Computers and Chemical Engineering 90 (2016) 1–22

Contents lists available at ScienceDirect

Computers and Chemical Engineering

journal homepage: www.elsevier.com/locate/compchemeng

Optimized integration of renewable energy technologies into Alberta's oil sands industry

Mohamed Elsholkami[a], Ali Elkamel[a,*], Francisco Vargas[b]

[a] Department of Chemical Engineering, University of Waterloo, Waterloo, Canada
[b] Department of Chemical Engineering, Rice University, TX, United States

ARTICLE INFO

Article history:
Received 23 August 2015
Received in revised form 1 February 2016
Accepted 23 March 2016
Available online 29 March 2016

Keywords:
Process system engineering
Oil sands
Renewable energy
Mathematical modeling
Process optimization
Process modeling
Carbon management

ABSTRACT

An energy optimization model for the integration of renewable technologies into the energy infrastructure of the oil sands industry is presented. The proposed model determines the optimal configuration of oil producers and the energy infrastructure required to meet their energy demands. The model is geared toward the minimization of cost subject to carbon dioxide emission constraints. A mixed integer non-linear optimization model is developed that simultaneously optimizes capacity expansion and new investment decisions of conventional and renewable energy technologies. To illustrate its applicability, the proposed model was applied to a case study using data reported in the literature for various years of oil sands operations. A rolling horizon approach was implemented to determine the effect of investment decisions of previous operational years on the selection of new investment options. Results were compared with and without the incorporation of renewable energy technologies. The results obtained indicate that the proposed model is a practical tool that can be employed to evaluate and plan oil sands and energy producers for future scenarios. Moreover, the results show that renewable energy technologies have significant potential in reducing reliance on fossil-fuel based technologies and their associated CO_2 emissions. The emission constraints set for the operational year 2025 can only be achieved by the incorporation of renewables in the energy production mix.

1. Introduction

1.1. Alberta's oil sands industry—current and future challenges

The majority of oil reserves in Canada are located in the Western Canada Sedimentary Basin, of which the oil sands in Alberta comprise the majority of reserves. The majority of Canadian oil sands are located in Alberta in three major deposits, which are Peace River, Cold Lake and Athabasca. The largest and most heavily developed among them is the Athabasca oil sands deposit, which includes deposits that can be surface mined and extensive in situ reserves. The Canadian Oil Sands is the third largest crude oil proven reserves in the world, which amount to proven reserves of about 168 billion barrels constituting approximately 97% of Canada's total oil reserves (Woynillowicz, 2005; National Energy Board, 2006).

The oil sands are a mixture of bitumen, sand, clay and water. Bitumen is a heavy viscous crude that requires significant amounts of energy for production, upgrading and transportation. Extracted bitumen can be diluted by solvents (e.g., naphtha) to reduce its viscosity for further transportation to be sold as commercial crude bitumen or to be upgraded to higher quality synthetic crude oil (SCO). Bitumen upgrading operations can be integrated with mining or steam assisted gravity drainage (SAGD) extraction operations, and they typically consist of hydrocracking or thermocracking processes to break the heavy hydrocarbon molecules into lighter ones. Mining extraction is typically employed for bitumen deposits located at depths up to 75 m. The oil sands are mined by electric and hydraulic shovels, which are then transported by trucks to separation units in which hot water and solvents are used to extract the bitumen from the oil sands mixture. In-situ methods are used for deep bitumen deposits that are located more than 75 m below the earth's surface, and they have been employed to recover deposits at depths within the range of 350–600 m below the surface. In-situ methods rely on the use of steam, solvents or thermal energy to extract the bitumen from the oil sands in order to enhance its flow, which is then pumped to the surface. The two prominent production technologies are mining and in-situ, the latter being more economically and environmentally preferable and will account to approximately two-thirds of future oil sands production capacity. Mining extraction is currently the dominant method used for bitumen extraction (National Energy Board, 2006; Oil Sands Discovery Centre, 2014; Kubik, 2013).

* Corresponding author.
E-mail address: aelkamel@uwaterloo.ca (A. Elkamel).

http://dx.doi.org/10.1016/j.compchemeng.2016.03.028

Nomenclatures

Indices

b	Type of steam and hot water boilers
e	Type of existing energy production technology
h	Type of hydrogen production technology
i	Type of energy production technology
m	Type of integrated mining/upgrading SCO production route
o	Type of SCO production route
p	Type of power production technology
s	Type of integrated SAGD/upgrading SCO production route

Sets

B	Set of boilers
E	Set of existing energy production units (i.e., power, hydrogen, steam and hot water producers)
H	Set of hydrogen production plants
I	Set of all energy production technologies
M	Set of integrated mining/upgrading SCO production routes
O	Set of all SCO production routes
P	Set of power production plants
S	Set of integrated SAGD/upgrading SCO production routes

