furthermore, OPS_4 also consumes more process fuel per barrel of SCO produced than OPS_3.These characteristics favored the selection of OPS_3 over OPS_4 for the present scenario.

The production scheme OPS_2 was not selected by the integrated model because it consumes 2.25 times more electricity than OPS_3. This is mainly because the distance between mining and the extraction plant is six times larger for OPS_2 than for OPS_3 (d_2= 3000 m, d_3= 500 m), i.e., larger energy requirements are needed for OPS_2. Also, the hydrogen demands are 1.85 times larger in OPS_2 that for OPS_3. This is because OPS_2 uses hydrocracking as the only cracking technology. This technology is highly intensive in hydrogen consumption which is produced by SMR hydrogen plants that use natural gas as feedstock. Also, OPS_2 requires 4 times more process fuel in upgrading than OPS_3. Note that the only process fuel considered in the present case study is natural gas. As discussed above in section 4.1.1 (Model Validation), natural gas is one of the most influential factors that affect the total energy production cost of commercial crude bitumen and SCO in the model.

The production scheme OPS_1 was not selected because it consumes 1.25 times more hot water per barrel of SCO produced than OPS_3. Although the hot water requirements per tonne of oil sand processed are the same for both schemes, the output (bbl of SCO) from OPS_3 scheme per tonne of oil sand processed is greater than OPS_1, which makes OPS_3 a more efficient scheme. Also, the electricity demands are 2.3 times higher in OPS_1 when compared to OPS_3 mainly because the distance from the mining site to the extraction plant is 5.8 times larger in OPS_1 (d_1= 2900 m, d_3= 500 m), i.e., pumps with larger energy consumptions are needed to transport the slurry to the extraction plant. In addition, the process fuel consumption in OPS_1 is 8.7 times larger than OPS_3 because OPS_1 uses thermal cracking as the only cracking technology. Thus, more heating is required during upgrading for this production scheme.

As shown in Table 4-4, the proposed integrated model reduced the process fuel and electricity demands by 78 % and 50% with respect to the sequential mode approach, respectively. Similarly, the hot water and diesel demands were reduced by 12% whereas the hydrogen requirement was reduced by 4.5%. Moreover, only one power plant was specified by the model to satisfy the electricity demands. This power plant is a NGCC plant which requires natural gas for the electricity supply. On the other hand, the information reported in a previous study suggests that 2 NGCC power plants were required to meet the electricity demands [7] (see Table 4-3). This difference can be attributed to the power demands reduction of 50% obtained with the present integrated optimization model.

The annual costs distribution for both the integrated and the sequential approaches are shown in Figure 4-6. This Figure shows that the fuel consumed by the production schemes and the energy producers dominate the costs for this year. Hence, the optimization algorithm focuses on these variables to minimize the cost function represented by the annual energy supply costs of the Oil Sands industry (see cost function in 52).

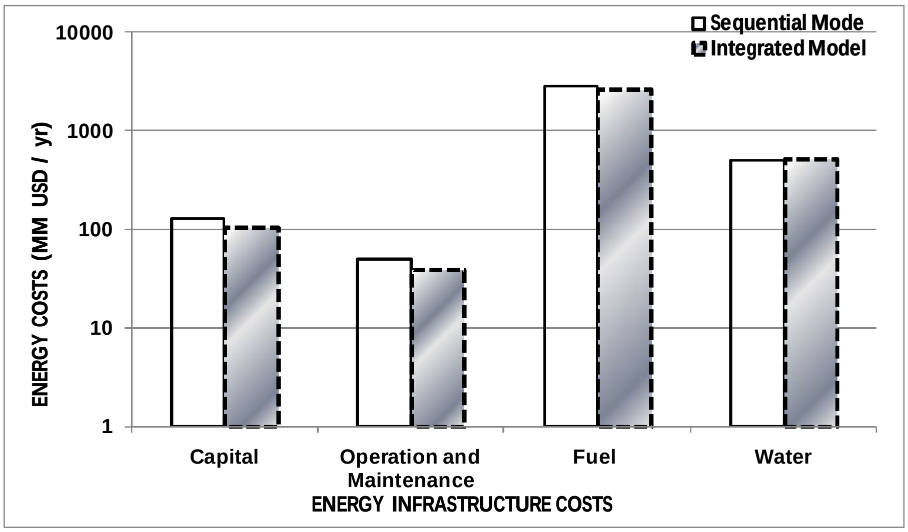

Figure 4-6. Energy costs comparison between the sequential and integrated model for 2003

The fuel cost is reduced by 6.5% when the integrated model is used. Although, the capital and the operation costs are significantly reduced (19.3%), these last two costs represent no more than 5% of the total energy costs. On the other hand, the fuel costs are roughly 80% of the total energy costs. As mentioned above, the process fuel for heating in the upgrading stage and the power demands are the two key process variables that were significantly reduced in the integrated approach because they are very sensitive to fuel consumption. The capital costs do not constitute a large contribution to the objective cost function. This is because the capital costs are amortized over the energy producers' book life (30 years). Likewise, the capital cost is distributed along this period of time and do not represent a major financial burden in the model. Water is the other significant cost due to its high consumption for steam and hot water production. Steam is commonly used for SAGD extraction, bitumen upgrading and process operations whereas hot water is mostly used for conditioning and hydrotransport.

