Supplying synthetic crude oil from Canadian oil sands: a comparative study of the costs and CO_2 emissions of mining and in-situ recovery

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1 Introduction

There are growing concerns about whether a petroleum-based economy can be sustained in the coming decades (Greene et al., 2005). High crude oil prices, uncertainties about the consequences of climate change and the eventual depletion of conventional oil resources raise the issue of alternative fuels, such as non-conventional oil. In particular, bitumen can be extracted and upgraded into synthetic crude oil, a substitute to conventional oil (AEUB, 2006).

Climate change is a "serious and urgent issue" (Stern, 2007). Anthropogenic CO_2 emissions accumulate in the atmosphere, leading to enhanced greenhouse effects and climate change. There are large uncertainties associated with this issue, from the scale of the impacts of climate change to the costs of mitigation (Stern, 2007 p33), but there is a growing consensus that this is an issue that the oil industry cannot ignore (Browne, 2006). Climate change analysts have traditionally focused on the aggregate carbon content of global fossil energy resources to argue that the extended use of fossil fuels is not compatible with atmospheric stabilisation targets for CO_2. However, the distribution of resources across the different fossil fuels also matters, as even a 450ppm target for CO_2 concentrations would allow total CO_2 emissions over this century to be substantially larger than those which would be produced by burning the total estimated resource base of conventional oil and gas. According to Grubb (2001), "the longer-term problem of climate change arises from the fuller and longer-term use of coal, and of unconventional deposits such as heavy oils, tar sands and oil shales." As conventional oil becomes scarcer, the transport sector will remain dependent on petroleum resources, if no oil substitute is available. Fuels from non-conventional oil resources are therefore likely to become the 'backstop fuel'. However, these resources involve higher CO_2 emissions per unit of energy produced than conventional oil and gas, as they require more energy to be extracted and upgraded (Grubb, 2001). In terms of investments in energy technologies, oil companies are expected to push towards 'the frontier of petroleum exploitation' rather than towards the renewable frontier (Grubb, 2001).

The role of technological change and learning has been well studied for low-carbon and other energy technologies (see for instance Grübler et al., 1999 and McDonald and Schrattenholzer, 2001). As is the case for most emerging technologies, the cost reduction resulting from experience or cumulative production is an argument in favour of investing in new, less carbon intensive energy technologies. The role of learning-by-doing in driving down costs has not normally been taken into account for non-conventional oil in climate change modelling, and Odell (1999) recommends that this inherent contradiction should be eliminated in order to "build an internally consistent model for the evolution of the global energy market".

This paper describes a simple probabilistic model for projecting the cost of supplying bitumen from mining and in-situ recovery methods, and the cost of supplying synthetic crude oil upgraded from mined and in-situ bitumen. The impact of the social cost of CO_2 on the costs of producing these fuels is also assessed. The model uses uncertain parameters, and Monte-Carlo simulations are performed to obtain the probability distribution over time of the costs of synthetic crude oil, with and without the social cost of CO_2.

2 Theoretical framework and literature review

This analysis aims to inform decision-making by assessing the future costs of supplying synthetic crude oil and the associated uncertainties. In particular, the influence of learning and depletion on these costs is examined.

2.1 Decision theory, uncertainty and subjective probabilities

Decision theory is "designed to help a decision maker choose among a set of alternatives in light of their possible consequences"; each alternative is associated with one or more probability distributions (Web Dictionary of Cybernetics and Systems, 2007).

One approach to measure the uncertainty of events is to use subjective probabilities that are based on reasonable assessments by experts. Bayesian theory uses these probabilities to represent the degree of belief of a subject.

The aim here is to express our uncertainty about the future costs of supplying alternative fuels. Uncertainty about future energy prices and technological developments is at the core of the economics of climate change, as the pace of technological change will greatly influence the costs of mitigating greenhouse gas emissions. Numerical modelling is used as a tool to help decision-making: a model is introduced that draws on the user's degree of belief about a series of parameters as an input (for example, Hope, 2006). A probability distribution is assigned to these parameters and the basis of these probabilities is "up-to-date knowledge from science and economics" (Stern, 2007 p33). The uncertainty associated with the validity of the input data is looked at, together with the influence of each parameter on the output.

According to Tversky and Kahneman, the subjective assessment of probability is often based on three heuristics: representativeness, availability and anchoring (1974, p3), which in turn lead to predictable biases. In particular in the case of anchoring, a bias is introduced by subjects who choose a single value as a starting point to assess a probability distribution. Tversky, Kahneman and other authors (Alpert and Raiffa 1969, Staël von Holstein 1971, Winkler 1967, as cited in Tversky and Kahneman 1974) note that these distributions show "large and systematic departures from proper calibration". This is explained by the fact that "subjects state overly narrow confidence intervals which reflect more certainty than is justified by their knowledge about the assessed quantities" (Tversty and Kahneman, 1974 p17).

The tendency to underestimate the uncertainty associated with probability distributions should be avoided. Therefore the distributions assigned to the input parameters of the model will be assessed using as large number of sources and estimates as possible. This justifies the wide ranges that were chosen in this study.

2.2 Learning

Learning curves have been used in several areas to identify technologies that could become competitive with adequate investment (Grübler et al., 1999). To build a consistent model for energy supply, technological change should be taken into account for non-conventional oil as well as for renewable energy technologies.

Experience curves are a powerful tool for energy policy making, they are used to "assess the prospects for future improvements in the performance of a technology" (IEA, 2000). They give an indication of the investments that are needed to make a technology competitive (IEA, 2000). Cost reductions are ultimately limited by physical constraints, and a 'bottom line cost' (Tsuchiya and Kobayashi, 2003) should be introduced to generalise the relationship, as shown in (Anderson and Winne, 2003):

$$C_t = C_{\min} + (C_0 - C_{\min}) \cdot \left(\frac{X_t}{X_0} \right)^{-b} \qquad (1)$$

C_t is the unit cost[1] at time t

C_0 is the initial unit cost

X_t is the cumulative production at time t

X_0 is the initial cumulative production

t is the time

b is the experience curve parameter or learning coefficient (no unit), $b \geq 0$

C_{min} is the minimum unit cost

The experience curve parameter b characterises the curvature of the curve. The learning rate (LR) is a parameter that expresses the rate at which costs decrease each time cumulative production doubles, and is given by: $LR = 1 - 2^{-b}$.

2.3 Depletion

Depletion should also be taken into account when assessing the prospects for the costs of supplying fossil fuels. The simplest model assumes that the costs of extracting the resources are constant and independent of the remaining stock

[1] The costs presented here are marginal costs, i.e. the sum of marginal capital costs and marginal operating costs.

and of the extraction rate (Hotelling, 1931). Alternative models assume increasing marginal extraction costs as the resource is depleted or increasing marginal extraction costs with the extraction rate, or both (Sweeney, 1992 p13).

Krautkraemer and Toman argue the basic constant extraction cost model wrongly assumes fixed and homogeneous resources and no change in extraction technology[2] (2003 p6). Non-renewable energy resources are in fact heterogeneous, as their quality and difficulty of extraction vary within and among deposits. They suggest incorporating the remaining stock of resources in the extraction cost function as a way to account for resource heterogeneity (Krautkraemer and Toman, 2003 p7).

Oil extraction costs are dependent upon the quality of the resource, and Sweeney shows that low-cost, high-quality resources will be produced before high-cost, low-quality resources: under competition, it is economically rational to produce the low cost, high quality resources first. It follows that under a given state of knowledge, the oil industry shows increasing costs, as an increase in output means that more is produced from high cost, low quality resources (Adelman, 1993 p9).

The approach taken by modellers is to try to reflect how costs could evolve with the growing difficulty of obtaining the resources under a given state of knowledge. In the RICE-99 model, Nordhaus and Boyer (1999) introduced a carbon-energy supply curve with carbon fuels available at rising costs. Chakravorty and Roumasset have also shown that a rising and convex extraction cost function predominates in the oil industry (1990).

Both depletion and technological advances are driving the supply of exhaustible energy resources and both need to be taken into account to forecast future non-conventional oil extraction costs. The combination of both effects results in a U-shaped cost curve for non-conventional oil.

2.4 Non-conventional oil

Conventional and non-conventional oil are usually distinguished by their physical properties: viscosity and density. Viscosity is a measure of the fluid's resistance to flow. It varies greatly with temperature. The oil viscosity at reservoir temperature determines how easily oil flows to the well for extraction. Oil density is a measure of mass per unit volume it is expressed in degrees of API gravity (USGS, 2003).

Conventional oil (also called light oil) has an API gravity ≥ 22° and a viscosity < 100 centipoises (cP). Medium-heavy oil is an asphaltic, dense (low API gravity) and viscous oil with 18°API<Density<25°API and 10cP<Viscosity<100cP. It is mobile at reservoir conditions.