Parameters

AWP	Annual energy yield of VESTAS wind turbine (kWh)
CCB_b	Amortized capital cost of boiler type b ($/year)
CCGEO	Amortized capital cost of geothermal plants ($/year)
CCH_h	Amortized capital cost of hydrogen plant type h ($/year)
CCHE	Amortized capital cost of electrolyzer ($/year)
CCP_p	Amortized capital cost of power plant type p ($/year)
CO_2E	Maximum allowable level of CO_2 emissions (ton CO_2/h)
d_m	Distance between mining location and extraction plant (m)
DR	Fraction of diluent
dT_m	Distance between extraction plant and tailing ponds (m)
ECB	Electricity requirement for the production of commercial crude bitumen (kWh/ton)
ECC_i	Electricity requirement for compressing CO_2 for transport (kWh/ton/km)
ECR	Power requirement for centrifugation (kWh/m^3)
ED_o	Electricity requirement for delayed cokers (kWh/ton)
EER	Electrolyzer energy requirement (kWh/Nm3)
EL_o	Electricity requirement for LC-finers (kWh/ton)
EPVF	Annuity factor for existing technologies
ESMR	Electricity requirement of steam methane reforming plants (kW/ton H_2)
ΔHSS	Change in enthalpy of SAGD steam (MJ/ton)
ΔHPS	Change in enthalpy of process steam (MJ/ton)
ΔHHW	Change in enthalpy of hot water (MJ/ton)
HHG	Hydrogen requirement for hydrotreatment of HGO (ton H_2/ton LGO)
HH_h^{max}	Maximum production capacity of hydrogen plant h (ton/h)
HHV_b	High heating value of fuel used in boiler technology b i.e., natural gas, biomass etc. (MJ/ton)
HHV_h	High heating value of fuel used in hydrogen technology h i.e., coal, natural gas, etc. (MJ/ton)
HHV_p	High heating value of fuel used in power technology p i.e., coal, natural gas, etc. (MJ/ton)
HLG	Hydrogen requirement for hydrotreatment of LGO (ton H_2/ton LGO)
HN	Hydrogen requirement for the hydrotreatment of naphtha (ton H_2/ton naphtha)
HNG	Heating value of natural gas (GJ/Nm^3)
HP_h^{cogen}	Power co-produced or consumed by hydrogen plants (kW/ton H_2)
HRP_p	Heat rate of power plant p (MJ/kWh)
HRH_h	Heating rate of hydrogen production technology h (MJ/ton H_2)
HRU_o	Hydrogen requirement for hydrocracking in low and high conversion LC-finers (ton H_2/ton feed)
$HRGEO^{max}$	Maximum heat rate provided by a geothermal plant (MJ/h)
FR_o	Natural gas requirement for LC-finers and delayed cokers (GJ/ton VTB)
L	Length of CO_2 pipeline (km)
MDC	Diesel consumption for mining extraction (L diesel/bbl bitumen)
η_b	Efficiency of boiler type b
OMB_b	Operating and maintenance cost of boiler type b ($/year)
OMGEO	Operating and maintenance cost of geothermal plants ($/year)
OMH_h	Operating and maintenance cost of hydrogen plant h ($/year)
OMHE	Operating and maintenance cost of electrolyzer ($/year)
OMP_p	Operating and maintenance cost of power plant p ($/year)
PFB_b	Unit cost of fuel utilized by SAGD boiler b ($/GJ or $/ton)
PF_m	Pumping factor for hydrotransport (kWh/ton/m)
PFH_h	Unit cost of fuel utilized by hydrogen plant h ($/GJ or $/ton)
PFP_p	Unit cost of fuel utilized by power plant p ($/GJ or $/ton)
PFT_m	Pumping factor for transport of tailings (kWh/ton/m)
PD	Unit cost of diesel ($/L)
PNG	Unit cost of natural gas utilized by natural gas boilers ($/GJ)
PP_p^{max}	Maximum power production capacity of plant p (kWh)
PVF	Annuity factor for newly established technologies
$EPVF_e$	Annuity factor for existing technologies
S_b^{max}	Maximum production capacity of boiler type b (ton/h)
SSC	Unit sequestration cost ($/ton CO_2)
SC_m	Steam requirement for conditioning stage (ton steam/ton feed)
SF	Steam requirement for bitumen extraction (ton steam/ton froth)
SOR	Steam to oil ratio (ton of steam/ton of bitumen)
SRD	Steam requirement for the diluent recovery unit (ton steam/ton feed)
SRF	Steam requirement for the fluid coker (ton steam/ton feed)