4.2 Case Study 2020

The integrated model developed in this research was also used to determine the energy infrastructure and the potential energy costs for the operation of the Oil Sands in year 2020. This year was selected as a case study because current estimates of energy prices and economic projections with governmental programs are available in a recent report issued by the National Energy Board of Canada (NEB) [11]. Although the NEB released a report in 2007 with projections for the year 2030 [50], this report did not consider the financial crisis in the energy sector that occurred in 2008. Hence, the updated report used in this case study takes into account this unforeseeable event that changed the economic perspective and forecasts for the Oil Sands operations in the upcoming years. The key factors that affected the upcoming scenarios for the Athabasca region was the unexpected increase in the oil prices ($ 147/ barrel [11]) followed by a sudden reduction in the value of the oil ($ 60/ barrel [11]) during the early stages of the financial crisis in 2008. These factors, together with new environmental policies, have changed the global oil business perspective for the future.

Table 4-6 shows the highest, lowest and the reference SCO and bitumen productions, i.e., total SCO and bitumen production (*TSCO* and *TDB*), expected for the year 2020 in the Canadian Oil Sands.

Table 4-6. Production scenarios for Case Study 2020

Production Scenario	Unit	SCO production (TSCO)	Bitumen production (TDB)
High	bbl/d	1,647,000	1,426,000
Reference	bbl/d	1,491,000	1,291,000
Low	bbl/d	1,130,000	851,000

These production scenarios were used as inputs in the integrated optimization model to determine the most suitable combination in the production schemes and the energy infrastructures that minimize the production costs for year 2020. To propose a more realistic scenario, all the production schemes shown in Table 2-1 are considered for this case study, i.e., OPS_1-OPS_7 (N=7). Also, Table 2-2 shows all the energy producers considered to supply the energy demands for 2020, i.e., HP_1-HP_5 (J=5) and PP_1-PP_9 (M=9). Moreover, the shovels and trucks fleets used for mining the oil sand were assumed to be composed of 4 ($K=4$) and 5 ($L=5$) different models, respectively. In this first scenario considered in the present study for 2020, the CO_2 emissions were considered to be equal to those that would be obtained under a BAU scenario (see section 3.2 for details). A scenario that includes a CO_2 emission target constraint for this case study is presented in the next section.

The key economic parameters included in the optimization model for 2020, i.e., natural gas, coal, CO_2 storage and transport costs, are listed in Table 4-7. As in the 2003 case study, the resulting MINLP optimization model was coded in GAMS and solved using the MINLP solver DICOPT. This problem consisted of 896 variables, i.e., continuous, integer and binary variables. Most of the continuous variables included in the model involve the energy and mass balance equations of the oil schemes. The integer variables are given by the number of energy plants selected by the optimization model, e.g., process steam boilers *(NSB)*, SAGD steam boilers (*NSEB*), hydrogen plants (NHP_1 – NHP_5) and power plants (NPP_1 – NPP_9) (see Table 2.2). Additionally, the SCO producer schemes represents examples of binary variables in the model, e.g., OPS_1 – OPS_7 (see Table 2.1).

Table 4-7. Key inputs for Case Study 2020

Parameters	Units	Value
Boiler feed water cost	\$/tonne	1.50
Natural gas cost	\$/GJ	6.82
Coal cost	\$/GJ	0.74
Diesel cost	\$/l	1.25
CO_2 transport cost	(\$)(100 Km)/tonne CO_2	1.30
CO_2 injection cost	\$/tonne CO_2	7.0
Natural gas heating value	MJ/Nm^3	38.05
Coal heating value	MJ/Kg	24.05
Heat for process steam (SB)	MJ/tonne steam	3,415
Heat for SAGD steam (SSEB)	MJ/tonne steam	2,469
Boiler capacity	tonne steam/h	340
Annual operating hours	h/yr	8,760
Plant capacity factors	%	0.90
Boiler capacity used for steam	%	0.82

Note: Costs are express in US \$ (2007) for this case study.