[2] In this section we assume no technological change in extraction technologies. The learning effect will be treated separately.

Extra-heavy oil is more viscous and dense than medium-heavy oil (density<20°API and 100cP<viscosity<10,000cP). It is still mobile at reservoir conditions. Bitumen is a bit more dense oil and more viscous than extra-heavy oil (density<12°API and 10,000cP<viscosity). It is not mobile at reservoir conditions (Cupcic, 2003).

Conventional oil can also be defined as oil produced by primary or secondary recovery methods (own pressure, physical lift, water flood, and water or natural gas pressure maintenance), while non-conventional oil is not recoverable in its natural state through a well by ordinary oil production methods (Grand Dictionnaire Terminologique, 2007). Bitumen does not flow at reservoir conditions and usually occurs in oil sands. When near the surface, oil sands are excavated and bitumen is extracted from the mined material. When the resource is at greater depth, bitumen is recovered in-situ. Steam and solvents are injected into the reservoir to make the bitumen mobile so that it flows to the surface (Alberta EUB, 2005). Crude bitumen extracted from oil sands is upgraded into synthetic crude oil through carbon removal and hydrogen addition. Synthetic crude oil has similar characteristics as conventional crude oil, and can be refined.

3 Methods: Equations and parameters of the model

3.1 Learning and depletion

Equation 2 summarises the first version of the supply cost model for bitumen, including learning and depletion effects as it was introduced in (Méjean and Hope, 2008):

$$C_{Bitumen,t} = C_{\min} + (C_{Bitumen,0} - C_{\min}) \cdot \left(\frac{X_{Bitumen,t}}{X_{Bitumen,0}} \right)^{-b} + C_{\max} \cdot \left(\frac{X_{Bitumen,t}}{X_T} \right)^{\gamma} \qquad (2)$$

Learning Depletion

$X_{Bitumen,t}$ is the cumulative production at time t

$C_{Bitumen,t}$ is the cost of bitumen at time t

$X_{Bitumen,0}$ is the initial cumulative production

$C_{BIitumen,0}$ is the initial cost

C_{min} is the minimum cost of producing the resources

b is the learning coefficient

R is the recovery factor

Q is the total oil in place

C_{max} is the maximum cost of the depletion

γ is the exponent of the depletion curve

X_T is the ultimately recoverable resources

And $X_T = \mathrm{Q} \cdot \mathrm{R}$

Learning and depletion are driven by production (X_t). Learning drives costs down, and depletion drives costs up, as the resources become depleted and become more difficult to extract. X_T is obtained by multiplying two parameters: the total oil in place (Q) and the recovery factor (R). The learning coefficient b defines the pace at which technological change is driving costs down, and the exponent of the depletion cost curve gamma defines the pace at which depletion is driving costs up. The cumulative production at time t (X_t) is exogenous. The exponential form of the depletion part of the cost function is flexible as its parameters can be changed to fit simple as well as more sophisticated models.

3.2 Production

The cumulative production at time t (X_t) is obtained by summing over time the production rate at time t (x_t). The production rate is assumed to follow an S-curve: it grows exponentially before reaching a plateau (see Soderbergh, 2006). The production rate is modelled as shown in equation 3:

$$x_t = \frac{a}{c + e^{-d \cdot t}} \tag{3}$$

x_t is the production rate (barrels/y)

$\frac{a}{c}$ is the maximum production rate

t_1 is the inflection point, which determines d

Parameters a and c are defined by the upper bound of production capacity when time tends towards infinity and the actual production at time 0.

$$\lim_{t \to \infty} x_t = \frac{a}{c} \quad ; \quad x_0 = x_{t=2005}$$

This model is not entirely satisfactory, as the production rate is determined exogenously. In practice, the production rate will depend on conventional and non-conventional oil prices, which will be influenced by the cost of producing oil and should be decreasing in the longer-term because of depletion.

3.3 The social cost of CO_2

The social cost of CO_2 is the increase in future damage, discounted to the present day, that occurs if current emissions of CO_2 are increased by one ton. The social cost of CO_2 is increasing with time at the rate α, to account for the increasing damage costs over time:

$$C_{CO_2,t} = C_{CO_2,0} \cdot e^{\alpha(t-t_0)} \tag{4}$$

$C_{CO2,t}$ is the social cost of emitting CO_2 at time t (USD/ton CO_2)

$C_{CO2,0}$ is the social cost of emitting CO_2 at time 0 (USD/ton CO_2)

α is the rate of increase of the social cost of CO_2 with time t

The specific costs of CO_2 from bitumen production are calculated from the process unit emissions e as follows:

$$C_{Bitumen,t}^{CO_2} = C_{CO_2,t} \cdot e_{Bitumen,t} \tag{5}$$

$C_{Bitumen,t}^{CO_2}$ is the CO_2 cost associated with the production of bitumen (USD/barrel)

$C_{CO2,t}$ is the social cost of emitting CO_2 at time t (USD/tCO_2)

$e_{Bitumen,t}$ is the CO_2 emissions to produce one barrel of bitumen (tCO_2/barrel)

Unit emissions are assumed to decline with cumulative emissions because of greater efficiency in the extraction process.

$$e_{Bitumen,t} = e_{\min} + (e_{Bitumen,0} - e_{\min}) \cdot \left(\frac{E_{Bitumen,t}}{E_{Bitumen,0}} \right)^{-b_e} \tag{6}$$

$e_{Bitumen,t}$ is the CO_2 emissions to produce bitumen at time t (tCO_2/barrel)

$e_{Bitumen,0}$ is the CO_2 emissions to produce bitumen at time 0 (tCO_2/barrel)

$E_{Bitumen,t}$ is the cumulative CO_2 emissions from bitumen production at time t (tCO_2)

$E_{Bitumen,0}$ is the cumulative CO_2 emissions from bitumen production at time 0 (tCO_2)

e_{min} is the minimum CO_2 emissions to produce bitumen (tCO_2/barrel)

b_e is the learning coefficient

The same equations apply to the CO_2 costs and emissions associated with upgrading bitumen into synthetic crude oil.

3.4 Upgrading bitumen into synthetic crude oil

Upgrading is the process to convert mined bitumen and bitumen produced in-situ into synthetic crude oil. Synthetic crude oil (SCO) has similar density and viscosity to conventional light-medium crude oil (AEUB, 2003). Bitumen is upgraded into synthetic crude oil by adding hydrogen, subtracting carbon, or both (AEUB, 2003). In our model, upgrading costs are decreasing with cumulative upgrading capacity.

$$C_{Upgrading,t} = C_{Upgrading,\min} + (C_{Upgrading,0} - C_{Upgrading,\min}) \cdot \left(\frac{X_{Upgrading,t}}{X_{Upgrading,0}} \right)^{-b_U} \tag{7}$$

$C_{Upgrading,t}$ is the cost of upgrading bitumen into SCO (USD/barrel SCO)

$C_{Upgrading,min}$ is the minimum cost of upgrading bitumen into SCO (USD/barrel SCO)

$X_{Upgrading,t}$ is the cumulative upgrading capacity (barrels SCO)

$X_{Upgrading,0}$ is the cumulative upgrading capacity at time 0 (barrels SCO)

b_U is the learning coefficient (no unit)

3.5 Supply costs of synthetic crude oil

The costs of supplying synthetic crude oil are calculated as follows:

$$C_{SCO,t} = \frac{C_{Bitumen,t}}{k} + C_{Upgrading,t} \tag{8}$$

k is the conversion efficiency from bitumen to synthetic crude oil (barrels SCO per barrel bitumen)

When taking into account CO_2 emissions and costs, the equation for total synthetic crude oil costs becomes:

$$C_{SCO,t} = \frac{C_{Bitumen,t} + C_{Bitumen,t}^{CO_2}}{k} + C_{Upgrading,t} + C_{Upgrading,t}^{CO_2} \tag{9}$$

The learning, depletion and production parameters described above are not known precisely. The effect of uncertainty associated with these input variables on the resulting supply costs should be explored: uncertainty is introduced in the model by assigning subjective probability distributions to the model parameters.

4 Data: Estimation of the parameters

A triangular distribution is assigned to each parameter. Each distribution is defined by a minimum, a maximum and a most likely value. The direction of the skew of the triangular distribution is set by the size of the most likely value relative to the minimum and the maximum (Palisade, 2008). A literature review is conducted in order to define the ranges of estimates associated with each parameter.

4.1 Production parameters

Maximum production rate (x_{max}), initial production rate (x_0) and inflection time (t_1)

The range of production rate estimates found in the literature are summarized on Figures 1 and 2 for mined and in-situ produced bitumen, respectively.

