Canadian Energy Research Institute

Green Bitumen: The Role of Nuclear, Gasification and CCS in Alberta's Oil Sands

SUMMARY REPORT

David McColl
Senior Economist

Study No. 119 – Summary Report
ISBN 1-896091-87-3

February 2009

CANADIAN ENERGY RESEARCH INSTITUTE

Relevant • Independent • Objective

GREEN BITUMEN: THE ROLE OF NUCLEAR, GASIFICATION AND CCS IN ALBERTA'S OIL SANDS

SUMMARY REPORT

Green Bitumen: The Role of Nuclear, Gasification and
CCS in Alberta's Oil Sands – Summary Report

ISBN 1-896091-87-3

Authors of Multipart Report:
David McColl
Mellisa Mei
Paul Kralovic
Afshin Honarvar
Dinara Millington
Martin Slagorsky
Charu Kumar
Gurinder Gill

Acknowledgements: The author of this report would like to extend our thanks and gratitude to everyone involved in the production and editing of the material, including, but not limited to, Capri Gardener, Megan Murphy, Marwan Masri and Peter Howard.

CANADIAN ENERGY RESEARCH INSTITUTE
#150, 3512 – 33 STREET NW
CALGARY, ALBERTA
CANADA T2L A6

TELEPHONE: (403) 282-1231

February 2009
Printed on Recycled Paper Canada

The Canadian Energy Research Institute (CERI) is a cooperative research organization established by government and industry parties in 1975. Our mission is to produce relevant, independent, objective economic research and education in energy and environmental issues to benefit business, government, and the public.

The sponsors of the Institute are Natural Resources Canada; the Alberta Department of Energy; the Private Sector Sponsors of the Canadian Energy Research Institute (composed of more than one hundred corporate members from the energy production, transportation, marketing, distribution, and consuming sectors in Canada and abroad and the financial community); the University of Calgary; the Alberta Energy Resources Conservation Board; the British Columbia Ministry of Energy and Mines; Indian Affairs and Northern Development; the Alberta Utilities Consumer Advocate; and the Alberta Utilities Commission.

CERI's research program is guided by a Board of Directors named by the sponsoring organizations. Project advisory committees comprised of experts from government and industry are established to assist Institute staff and to review preliminary drafts of CERI reports. Responsibility for the content of studies rests with the author(s) and the officers of the Institute.

(THIS PAGE INTENTIONALLY LEFT BLANK)

TABLE OF CONTENTS

LIST OF FIGURES VII
LIST OF TABLES IX
CHAPTER 1 INTRODUCTION 1
CHAPTER 2 BACKGROUND 3
2.1 Oil Sands Backgrounder 3
2.2 Oil Sands Production – Historic 5
2.3 Oil Sands Extraction Technologies (beyond 2008) 7
2.4 Oil Sands Energy Requirements 7
2.5 Estimating Capital and Operating Costs for Oil Sands Projects 9
2.6 Greenfield Supply Cost Methods 10
2.6.1 Upgrading SAGD Bitumen Supply Cost Sensitivity 16
2.6.2 Upgrading Mined Bitumen Supply Cost Sensitivity 16
2.6.3 Integrated Mining and Extraction and Upgrading Supply Cost Reference Case.. 17
2.7 Production Profile (Projection to 2030) 18
2.7.1 Reference Case Projections (Production & Capital Investment) 18
2.7.2 Projection Reference Case 19
2.7.3 Projection Reference Case – Oil Sands Natural Gas Consumption 22
2.8 Oil Sands Emissions 24
CHAPTER 3 ALTERNATIVE FUELS AND CCS 29
3.1 Nuclear Energy 29
3.1.1 Advanced CANDU Reactor (ACRs) 29
3.1.2 Pressurized and Boiling Water Reactor (PWR and BWR) 29
3.1.3 Canadian Regulations on Nuclear Power Plants 31
3.1.4 Harnessing Nuclear Energy to Exploit the Oil Sands 31
3.1.5 "Small Scale" Nuclear Energy Facilities 35
3.2 Gasification and Synthesis Gas Production 38
3.2.1 CERI Gasification Design Assumptions 40
3.3 Alberta Emissions Plans 44
3.4 Carbon Capture and Storage (CCS) 45
3.5 Reference Case Emission Compliance Cost Projection 47
3.6 Deployment of CCS 50
CHAPTER 4 MOVING TOWARDS LOW EMISSIONS "GREEN BITUMEN" 55