4.2.1 Oil production scenarios for 2020 under BAU baseline CO_2 emission

Table 4.8 shows the results obtained for the scenarios considered for 2020 under BAU baseline CO_2 emission, i.e., production schemes and corresponding levels, energy commodity demands, annual energy costs, and unit production costs. As shown on this Table, nearly 62% of the total energy costs are represented by the hydrogen and SAGD steam generation costs. The average unitary costs are \$ 12.71, 13.32 and 5.94 for mined SCO, SAGD SCO and diluted bitumen, respectively.

The results for the present case study regarding the energy commodity infrastructure are shown in Table 4-9. As shown in the Table the hydrogen producers are coal gasification plants, the power producers are NGCC and supercritical pulverized coal power plants, and the SAGD and process steam are produced by natural gas fired boilers.

Table 4-8. Simulation results for Case Study 2020 (No CO_2 Target)

Variables	Units	Low production	Reference	High production
Production Schemes				
OPS_1	bbl/d	0	0	0
OPS_2	bbl/d	115,750	161,570	0
OPS_3	bbl/d	550,500	716,130	1,021,570
OPS_4	bbl/d	0	0	0
OPS_5	bbl/d	0	0	121,280
OPS_6	bbl/d	463,750	613,300	504,150
OPS_7	bbl/d	0	0	0
OPS	bl/d	1,130,000	1,491,000	1,647,000
DB	bbl/d	851,000	1,291,000	1,426,000
Energy demands				
Power	kWh	783,910	1,063,800	1,031,600
Steam	tonne/h	5,081	6,682	8,017
Hot Water	tonne/h	30,053	39,521	47,421
SAGD steam	tonne/h	20,557	29,836	32,767
Hydrogen	tonne/h	180.1	238.26	240
Process fuel (NG)	Nm^3/h	39,522	52,576	56,046
Diesel	l/h	46,079	60,597	72,709
Annual costs				
Power	MM \$/yr	224.91	381.28	379.31
Hydrogen	MM \$/yr	1,907.80	2,460.20	2,462.20
Hot Water	MM \$/yr	624.31	821.01	985.11
Process Steam	MM \$/yr	1,105.50	1,453.90	1,744.50
SAGD Steam	MM \$/yr	2,719.50	3,947.10	4,334.90
Process Fuel	MM \$/yr	89.84	119.52	127.41
Diesel	MM \$/yr	504.56	663.54	796.16
Total cost	MM \$/yr	7,176.42	9,846.55	10,829.59
Unitary costs				
Mined SCO	\$/bbl	12.69	12.71	12.75
SAGD SCO	\$/bbl	13.32	13.30	13.34
Diluted Bitumen	\$/bbl	5.92	5.94	5.95

Table 4-9. Energy producer's infrastructure for Case Study 2020 (No CO_2 Target)

	Low		Reference		High	
Energy Producer	Units	Capacity	Units	Capacity	Units	Capacity
SB	20	254.05 tonne/h	29	230.41 tonne/h	35	229.06 tonne/h
SSEB	61	337 tonne/h	90	331.51 tonne/h	98	334.36 tonne/h
HP_2	3	25.466 tonne /h 186,640 kW	4	26.27 tonne /h 256,730 kW	4	26.635 tonne/h 260,270 kW
HP_4	4	25.922 tonne /h 125,670 kW	5	26.635 tonne /h 161,410 kW	5	26.635 tonne/h 161,410 kW
PP_1	-	-	1	174,090 kW	1	174,510 kW
PP_2	1	471,600 kW	1	471,600 kW	1	435,440 kW

Figure 4-7 shows the distribution between the production schemes selected by the integrated model for each scenario. As shown on this Figure, the most suitable synthetic crude oil production schemes are OPS_3 and OPS_6. Although the 2003 case study did not include integrated SAGD/Upgrading schemes (OPS_5- OPS_7), the predictions obtained for 2020 shows that OPS_3 remains as the main oil producer. Thus, the result obtained for the present case study is consistent with those obtained for the 2003 case study. As mentioned above, OPS_3 is the preferred scheme because is the most energy efficient production method per barrel of SCO produced. According to reports from the National Energy Board of Canada, SAGD bitumen extraction has been more expensive than mined bitumen extraction [48], [51]. Therefore, it is expected that Mining/Upgrading scheme (OPS_3) is less expensive than integrated SAGD/Upgrading scheme (OPS_6).

The integrated Mining/Upgrading scheme OPS_2 is the second largest production scheme selected by the optimization model. This is because OPS_2 is based on hydrocracking, which uses hydrogen to upgrade the bitumen. For this case study there are coal gasification (IGCC) hydrogen plants available that uses coal as feedstock and co-generate power. Coal is considered to be 9.2 times less expensive than natural gas for this case study. Thus, the hydrogen produced with IGCC for OPS_2 is less expensive than producing oil from OPS_1 because they require large amounts of natural gas as a process fuel. The results for the three scenarios show that the model only selected IGCC hydrogen plants to cover the hydrogen requirements. This is indeed a suitable technology in the present model since it uses coal as feedstock and co-generates power simultaneously with the hydrogen. Likewise, OPS_2 is more economically attractive than OPS_4 because it requires less hot water and process steam per barrel of SCO produced. These two energy commodities are produced in natural gas fired boilers.