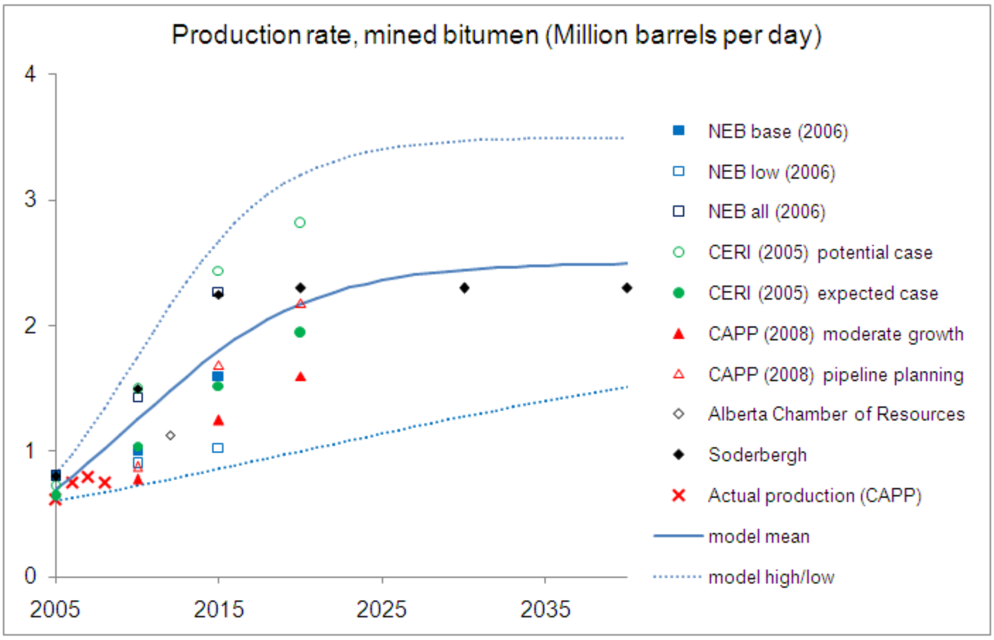

Figure 1 – Literature estimates for the production rate over time: mined bitumen

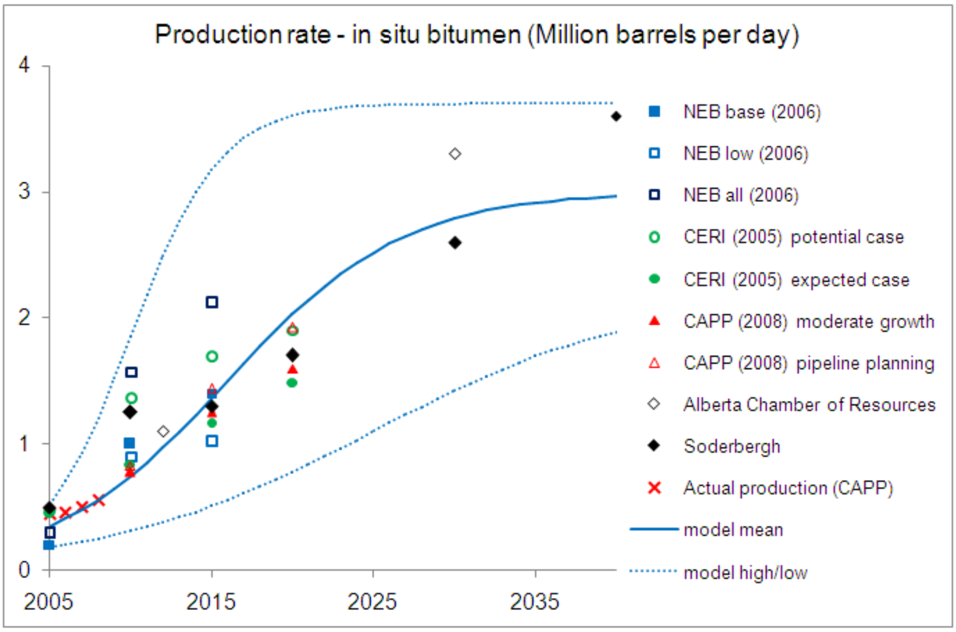

Figure 2 – Literature estimates for the production rate over time: in-situ bitumen

The ranges in table 1 are assigned to production parameters t_1 (inflection time), x_0 (initial production rate) and x_{max} (maximum production rate) to cover the literature estimates in figures 1 and 2. Triangular distributions are assigned to the production parameters and the most likely values shown in table 1 correspond to the model mean shown in figures 1 and 2.

	MINING			IN-SITU		
MINING	Minimum	Most likely	Maximum	Minimum	Most likely	Maximum

t_1, year	2009	2012	2015	2010	2013	2014
x_0, barrels per day	6.0E+05	7.5E+05	9.0E+05	2.0E+05	4.0E+05	6.0E+05
x_{max}, barrels per day	1.6E+06	2.4E+06	3.1E+06	1.6E+06	2.65E+06	3.7E+06

Table 1 – Production parameters estimates

Initial cumulative production (X_0)

The initial cumulative production of bitumen from mining and in-situ recovery techniques was obtained using historical data from (CAPP, 2009) (cf. Appendix). The initial cumulative production of mined bitumen is 3.2E+09 barrels (1967 – 2005) while the initial cumulative production of bitumen from in-situ recovery techniques is 1.6E+09 barrels (1967 – 2005). In this study, we will assume that all mined and in-situ produced bitumen is upgraded to SCO.

4.2 Resource parameters

Ultimate volume in place (Q)

A distinction must be made between the amount of bitumen physically occurring underground, and the amount of bitumen that will eventually be recovered from the deposits. We define the amount of bitumen physically occurring underground before any extraction has taken place as the ultimate volume in place. The ultimate volume of bitumen in place in Canada is estimated at about 2.5 trillion barrels (NEB, 2004 p4). Of the 2.5 trillion barrels of bitumen in place, about 0.14 trillion barrels would be “amenable to surface mining” (with an overburden thickness of 75 metres or less), while about 2.4 trillion barrels would be recoverable using in-situ production technologies (NEB, 2004 p4). The ranges of the ultimate volume in place are constructed around these estimates, with a 10% uncertainty range.

Recovery factor (R)

The recovery factor is the percentage of the total oil in place in a deposit that can be recovered by a combination of primary, secondary and tertiary techniques (Grand Dictionnaire Terminologique, 2007). In our study, the ultimate recovery factor is the amount of oil or bitumen that could ultimately be produced as a percentage of the total amount of bitumen in place.

According to the AEUB (2003 p2-8), the ultimate recoverable bitumen resources using surface mining techniques are estimated at about 1E+10m^3, i.e. 0.063E+12 barrels, or about 42% of the ultimate volume in place (mining). The estimated recovery factor for surface coal mining is 0.8 to 0.9, (USGS, 1989). The range for the mining recovery factor is thus chosen as 0.42 – 0.9.

According to the AEUB (2003 p2-8), the ultimate recoverable bitumen resources using in-situ techniques are about 3.9E+10 m^3, i.e. 0.25E+12 barrels, or about a tenth of the ultimate volume in place (in-situ). The estimates of the recovery factors available in the literature are closely linked to the performance of current technologies, and to current or anticipated economic conditions. Ideally this study should be conducted independently of these considerations, as it is very difficult to anticipate future technological breakthroughs and economic conditions. In Rogner's hydrocarbon resource assessment, "the broadest possible dimensions were applied without immediate reference to recoverability" (1997 p220). Rogner points out the "difficulty of incorporating future development efforts, technology change, and uncertainty into reserve assessments" and argues for the inclusion of all hydrocarbon occurrences, as the "a priori exclusion of presently subeconomic or geologically uncertain occurrences would certainly underestimate the hydrocarbon occurrence potentially available to humankind", (1997 p236). Rogner thus adopts the highest plausible value for the occurrences of non-conventional oil resources, as his objective is to assess "the ultimately available resource base beyond short-term techno-economic recovery limitations" (1997 p253).

The model introduces a depletion cost component that is solely based on the growing physical difficulty of producing bitumen. The recovery factor used to determine the costs associated with the depletion of the resources should therefore be set at the highest possible value. The previous estimates of the recovery factor are considered to be conservative, they will be chosen as the lower bound of the ranges.

4.3 Depletion parameters

Maximum costs (C_{max}) and depletion exponent (γ)

The estimates of the depletion parameters are obtained using the method described in (Méjean and Hope, 2008). Estimates from Attanasi (used in the SAUNER project), Rogner and Nordhaus and Boyer are used to determine the depletion parameters' ranges. The incremental cost function from which some of these estimates are derived expresses ''the quantity of resources that the industry is capable of adding to proved reserves or cumulative production'' as a function of long-term marginal costs (Attanasi, 1995, p2). These curves assume no subsequent cost reductions through technology learning (IEA, 2005a). The European SAUNER project uses Attanasi's estimates to produce world oil supply cost curves for various categories of oil, including tar sands. Rogner (1997) also produced similar aggregate quantity–cost curves for global oil resources. The resulting estimates for γ and C_{max} are summarised in table 2.

	SAUNER 2000	SAUNER 2000	Rogner 1997 p254	Nordhaus and Boyer 1999 p40
Category	Tar sands	Conventional oil	Global oil resources	Carbon fuels
γ (no unit)	1.07		1.04	4

*Cmax (*2005)USD/barrel	186*	120	240**	121***

*155 (1998)USD; **160 (1990)USD; ***81 (1990)USD

Table 2 – Literature estimates for depletion parameters

Rogner values all resource categories are as if ”all future productivity gains were realized immediately” (p253). In his analysis, “a productivity gain in the upstream sector of 1% per year is assumed (...) a resource that presently commands production costs of, for example, $40 per barrel of oil equivalent (boe) would, over a period of 50 years, drop gradually to $24”, (Rogner, 1997 p251). The high end of the conventional oil spectrum is 35 (1990) USD/barrel (including EOR). Taking out the 1% per year productivity gains, this is equivalent to 58 (1990) USD/barrel, or 86 (2005) USD/barrel (Rogner, 1997 p254). The high end of the non-conventional spectrum is 160 (1990) USD/barrel, which is equivalent to 267 (1990) USD/barrel without any productivity gain, or 395 (2005) USD/barrels (Rogner, 1997 p254).

The SAUNER project models production costs in 1998 USD per barrel. The highest conventional oil production costs are 50 (1998) USD/barrel (SAUNER, 2000b), or 60 (2005) USD/barrel. The depletion exponent is chosen between 1 and 4, but the probability distribution is skewed towards the lower bound of the range because a degree convexity corresponding to a value of 4 is considered to be very high in the case of the oil sands as these resources are well known.

4.4 Learning parameters

Initial costs (C_0)

Table 3 summarises the operating and supply costs of bitumen recovered using cold production, various in-situ techniques and surface mining. Upgrading costs are also included.

USD(2005) per barrel at the plant gate	Output	Operating costs	Supply costs	Source
In-situ (cold production)				
Wabasca, Seal	bitumen	5 - 7	12 - 15	NEB, 2006
Wabaka	bitumen	3.5 – 7.5	8.5 - 12	Cliffe, 2002
CHOPS - Cold Lake	bitumen	7 – 8	13 - 16	NEB, 2006
Cold Lake	bitumen	7 – 11	12 - 16	Cliffe, 2002
In-situ (thermal)	bitumen			
Cyclic Steam Stimulation (CSS)	bitumen	8 – 12	17 - 20	NEB, 2006
CSS	bitumen	7 – 12	12 - 19	Cliffe, 2002
CSS	bitumen	6 – 10	10 - 15	IEA, 2002
CSS	SCO	4.5 – 7.5		NRCan, 2003
Steam Assisted Gravity Drainage (SAGD)	bitumen	8 – 12	15 - 18	NEB, 2006
SAGD	bitumen	6 – 11	10 - 17	Cliffe, 2002
SAGD	bitumen	5 – 9	7 - 13	IEA, 2002
SAGD	SCO	3.5 – 7		NRCan, 2003
Mining				
Mining/Extraction	bitumen	7 – 10	15 - 17	NEB, 2006
Mining	bitumen	6 – 10	12 - 16	Cliffe, 2002
Mining	SCO	11 - 13.5		NRCan, 2003

Integrated Mining/Upgrading	SCO	15 - 18	30 - 33	NEB, 2006
Integrated Mining/Upgrading	SCO	12-15	18 - 22	Cliffe, 2002
Upgrading				
Stand-alone upgrader	SCO	12 - 15	22 - 27	Cliffe, 2002

Source: (Cliffe, 2002) and (IEA, 2002) are adapted from (Greene, 2003); (NEB, 2006)

Table 3 – Literature estimates for initial costs

It should be noted that the model does not include a parameter that reflects the losses occurring at the extraction stage. Bitumen is extracted from the mined oil sands before it is sent to the upgrader to be transformed into synthetic crude oil. These losses currently come close to about 10 to 13% of the initial amount of bitumen occurring in the mined oil sands (Alberta Chamber of Resources, 2004 p20). These losses have an impact on the bitumen production rate and the unit costs of producing bitumen. In fact, these losses are already included in the model, but in an implicit way. The estimates used to construct the ranges for the initial costs are found in the literature in dollars per barrel of bitumen, not in dollars per barrel of oil sand. These costs therefore already account for the losses occurring at the extraction stage. Similarly, the estimates obtained for future production rates are found in barrels of bitumen, and not in barrels of mined oil sands. Also, the estimation of the minimum mining costs (C_{min}) takes these losses into account (see paragraph below).

Minimum costs (C_{min})

The minimum costs of mining bitumen were estimated between 2 and 9 USD per barrel of bitumen in (Méjean and Hope, 2008). The minimum costs of producing bitumen through in-situ recovery techniques are estimated by examining the costs of producing Venezuelan heavy oil. Venezuelan heavy oil from the Orinoco belt flows at reservoir temperature and can be produced without additional “viscosity-reduction techniques” (IEA, 2005b p77). Greene (2003 p19) estimates the extraction costs of Venezuelan heavy oil at about 3 USD/barrel, and upgrading costs at over 4 USD/barrel. Also, the costs of primary recovery of heavy oil in difficult offshore areas can be as low as USD2/barrel (Roumasset et al., 1983). The range for the minimum cost of producing bitumen through in-situ recovery is thus chosen as 2 to 3 USD/barrel.

The upgrading stage integrates mature refinery processes in an original way. The minimum upgrading costs can be estimated using current petroleum refining costs. Several refining cost estimates were found in the literature, for instance refining cost estimates of 7.01 USD/barrel (including marketing and energy costs) (EIA, 2007 p33) and operating costs between 5 and 8 USD/barrel between 1988 and 2001 (EIA, 2003 p6).

Learning rate (LR)

Some learning rate estimates for petroleum refining and chemical refining found in the literature are summarized in table 4.

Type of process	Learning rate (no unit)	Source

Oil refining	0.1	Emerson, 1988 p138 in (Junius, 1997)
Chemical products	0.2 – 0.3	Lieberman, 1984 p221
Conventional oil technologies	0.04	Kahouli-Brahmi, 2008 p141

Table 4 – Literature estimates for the learning rate parameter

According to Kahouli-Brahmi (2008 p 141) "mature technologies such as coal, oil and lignite conventional technologies present relatively low learning rates of 4% on average".

The learning rate for Canadian bitumen production was estimated between 0.2 and 0.42 in (Méjean and Hope, 2008). The lower bound of the range was derived from (IEA, 2005b p166), while the upper bound of the range was calculated using historical data of supply costs and production volumes from the Canadian Petroleum Producers Association (CAPP) from 1983 to 1998. The learning rate of 0.42 is very high compared to other energy technologies (see McDonald and Schrattenholzer, 2001). We expand the previous study and differentiate between bitumen mining and in-situ production technologies.

The learning rate for in-situ bitumen is calculated from production data from CAPP (2009) and supply cost data from NRCan in (Alberta Chamber of Resources, 2004 p12). This regression gives a learning rate of 0.21 for in-situ production (R^2=0.94) between 1985 and 1991. Toman et al. (2008, p33) assume a more conservative learning rate of 0.10 for bitumen production from Canadian oil sands. As mining is now considered as a mature technology the value of 0.1 is chosen as the lower bound of the mining learning rate range. The following ranges are thus chosen for mining and in-situ learning rates. The learning rate of 0.25 for oil extraction (McDonald and Schrattenholzer, 2001 p257) falls into both bitumen production ranges.

4.5 CO_2 costs and emissions

Initial CO_2 costs C_{c0} and growth rate α

The following range for the social costs of CO_2 in 2008 is obtained from PAGE2002 with Stern review assumption: 25 – 300 (2000) USD/tCO_2 (Hope, 2008 p20). The social cost of CO_2 is assumed to grow at a rate of about 2 to 3% per year in real terms (Hope, 2008 p19). The social costs of CO_2 in year t_0 (2005) are thus estimated at about 23 to 283 (2000) USD/tCO_2, i.e. 26 - 322 (2005) USD/tCO_2 (with 1 USD(2000) = 1.138 USD(2005)).

Initial unit emissions (e_0)

The literature estimates for unit CO_2 emissions for mining recovery, in-situ recovery and upgrading are summarised in table 5.