OPS_6 is the most suitable integrated SAGD/Upgrading scheme because is based on hydrocracking, which is a suitable process since the hydrogen is produced in IGCC plants.

Moreover, OPS_6 was modeled with the highest SCO conversion among these schemes (95%). OPS_5 is the other selected scheme on this group (SAGD/Upgrading scheme). Although this last scheme depends on thermocracking which consumes large amounts of process fuel, OPS_7 also includes thermo-cracking as part of its upgrading process. Additionally, OPS_7 consumes 5.77 times more power than OPS_5 in upgrading.

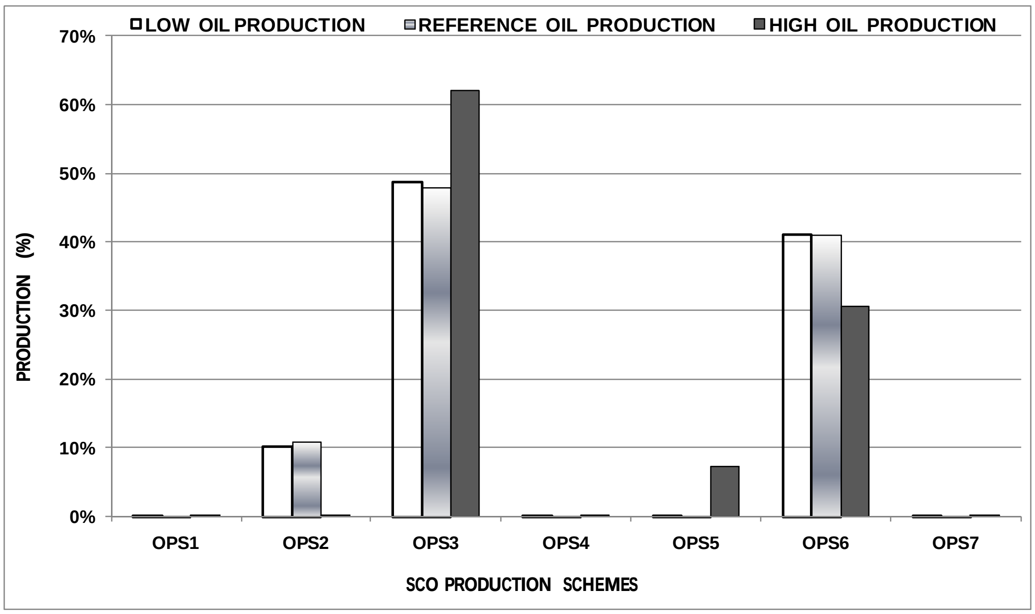

Figure 4-7. Comparison of SCO production schemes for different oil production scenarios for 2020

The results from Figure 4-7 show that the optimization model focuses on reducing the natural gas consumption which is the dominating cost in the present energy model's cost function. Thus, the production schemes that required considerable amounts of process fuel, hot water and process steam are less favored by the optimization model because they rely on natural gas as feedstock fuel.

The energy costs breakdowns for the scenarios considered for this case study are shown in Figure 4-8. As shown in this Figure, steam production for SAGD extraction is the dominant energy cost. This is because SAGD steam is used in SAGD SCO and diluted bitumen production. Moreover, SAGD steam production is highly energy intensive, i.e., it requires 2,469 MJ per tonne of SAGD steam produced. Additionally, 2.4 tonne of steam are required per tonne of bitumen recovered during SAGD extraction. Table 4-8 also shows the average unit costs per integrated scheme for SCO and bitumen production (Costs are in 2007 US $). The average production cost per barrel of mined SCO is lower than SAGD SCO because mining extraction is cheaper than SAGD extraction. This is because a significant amount of SAGD steam is used to extract the bitumen contained in the sand. Although SAGD extraction is more expensive, it is estimated that 80% or more of the bitumen reserves in the Oil Sands required thermal extraction methods for its recovery [2]. Therefore, in this study thermal extraction takes an important place given its promising future as leading extraction method in the future of Canadian Oil Sands operations. Furthermore, thermal bitumen extraction is projected to take over mining extraction combining SCO and diluted bitumen production by year 2020. Figure 4-8 also shows that the second highest energy cost is the hydrogen cost. According to the results, hydrogen will be required in 3 out of the 4 production schemes selected by the optimization model (OPS_2-OPS_3 and OPS_6). This is because the upgrading processes for these schemes are based only on hydro-cracking (OPS_2 and OPS_6) or a combination of hydro and thermo-cracking (OPS_3). Moreover, hydrocracking is part of the two schemes that produced almost 90% of the total SCO. On the other hand, the process fuel (natural gas) represents the lowest energy cost. This is because the integrated model selects hydrocracking based schemes over thermocracking based schemes. As mentioned above, schemes that include hydrocracking are most suitable to be selected because hydrogen can be produced in IGCC plats that are available in the model. The IGCC plants consume coal as feedstock whereas the thermocracking depends on process fuel (natural gas) for heating purposes to crack the bitumen in upgrading.