Type of process	Initial unit emissions tCO_{2eq}/barrel	Source
Mining	0.04	Alberta Chamber of Resources, 2004 p62
Mining	0.035	LENEF and T.J.McCann & Associates in (Alberta Chamber of Resources, 2004 p62)
Mining	0.025 – 0.05	Cupcic, 2003 p24
In-situ	0.06	Alberta Chamber of Resources, 2004 p62
In-situ	0.081 (0.675tCO_{2eq}/m^3)*	CAPP, 2004 p30
In-situ	0.07 – 0.085	LENEF and T.J.McCann & Associates in (Alberta Chamber of Resources, 2004 p62)
In-situ (SAGD)	0.065 - 0.115	Cupcic, 2003 p24
Upgrading	0.075 – 0.09	LENEF and T.J.McCann & Associates in (Alberta Chamber of Resources, 2004 p62)
Upgrading	0.038	Cupcic, 2003 p24
Light/medium crude oil	0.022 (0.18tCO_{2eq}/m^3)*	CAPP, 2004 p30

*1 barrel = 0.12 m^3

Table 5 – Literature estimates for unit emissions

CO_2 emissions are expected to increase when natural gas is replaced by residues to produce steam for recovery and hydrogen for upgrading. Flint provides some estimates for CO_2 emissions per barrel of SCO, shown in table 6.

Emissions (tCO_{2eq}/barrel SCO)	In-situ (SAGD) + upgrading		Mining + upgrading	
Process	Natural gas	Residue	Natural gas	Residue
Total recovery only (tCO_{2eq}/barrel bitumen)	*0.049-0.054*	*0.077-0.086*	*0.027-0.030*	*0.037-0.041*
Total upgrading only	*0.045*	*0.085*	*0.045*	*0.085*

Table 6 – Comparison between natural gas and residue fuelled upgrading processes: unit emissions

Initial cumulative emissions (E)

An estimate for initial cumulative CO_2 emissions is obtained by multiplying the initial cumulative production of bitumen (in barrels) by the range for initial unit emissions (in tCO_{2eq} per barrel). This method gives the following estimates, which are chosen as the lower bound of the range, as unit CO_2 emissions are assumed to have decreased over time in the past.

If we assume that only mined bitumen was upgraded to synthetic crude oil, the cumulative volume of bitumen upgraded equals 3.7E+09 barrels between 1967 and 2005, and the cumulative production of synthetic crude oil equals 2.6E+09 over the same period. An estimate for initial cumulative CO_2 emissions is obtained by multiplying the initial cumulative production of synthetic crude oil (in barrels) by the range for initial unit emissions (in tCO_{2eq} per barrel of synthetic crude oil). This method gives the estimates in table 7, which again are chosen as the lower bound of the range, as unit CO_2 emissions are assumed to have decreased over time in the past.

Type of process	Initial cumulative production (barrels)	Initial unit emissions (tCO_{2eq}/barrel)	Initial cumulative emissions (tCO_{2e})

Mining	3.9E+09	0.025 – 0.05	0.98E+08 – 2.0E+08
In-situ	1.6E+09	0.06 – 0.115	0.96E+08 – 1.8E+08
Upgrading	2.6E+09 (barrels SCO)	0.038 - 0.09 (tCO_{2eq}/barrel SCO)	0.99E+08 – 2.3E+08

Table 7 – Literature estimates for initial cumulative emissions

Historical unit emissions from (Alberta Chamber of Resources, 2004 p15) are used to find a higher estimate of the initial cumulative emissions. Unit CO_2 emissions are multiplied with bitumen production rate each year, and aggregated over the whole period. It should be noted that the CO_2 emissions data from (Alberta Chamber of Resources, 2004 p15) do not differentiate between in-situ or mining recovery. The following estimates are found: 4.6E+08 tCO_{2eq} for initial cumulative emissions from mining and 1.8E+08 tCO_{2eq} for initial cumulative emissions from in-situ.

Upgrading uses similar processes as those used in conventional oil refining. The cumulative emissions from petroleum refining in Canada from 1990 to 2005 amounted about 3.1E+08 tCO_{2eq} (Environment Canada, 2008 p31).

Minimum CO_2 emissions (e_{min})

According to (Flint, 2004 p65), the use of natural gas for bitumen recovery and hydrogen generation is responsible for over half of CO_2 emissions associated to SCO from mined bitumen, and 75% of CO_2 emissions associated to SCO produced from bitumen recovered in-situ. Also, between 8 and 12% of CO_2 emissions associated to SCO can be attributed to the energy use of the upgrader.

We estimate the "bottom line", minimum achievable CO_2 emissions for mining and in-situ recovery by assuming that only low-carbon energy is used for recovery and hydrogen production. In the case of bitumen recovery, it follows that both recovery energy and purchased power (see Flint, 2004 p20) have zero CO_2 emissions. These estimates are used as the lower bound of the range.

As upgrading uses similar processes as those used in conventional oil refining, but applied to a heavier feedstock, we chose the current CO_2 intensity of 0.036 t tCO_{2eq}/barrel of oil input in a conventional petroleum refinery (Chevron, 2008), as the upper bound of range for upgrading minimum emissions. The upper bound of the minimum CO_2 emissions of the mining and in-situ recovery processes are chosen just below the current emissions (associated to the use of natural gas).

4.6 Summary

Table 8 summarises the ranges that are assigned to each parameter in the model.

Parameters	**Minimum**	**Most likely**	**Maximum**	**Standard deviation**	**Unit**
Resources					

Mining resources in place *(Q_M)*	1.3E+11	1.41E+11	1.5E+11	4.09E+09	barrels
Mining recovery rate *(R_M)*	0.42	0.66	0.9	0.10	no unit
In-situ resources in place *(Q_{IS})*	2.16E+12	2.4E+12	2.64E+12	9.80E+10	barrels
In-situ recovery rate *(R_{IS})*	0.11	0.36	0.6	0.10	no unit
Production					
Initial mining production rate *($x_{M,0}$)*	6.0E+05	7.5E+05	9.0E+5	6.12E+04	barrels per day
Mining inflection time *($t_{M,1}$)*	2009	2012	2015	1	year
Maximum mining production rate	1.6E+06	2.2E+06	3.5E+06	3.97E+05	barrels per day
Initial in-situ production rate *($x_{IS,0}$)*	2.0E+05	4.0E+05	6.0E+05	8.16E+04	barrels per day
In-situ inflection time *($t_{IS,1}$)*	2015	2028	2040	5	year
Maximum in-situ production rate	1.6E+06	2.7E+06	3.7E+06	4.29E+05	barrels per day
Upgrading efficiency *(k)*	0.81	0.86	0.9	0.02	no unit
Depletion					
Maximum depletion costs *(C_{max})*	121	258	395	56	USD/barrel
Depletion exponent *(γ)*	1	1.9	4	0.63	no unit
Learning					
Initial mining costs *($C_{M,0}$)*	12	15	17	1	USD/barrel
Initial in-situ costs *($C_{IS,0}$)*	7	14	21	2.9	USD/barrel
Initial upgrading costs *($C_{U,0}$)*	22	25	27	1.0	USD/barrel
Mining learning rate *(LR_M)*	0.10	0.26	0.42	0.07	no unit
In-situ learning rate *(LR_{IS})*	0.21	0.32	0.42	0.04	no unit
Upgrading learning rate *(LR_U)*	0.04	0.17	0.3	0.05	no unit
Minimum mining costs *($C_{M,min}$)*	2	5.5	9	1.4	USD/barrel
Minimum in-situ costs *($C_{IS,min}$)*	2	2.5	3	0.2	USD/barrel
Minimum upgrading costs *($C_{U,min}$)*	4	6	8	0.8	USD/barrel SCO
CO2					
Initial CO_2 costs *($C_{C,0}$)*	26	85	322	64	USD/tCO_{2eq}
CO_2 costs growth rate *(α)*	0.02	0.025	0.03	0.00	no unit
In-situ initial emissions *($e_{M,0}$)*	0.049	0.038	0.115	0.02	tCO_{2eq}/barrel
Mining initial emissions *($e_{IS,0}$)*	0.025	0.02	0.05	0.01	tCO_{2eq}/barrel
Upgrading initial emissions *($e_{U,0}$)*	0.038	0.064	0.09	0.01	tCO_{2eq}/barrel SCO
In-situ cumulative emissions *($E_{M,0}$)*	0.98E+08	2.8E+08	4.6E+08	7.39E+07	tCO_{2eq}
Mining cumulative emissions *($E_{IS,0}$)*	0.96E+08	1.4E+08	1.8E+08	1.72E+07	tCO_{2eq}
Upgrading cumulative emissions *($E_{U,0}$)*	1.0E+08	2.1E+08	3.1E+08	4.29E+07	tCO_{2eq}
In-situ minimum emissions *($e_{M,min}$)*	0.015	0.020	0.024	0.002	tCO_{2eq}/barrel
Mining minimum emissions *($e_{IS,min}$)*	0.005	0.027	0.048	0.009	tCO_{2eq}/barrel
Upgrading minimum emissions *($e_{U,min}$)*	0.005	0.021	0.036	0.006	tCO_{2eq}/barrel SCO

Table 8 – Parameters ranges

The wide ranges translate the large uncertainty on these parameters. These ranges are illustrative: the figures are better than guesses, as the above discussion shows, but they are not the result of a formal elicitation exercise. It is assumed that all these parameters are independent. These ranges are fed into the model to obtain some cost results.