Following Figure 4-7 and Table 4-8, the SCO production schemes distribution and capacities remained unchanged for the low and reference production scenarios. Also, most of the power and hydrogen generated for the low and reference scenarios is based on coal technologies generation. Coal technologies are used because coal is 9.2 times cheaper than natural gas, natural gas is the fuel used by energy producers in a BAU scenario [11]. Thus, coal-based energy producers are more likely to be selected in the optimization model because they are economically attractive technologies at the expense of producing significant CO_2 emissions. However, the generation of electricity for the reference scenario is partially achieved using NGCC power plants (PP_1) whereas the low production scenario based the power generation only on Supercritical coal without CO_2 capture (PP_2). This is because the BAU scenario assumes only natural gas energy producers, a cleaner technology. To satisfy the hydrogen demand growth for the reference case more IGCC plants are required and more GHG emissions generated at a higher rate. Thus, the energy model needs to select a clean (and expensive) technology for power generation (NGCC) in the reference scenario to meet both the oil production and the GHG emissions (BAU) estimated for that year.

The production schemes' configuration changed for the high oil production scenario with respect to the low and reference scenarios. In the high production scenario, OPS_5 was selected as SCO producer whereas the operation capacity of scheme OPS_3 was increased at the expense of a reduction in the OPS_6's capacity (see Figure 4.7). Although the oil production increased from the reference to the high production scenario by a 10.5%, the hydrogen demand for the high scenario remains almost unchanged with respect to the reference scenario. Thus, the hydrogen producers' configuration is the same for both the reference and the high scenarios. Coal gasification plants are an economically attractive technology to produce hydrogen at the expense that it generates significant amount of CO_2 emissions. Therefore, the model chooses to reduce the production in scheme OPS_6 to control the hydrogen demands and maintain the GHG emissions at levels corresponding to a BAU scenario. This part of the SCO production is distributed between OPS_3, one of the most energy efficient SCO producers in the model, and OPS_5 which is based on thermocracking, i.e., it does not require hydrogen to crack the heavy oil. The changes in the oil producer's configurations for the high oil production scenario allow maintaining the energy production costs close to the average cost determined for the low and reference scenarios (see Table 4.8).