5 Results

5.1 Bitumen costs: with and without CO_2

5.1.1 Cost trend over time

Using the model described earlier and the parameter ranges summarised above, the results shown in figure 3 are obtained for the supply costs of Canadian bitumen over time. These results are obtained from a Monte-Carlo simulation of 10,000 runs. Costs are shown in (2005)USD/barrel.

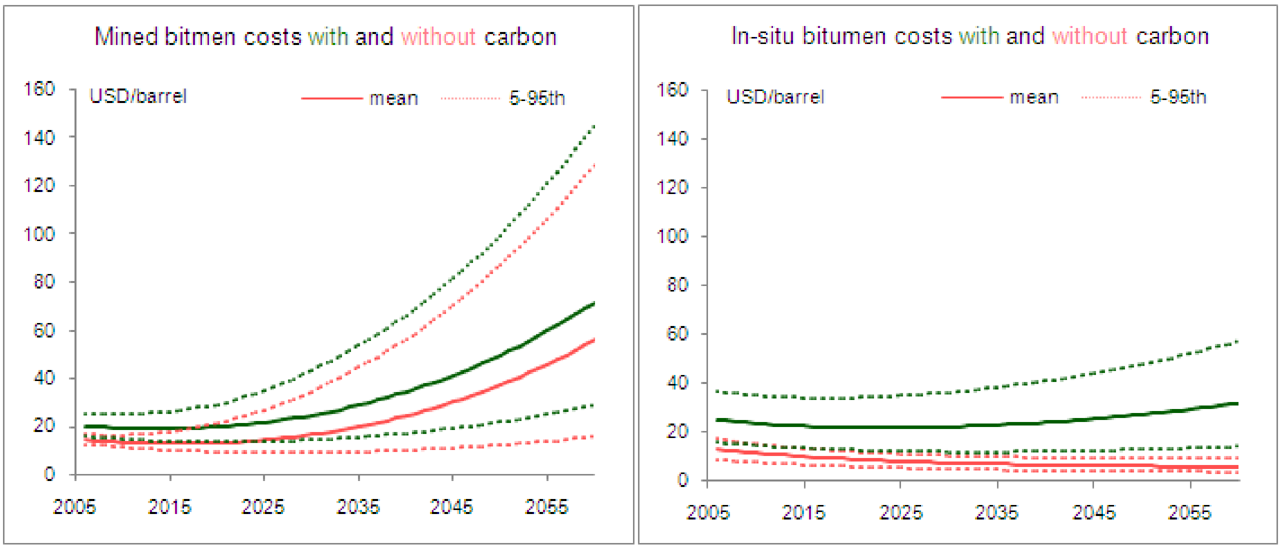

Figure 3 – Mined and in-situ bitumen costs over time, with and without CO_2 costs

The centre lines represent the trends in mean value. The outer bands are the 5th and 95th percentiles: the narrower the band, the less the uncertainty about the supply and total costs.

This model reveals the kind of uncertainties that need to be dealt with when designing policies. The results show large uncertainties on future costs of bitumen produced from mining and in-situ recovery techniques, with supply costs (without CO_2) falling in the range of 10 to 46 USD per barrel in 2030 (2005 USD) for mined bitumen, while in-situ produced bitumen supply costs fall in the range of 4 to 9 USD per barrel (2005 USD). Learning dominates in the case of in-situ bitumen produced supply costs (right, red), while mined bitumen supply costs are increasing after 2020 (left, red), driven by resource exhaustion.

The total costs (with CO_2 costs) show a similar pattern for mined bitumen, while total costs of in-situ produced bitumen are now increasing, driven by increasing CO_2 costs. This difference is explained by the fact that in-situ recovery techniques are much more carbon intensive than mining recovery techniques, hence the larger impact of CO_2 emissions when CO_2 costs are included.

5.1.2 Influences: Bitumen supply and total costs

The influences of each parameter on these results are examined more formally by using the regression sensitivity analysis in Palisade's @RISK. Mapped values show the change in costs in USD per barrel if one parameter increases by one standard deviation while all other parameters are constant (Palisade, 2008). Mapped values are the normalised regression coefficient associated with each input parameter, multiplied by the standard deviation of the output. The regressions mapped values are obtained from a simulation of 10,000 runs. These influences are shown for the years 2030 and 2050.

In-situ produced bitumen

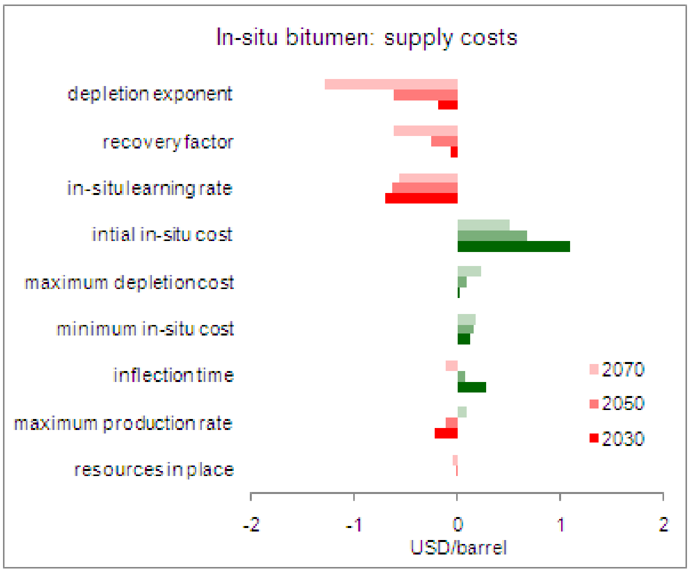

Figure 5 – Regression mapped values: In-situ bitumen supply costs

The longer bars represent the most significant variables. Figure 5 shows the main regression mapped values for the years 2030, 2050 and 2070 in order to highlight the change in trend between 2050 and 2070. These results are discussed below.

Learning and depletion parameters

The results show that the initial cost has the biggest influence on supply costs in 2030. The learning rate is the second most influential parameter in 2030. The sign of the sensitivity associated with the learning rate parameter is negative, as a higher learning rate will induce costs to decrease further. In 2080, the depletion exponent becomes the most influential parameter. As $\frac{X_t}{X_T} \leq 1$, a higher exponent (γ) means lower costs, hence the negative sign of the sensitivity. This shift in influence is revealed by a close examination of the influence of the production parameters x_{max} and t_1.

Production parameters

In 2030 and 2050, learning is the dominant effect and supply costs are decreasing, with learning being driven by production. The inflection time t_1 is the time when the growth of the production rate starts to decline, therefore a smaller t_1 means that production, and learning, happen sooner, hence the positive sign of the sensitivity. The same applies for the second production parameter x_{max} (maximum production rate). A higher maximum for the production rate means that more oil is produced, driving costs further down through learning.

Depletion, like learning, is driven by production. A smaller t_1 means that production and depletion happen sooner, driving up supply costs in 2070 once depletion effects start to bite. The same applies to the maximum production rate x_{max}. A higher value of the maximum production rate will increase supply costs in 2070.

The switch from learning to depletion being the dominant effect is shown by the change of sign of both influence between 2050 and 2070: negative to positive in the case of the maximum production rate x_{max}, and positive to negative in the case of the inflection time t_1.

Resource parameters

X_T is the ultimately recoverable resources and only appears in the depletion term of the model. If the recovery factor R increases, X_T increases, postponing depletion and its upward effect on costs, hence the negative signs of the correlation sensitivities. The recovery factor R is more influential in 2070 than in 2050 while the sign of its sensitivity remains the same. This is explained by the fact that this parameter only appears in the depletion part of the model and that the depletion effect dominates over the learning effect in 2070.

Mined bitumen

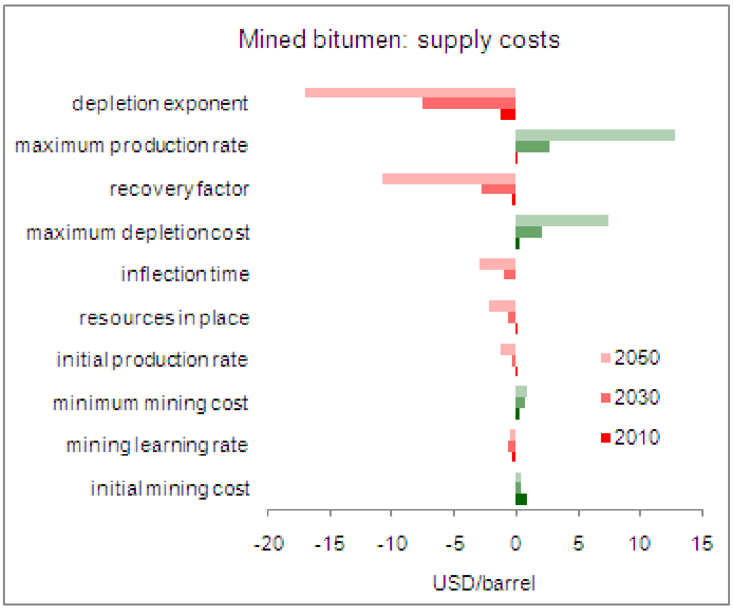

Figure 6 – Regression mapped values – Mined bitumen supply costs

The results show that the depletion exponent and the maximum production rate have the biggest influence on supply costs in 2050. This time, the regression mapped values are shown for the years 2030, 2050 and 2010 in order to highlight the change in trend between 2010 and 2030. In 2010, learning is the dominant effect: supply costs are decreasing (mean and 5th percentile of the supply costs, in red on the left hand side of Figure 1), with learning being driven by production. The positive sign of the inflection time influence and the negative sign of the x_{max} influence in 2010 show that learning is driving supply costs. However, this shift occurs earlier in the case of mined bitumen, as the ultimate volume of mineable bitumen is much smaller than the ultimate recoverable resources through in-situ techniques. With a similar production pattern to 2050, mining resources are depleted earlier than in-situ resources. Looking at these influences will help us to identify the most influential parameters and refine the study by finding better estimates for these parameters.

5.2 Results: Synthetic crude oil with and without CO_2 costs

5.2.1 Cost trend over time

The results below show the supply (without CO_2 costs) and total costs (with CO_2 costs associated with bitumen production and upgrading) of Canadian synthetic crude oil over time.

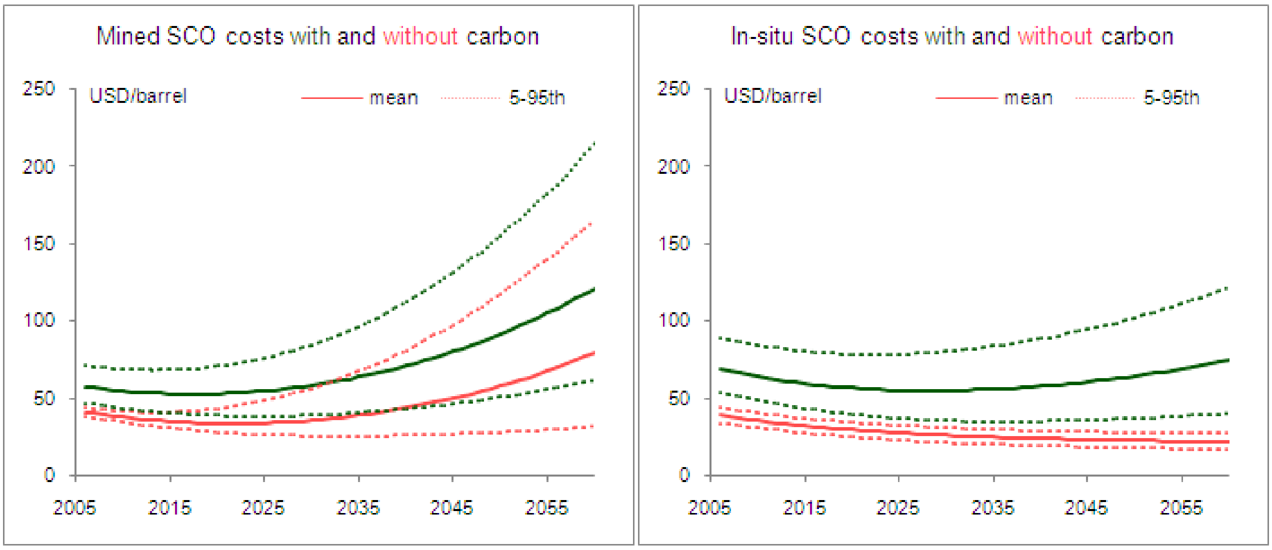

Figure 7 – Costs of synthetic crude oil from mined and in-situ bitumen, with and without CO_2 costs

The results show the uncertainties on future costs of synthetic crude oil produced from mined and in-situ bitumen. Supply costs (without CO_2) fall in the range of 28 to 63 USD per barrel in 2030 (2005 USD) for mined SCO, while in-situ produced SCO supply costs fall in the range of 21 to 30 USD per barrel (2005 USD). In-situ costs show less uncertainty than mined SCO costs, as the former are mainly driven by learning parameters: learning dominates in the case of in-situ SCO supply costs (right, red), while mined SCO supply costs are increasing after 2020 (mean value, left, red), driven by the exhaustion of resources.

Comparing supply costs (in red) to total costs (in green) show the impact of CO_2 costs on the final costs of synthetic crude oil. As in the case of bitumen, CO_2 costs have a very large impact on the costs of producing synthetic crude oil from in-situ produced bitumen, more than doubling these costs in 2030 from 25 USD per barrel SCO to 58 USD per barrel SCO.

5.2.2 Influences: Synthetic crude oil supply and total costs

The influences of each parameter on these results are examined more formally by using the regression sensitivity analysis in Palisade's @RISK. Mapped values show the change in costs if one parameter changes by one standard deviation while all other parameters are constant, (Palisade, 2008). The regressions are obtained from a simulation of 10,000 runs.

Synthetic crude oil upgraded from in-situ bitumen

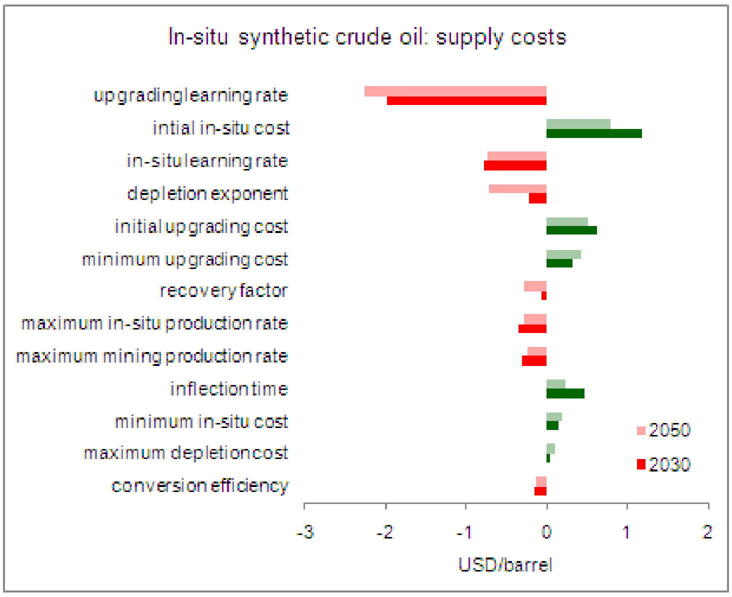

Figure 8 – Regressions mapped values: supply costs of synthetic crude oil from in-situ bitumen

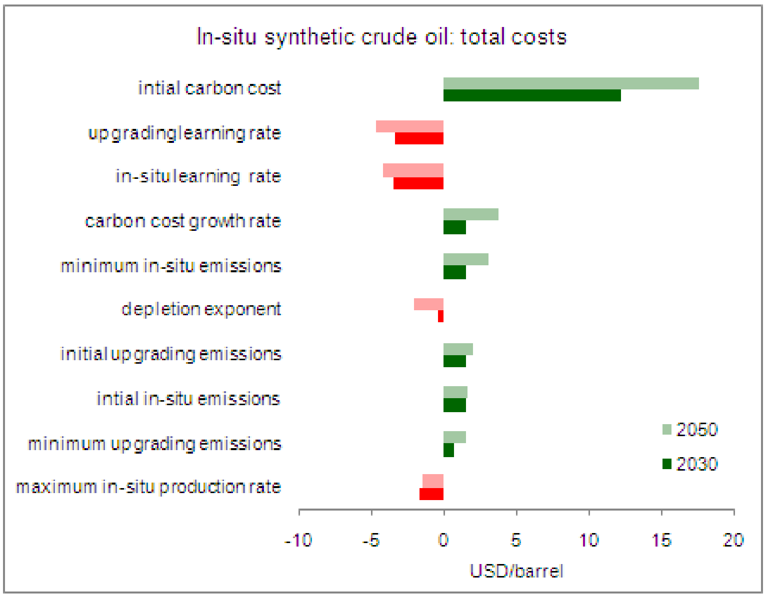

Figure 9 – Regressions mapped values: total costs of synthetic crude oil from in-situ bitumen

The regression mapped values for the supply costs of in-situ synthetic crude oil (excluding CO_2 costs) show the same pattern as in the case of in-situ bitumen, with the addition of upgrading parameters. The most influential parameter in 2050 is the learning rate associated with upgrading bitumen into synthetic crude oil. In 2050, the depletion exponent becomes more influential than the learning rate associated with bitumen production in-situ. In the case of total costs (including CO_2 costs), the initial CO_2 cost parameter is the most influential parameters in 2050.