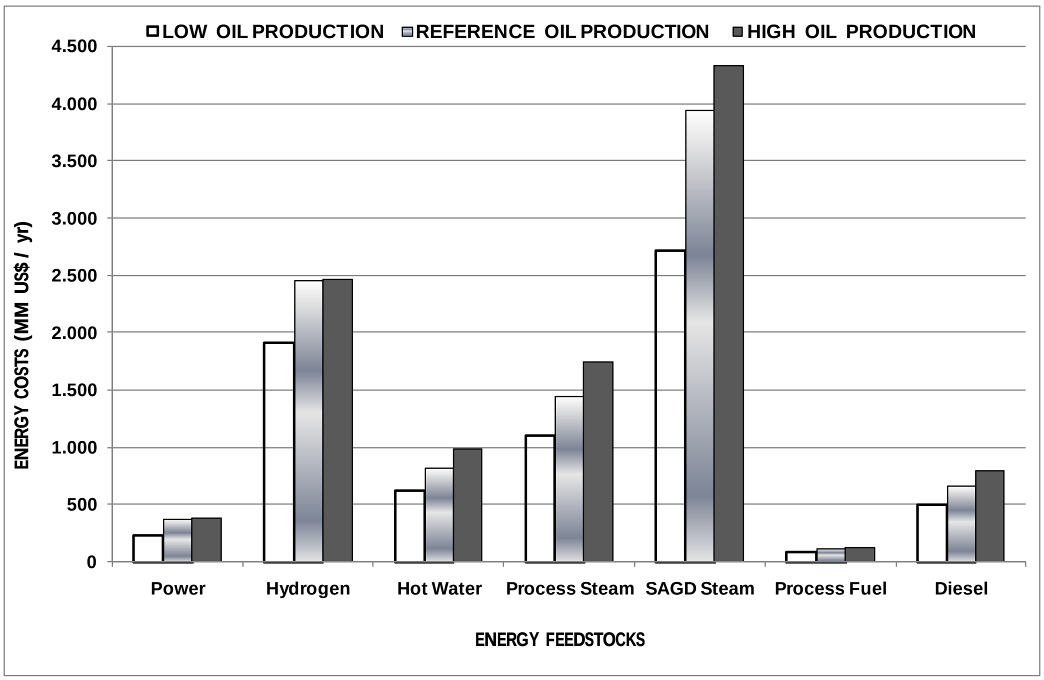

Figure 4-8. Energy costs for the oil production infrastructure of the year 2020

4.2.2 Simulation under governmental plan to reduce greenhouse gases (GHG) for 2020

The present case study was also used to determine the energy costs of the Oil Sands operations following a report published by the Canadian Federal Government: *Turning the Corner* [15]. This report is a notice of intent to develop and implement regulations for reducing greenhouse gas (GHG) and air pollution emissions from the industry. According to this plan, the Oil Sands GHG emissions for 2020 should be under 50 Megatonnes of CO_2 equivalent. Therefore, the model proposed in this work was used to simulate the Oil Sands operations subject to this environmental constraint (see equation 4 and the CO_2 constraint in problem 51). This scenario was solved for the 2020 reference oil production scenario (see Table 4-6). Tables 4-10 and 4-11 summarize the key results obtained with the CO_2 emission constraint for year 2020. As shown in Table 4-10, the most suitable synthetic crude oil production schemes are OPS_3 and OPS_5, respectively. Both schemes represent over 97.5% of the total SCO production expected for 2020 with this environmental restriction.

Table 4-10. Simulation results for Case Study 2020 with CO_2 Target

Variables	Units	Value
Production Schemes		
OPS_1	bbl/d	0
OPS_2	bbl/d	0
OPS_3	bbl/d	993,520
OPS_4	bbl/d	0
OPS_5	bbl/d	460,800
OPS_6	bbl/d	36,680
OPS_7	bbl/d	0
OPS (Total SCO production)	bbl/d	1,491,000
DB	bbl/d	1,291,000
CO_2 Emission	tonne/h	5,588
Energy demands		
Power	kWh	847,340
Steam	tonne/h	7,797
Hot Water	tonne/h	46,119
SAGD steam	tonne/h	30,333
Hydrogen	tonne/h	186.4
Process fuel (NG)	Nm^3/h	69,852
Diesel	l/h	70,713
Annual costs		
Power	MM $/yr	481.76
Hydrogen	MM $/yr	1,941.20
Hot Water	MM $/yr	958.07
Process Steam	MM $/yr	1,696.60
SAGD Steam	MM $/yr	4,012.90
Process Fuel	MM $/yr	158.79
Diesel	MM $/yr	774.31
CO_2 Transport	MM $/yr	194.19
CO_2 Storage	MM $/yr	174.27
Total cost	MM $/yr	10,392.09

Moreover, OPS_3 constitutes two thirds of the total SCO production, i.e., OPS_3 remains as the main oil producer. This is because OPS_3 is an integrated Mining/Upgrading scheme (energy efficient and cheaper scheme). In-situ production schemes, e.g., OPS_5-OPS_7, create higher GHG emissions, i.e., in-situ production (without upgrading) generate on average 2.5 times more CO_2 emissions than mining (without upgrading) per barrel of bitumen produced [52]. Therefore, the model selects integrated Mining/Upgrading scheme over integrated SAGD/Upgrading schemes. The schemes with mining present similar GHG emissions per barrel of SCO produced. However, OPS_3 is the most energy efficient as described in previous sections.

In the present scenario the model selected OPS_5 as the principal integrated SAGD/Upgrading scheme. This is because OPS_5 uses thermocracking instead of hydrocracking in the upgrading stage. The cheapest process to produce hydrogen in the model is through IGCC plants, which has the highest rate of CO_2 emission per tonne of hydrogen produced (17.26 tonne CO_2/tonne H_2). Therefore, the optimization model selects thermocracking over hydrocracking based schemes to meet the user specified CO_2 emission target. Also, around 2.5% of the SCO is produced by scheme OPS_6 because it assumes the highest SCO conversion among the integrated SAGD/Upgrading schemes. The results shown in Table 4-10 also suggest that the Oil Sands energy costs are expected to be 5.54% higher when compared to the reference production case without CO_2 target. This is because the model selects a new distribution of production schemes and energy producers that generate less CO_2 at a higher cost. Also, part of the increase in the energy costs for this scenario was also due to the costs associated with CO_2 storage and transport. The energy infrastructure for the present scenario is shown in Table 4-11. The results from the present scenario suggest that other technologies may need to be implemented in the Oil Sands operations to reduce the emissions of CO_2.

Table 4-11. Energy producer's infrastructure for Case Study 2020 with CO_2 Target

Energy Producer	Units	Capacity
SB	29	268.86 tonne/h
SSEB	91	333.33 tonne/h
HP_2	1	26.635 tonne /h 65,069 kW
HP_4	6	26.635 tonne /h 193,690 kW
PP_1	1	395,920 kW
PP_6	1	215,520 kW

Chapter 5

5 Conclusions

A comprehensive integrated model was developed in this research to determine the production costs and the most suitable oil production schemes and energy producers' infrastructure for the Canadian Oil Sands operations. The integrated optimization model aims to minimize the total energy cost of the Oil Sands operations by selecting the most suitable production schemes and the energy producers' infrastructure (power and hydrogen plants, and boilers) in the presence of a CO_2 emission target constraint. The energy model developed in this work was validated using the Oil Sands operation reported for 2003. The simulation results obtained with the sequential mode, i.e., production schemes and corresponding operating conditions fixed at constant values, showed that the energy demands and the energy infrastructure correspond to those reported in a previous study [7] whereas the production costs match with the 2003 historical data reported in the literature [48]. GAMS was used as modeling package because is an effective platform to model and solve large-scale steady-state optimization problems. Also, GAMS has used to develop similar energy models available in the literature [45].

To demonstrate the potential benefits of using an integrated modeling approach, the 2003 case study was solved assuming that the total SCO and bitumen production for 2003 were given as inputs to the model. The results showed that the integrated approach returned savings that are 5.6% higher for the scenario than those obtained by the sequential mode. Thus, a more economically attractive solution for the Oil Sands operation was obtained when using the integrated operation approach. This approach involves the simultaneously consideration of the oil production schemes (OPS_i) and energy commodity producers, e.g., boilers, power and hydrogen plants, as decision variables in the problem formulation. The energy model was also used to forecast the Oil Sands operation for 2020. The proposed 2020 case study was simulated for three different production scenarios where the corresponding SCO and bitumen production forecast values fluctuates between a low, high and reference value. The results show that at lower oil production levels all the hydrogen and electricity tend to be produced in coal gasification plants (IGCC) whereas at higher production scenarios NGCC power plants are selected together with IGCC plants. Additionally the percentage of SCO produced by intensive hydrogen consumers, production schemes based on hydrocracking technology, is less favored by the optimization model when the oil production increases over the reference scenario's capacity, i.e., the percentage of SCO produced by these schemes is reduced and distributed among less hydrogen demander schemes. Thus the generation of hydrogen and GHG emission in coal gasification plants does not reach levels that are too high for maintaining the emissions at a BAU scenario's level. The general results obtained with the integrated model suggest that hydrocracking based schemes are more attractive than thermocracking based production technologies. This is because hydrogen can be produced in IGCC plants which use coal as feedstock and also co-generate power. On the other hand, thermocracking mainly depends on process fuel (natural gas) which cost is much higher than coal. Moreover, OPS_3 (see Table 2-1) is the most suitable an energy efficient scheme included in the model because the energy requirements by unit of SCO produced are smaller than for the others schemes because it combines the use of thermocracking and hydrocracking as upgrading technologies. Moreover, OPS_3 includes hydrotransport as the only stage to treat the mined oil sand, which is more energy efficient than using conditioning.

When a CO_2 emission target was included as an environmental constraint for 2020, OPS_3 remained as the main SCO producer whereas OPS_5, lower GHG generator among the integrated SAGD/Upgrading schemes, became the second largest producer. Also, the total energy costs increased by 5.54% when compared to the 2020 reference production scenario without CO_2 emission target. This result indicates the level of compromise between reducing or not the CO_2 emissions in the Oil Sands operations with regard to a BAU emission scenario.

The results presented in this work show that the integrated model can be used as a practical tool to analyze the production costs of the Canadian Oil Sands. Also, this tool can be used for planning and scheduling the current and future energy producers' infrastructure.

5.1 Future work

The results and accomplishments obtained with the present research have led to the development of new ideas or directions that can be followed to improve the estimates on the Oil Sands operations. These ideas are aimed to add modeling details that can provide with a more accurate and realistic representation of the Canadian Oil Sands operations in the upcoming future.