Synthetic crude oil upgraded from mined bitumen

Figures 10 and 11 show the regression mapped values associated with the supply costs (excluding CO_2 costs) and total costs (including CO_2 costs) of synthetic crude oil from mined bitumen.

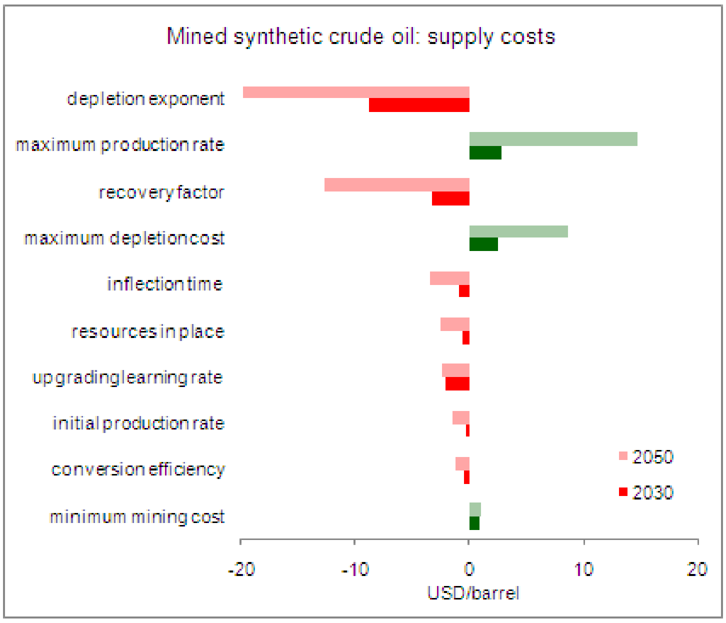

Figure 10 – Regressions mapped values: supply costs of synthetic crude oil from mined bitumen

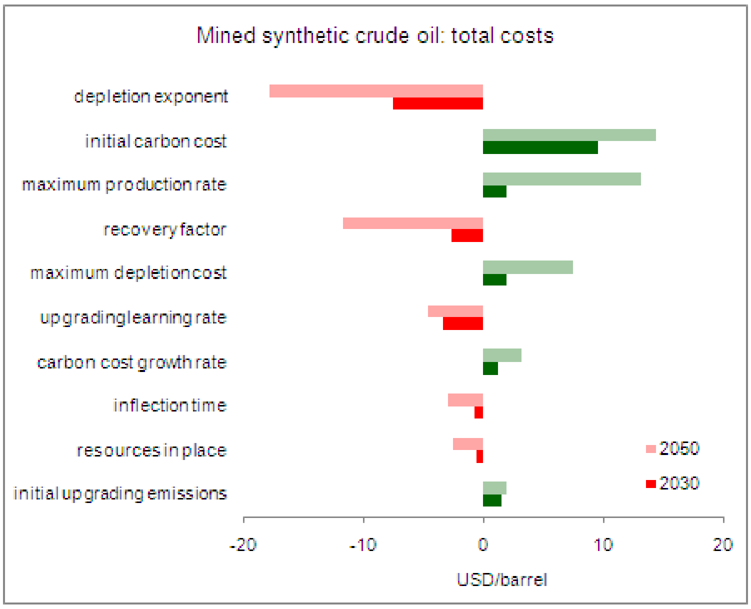

Figure 11 – Regressions mapped values: total costs of synthetic crude oil from mined bitumen

Again, the regression mapped values for the supply costs of synthetic crude oil show the same pattern as in the case of mined bitumen, with the addition of upgrading parameters. The most influential parameters in 2050 are still the depletion exponent and the maximum production rate.

In the case of total costs (including CO_2 costs), the depletion exponent parameter is still the most influential parameter in 2050. The second most influential parameter is the initial CO_2 cost. While in the case of synthetic crude oil from in-situ bitumen this parameter was of a higher order of magnitude than any other parameter, in the case of synthetic crude oil from mined bitumen the influence of the initial CO_2 costs is comparable to the influences of the maximum production rate, the depletion exponent and the mining recovery rate in 2050. So, while CO_2 costs have a significant effect on total costs of synthetic crude oil from mined bitumen, this effect is much smaller than in the case of synthetic crude oil from in-situ produced bitumen. Again, this is explained by the fact that in-situ recovery methods are much more carbon-intensive than mining recovery methods, and by the fact that the costs of mined bitumen are very much driven up by depletion.

6 Conclusion

In this paper, a model describing the effects of learning, depletion and CO_2 emissions on the costs of supplying bitumen and synthetic crude oil from oil sands deposits has been introduced. The learning, depletion, production, resources and CO_2 parameters of the model are not known precisely, and uncertainty was introduced by assigning a distribution to each parameter: these uncertainties propagate through the model, resulting in large uncertainties for the future supply costs of synthetic crude oil. The most influential parameters appear to be the learning parameters in the case of in-situ produced bitumen and the depletion parameters in the case of mined bitumen. CO_2 costs have a large impact of the total costs of synthetic crude oil, in particular in the case of synthetic crude oil from in-situ bitumen, due to the carbon-intensity of the recovery techniques: the addition of the social cost of CO_2 almost doubles the cost of producing synthetic crude oil from mined bitumen in 2050 (mean value), while the cost of producing synthetic crude oil from in-situ bitumen is multiplied by three. The results show that the social cost of CO_2 has a significant impact on the marginal cost of synthetic crude oil from Canadian oil sands. This effect could have a large impact on the price of oil when synthetic crude oil becomes the marginal source of crude oil supply. The potential impact of additional liquid fuel production, including synthetic crude oil and first generation biofuels, on the world oil market and world oil prices will be assessed in future research. The political, social and economic acceptability of a tax on fuels from non-conventional oil and biofuels will also be studied. Finally, the study will explore the consequences of the above on the development of international investments and markets for biofuels and non-conventional oil.

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Appendix – CO_2 emissions

Process	Unit (GHG)	2001	2002	2003	2004	2005	2006
Conventional oil and gas	ton/m3 oe	0.28	0.25	0.22	0.24	0.23	0.24
	ton/boe	0,034	0,030	0,026	0,029	0,028	0,029
In-situ	ton/m3 oe	0.68	0.51	0.49	0.48	0.45	0.45
	ton/boe	0,082	0,061	0,059	0,058	0,054	0,054
Mined and upgraded	ton/m3 oe		0.6	0.58	0.53	0.5	0.48
	ton/boe		0,072	0,070	0,064	0,060	0,058

Source: (CAPP, 2007 p41)

Table A.1 – Process emissions, 2001-2006 (CAPP, 2007)

Emissions (tCO2eq/barrel SCO)	In-situ (SAGD) + upgrading		Mining + upgrading	
Process	Natural gas	Residue	Natural gas	Residue
Recovery energy	0.05	0.085	0.012	0.024
Purchased power + miscellaneous	0.01	0.01	0.021	0.021
Upgrader net energy	0.01	0.015	0.01	0.015
Purchased power	0.005	0.005	0.005	0.005
H2 for 34 API SCO	0.025	0.04	0.025	0.04
Added H2 for 40 API SCO	-	0.02	-	0.02
Miscellaneous	0.005	0.005	0.005	0.005
Total	0.105	0.180	0.088	0.130
Total recovery only	0.06	0.095	0.033	0.045
Total recovery only (tCO_{2eq}/barrel bitumen)	*0.049-0.054*	*0.077-0.086*	*0.027-0.030*	*0.037-0.041*
Total upgrading only	*0.045*	*0.085*	*0.045*	*0.085*

Adapted from: (Flint, 2004 p20)

Table A.2 – Process emissions (Flint, 2004)