- **In-depth analysis of the CO_2 emissions**

Due to time limitations, a comprehensive sensitivity analysis on the CO_2 emission levels was not performed at the time that this thesis was completed. This analysis will be useful to determine the influence of GHG emission reduction in the Oil Sands operations. This will allow Oil Sands operators to estimate their expected GHG emissions in the upcoming future and determine if they will comply with the emission target levels according to environmental regulations. Analyses on the type of energy and oil producers that maintains the oil operations within a CO_2 emission constraint can be useful to plan and schedule the future technologies that will be mostly used by this industry in the upcoming future. Moreover, the financial burden associated to decreasing CO_2 emission using carbon capture and storage system can be evaluated. The dependence of CO_2 abatement levels and the related capturing and sequestration cost can be also assessed. The results of this analysis will be presented in a future communication.

- **Introduction of nuclear energy in the operations**

Nuclear energy plants can be added to the model to account for the production of electricity, process and SAGD steam. This can be a feasible technology available in the medium term future since the Oil Sands industry are expected to increase significantly their production capacity. Therefore, the associated energy demands should intensively increase to support the operation of nuclear facilities. Moreover, recently the Energy Alberta Corporation filed an application with the Canadian Nuclear Safety Commission to site its first nuclear power plant near Peace River in Alberta. This energy facility is expected to have a direct impact on the power supply in the Athabasca region. Additionally nuclear facilities do not generate GHG emissions, which represent a major potential advantage over other energy producers given the uncertainty surrounding GHG emission reduction plans and environmental penalties for the future

- **Addition of poly-generation energy plants**

Poly-generation plants are energy producers that simultaneously generate two or more marketable energy commodities from the same energy source, i.e., poly-generation power plants and steam boilers. This would increase the energy production efficiency of the Oil Sands industry. Likewise, it will help to reduce GHG emissions since several commodities would be produced simultaneously from the same energy source, i.e., hydrogen, power, steam.

Although the present model includes coal gasification hydrogen plants with power co-generation, more poly-generation technologies should be included to increase the energy efficiency of the processes in the model. Especially steam boilers power co-generators which are currently being used in the Oil Sands industry.

- **Water management**

Reduction of freshwater consumption is one of the major environmental challenges that face the Oil Sands industry given the rapid expansion of Alberta's oil sector. There are environmental concerns that low winter flows may not be able to support the water requirements of a rapidly expanding Oil Sands industry. Thus, it has been anticipated that impacts to aquatic ecosystems will occur. Accordingly, the present integrated energy model can be expanded to consider water management within the Oil Sands operations. Water management can impact positively the oil industry operations by reducing the amount of freshwater required by using water recycling processes and technologies. This will also help to reduce the process tailing that are currently deposit in Tailing ponds, mining operation residues, which represent a large landscaping problem in the province of Alberta.

- **Yield introduction of key SCO hydrocarbon cuts**

The present integrated energy model can be expanded to include key SCO hydrocarbon cuts. The selection of the primary upgrading technology employed to crack the crude bitumen into a light and sweet product (SCO), i.e., hydrocracking or thermocracking, determines the composition that will yield the synthetic product. Thermocracking produces a highly aromatic SCO mainly characterized by low-quality distillates (jet and diesel fuel components) and gas oils whereas hydrocracking yields a lower aromatic SCO. The SCO is a product of higher economic value, relative to crude bitumen, that is commonly sold to refineries to produce usable petroleum products, e.g., gasoline, diesel, jet fuel, kerosene, butane and other hydrocarbons. Thus, the composition of the SCO will determine the type of usable products yield in the refinery. Also, it will determine the most suitable refinery to process the synthetic product. The determination of the SCO composition will allow scheduling the construction or expansion of upgrader facilities to supply the requirements of a given hydrocarbon cut needed in refineries to meet expected demands of usable petroleum products in the upcoming future.

- **Integration of refining activities into the model**

The model can be developed to integrate SCO refining activities for the production of added value oil products, e.g., lighter gasoline and distillates. This would enable the calculation of the optimal oil production and energy infrastructures required to meet an expected demand of intermediate and final consumption products, e.g., gasoline, jet fuel and butane, in the market. Accordingly, the required volumes of gasoline, jet fuel and butane could be use as input parameters into the model. This feature will increase the spectrum of scenarios that can be analyzed through the energy model.

- **Incorporating model parameter uncertainty within the analysis**

The present integrated energy model assumes that the model parameters are perfectly known a priori. A more realistic approach may consider the addition of uncertainty in the model parameters. For example, study the Oil Sands operations assuming that the natural gas price is represented by a normal probability distribution with a user-defined mean and standard deviation. A stochastic modeling tool will enable the user to project the probability distribution of the model outputs, i.e., energy commodity demands, energy plants, energy commodity costs, due to random variations in the model inputs, e.g., total SCO and crude bitumen productions, CO_2 emission targets, steam to oil ratio (SOR), number of energy producers available. A stochastic approach will help to generate more suitable projections and determine the most likely future scenarios in the Oil Sands operations. Thus operators will have more tools to plan and schedule their future activities and evaluate financial risks.

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