(THIS PAGE INTENTIONALLY LEFT BLANK)

LIST OF FIGURES

2.1	Top Five World Proven Reserves	4
2.2	Historical Gross Crude Bitumen Production by Production Method	6
2.3	Historical Synthetic Crude Oil Production	6
2.4	Projection Reference Case, Gross Crude Bitumen Production	20
2.5	Projection Reference Case, SCO Bitumen Production	21
2.6	Projection Reference Case, Estimated Capital Spending for Greenfield Projects	22
2.7	Total Natural Gas Purchases – CERI Reference Case	24
2.8	Reference Case Direct Emissions Projection	26
2.9	Direct and Indirect Emissions	27
3.1	Diagram of a PWR Plant	30
3.2	Enhanced CANDU 6	32
3.3	ACR-1000	33
3.4	EPR 1600	33
3.5	Integrated Gasification Power Plant Configuration	40
3.6	Reference Case Emissions Compliance Cost Projection	47
3.7	Supply Costs of Alternative Technologies & Average Price of Natural Gas (Reference Case Projection)	49
3.8	Supply Costs of Alternative Technologies & Average Price of Natural Gas (Capture Cost Projection)	52
4.1	Reference Case Emissions Compliance Cost Projection	55
4.2	Summary of Supply Costs $/bbl of Bitumen and SCO (where applicable)	56
4.3	Total Emissions (MT of CO2e/year)	62
4.4	Total Emissions (MT of CO2e/year)	63

(THIS PAGE INTENTIONALLY LEFT BLANK)

LIST OF TABLES

2.1	In-Place Volumes and Established Reserves of Crude Bitumen	5
2.2	Oil Sands Natural Gas Requirements and Purchases	8
2.3	Oil Sands Electricity Requirements and Purchases	9
2.4	Financial Assumptions	11
2.5	In Situ Design and Cost Assumptions	12
2.6	Mining and Extraction, Stand Alone Upgraders, and Integrated Cost Assumptions	13
2.7	Bitumen Supply Cost at Plant Gate 30,000 barrel per day Cold Lake CSS Project	14
2.8	Bitumen Supply Cost at Plant Gate 30,000 barrel per day Athabasca SAGD Project	14
2.9	Bitumen Supply Cost at Plant Gate 100,000 barrel per day Athabasca Mining and Extraction Project	15
2.10	SCO Supply Cost at Plant Gate 100,000 barrel per day Stand Alone Upgrader Project	15
2.11	SCO Supply Cost at Plant Gate, 100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from SAGD	16
2.12	SCO Supply Cost at Plant Gate, 100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from Mine	17
2.13	SCO Supply Cost at Plant Gate 100,000 barrel per day Athabasca Mining and Extraction Project	17
2.14	Oil Sands Natural Gas Requirements and Purchases	23
2.15	Natural Gas – Global Warming Potential	25
3.1	Assumptions – Average Base-load Nuclear (Electricity)	34
3.2	Discounted Nuclear Supply Cost at Facility (5% discount)	35
3.3	Assumptions	36
3.4	Discounted Nuclear Supply Cost at Facility	37
3.5	Assumptions – Average Base-load Nuclear (Thermal)	38
3.6	Discounted Average Base-load Nuclear (Thermal) Supply Cost at Facility	38
3.7	Gasification Production Assumptions	41
3.8	Gasification Financial Assumptions	41
3.9	Discounted Gasification of Coal Supply Cost at Facility	42
3.10	Discounted Gasification of Petroleum Coke Supply Cost at Facility	42
3.11	Syngas and SNG Composition	43
3.12	Discounted Gasification of Coal Electricity Supply Cost at Facility	44
3.13	Discounted Gasification of Coke Electricity Supply Cost at Facility	44
3.14	Reference Case Alternative Fuel (Thermal) Supply Costs	48
3.15	Reference Case Alternative Fuel (Electric) Supply Costs	48
3.16	Capture Cost Projection Alternative Fuel (Thermal) Supply Costs	51
3.17	Capture Cost Projection Alternative Fuel (Electric) Supply Costs	51
4.1	Average Annual Point Source GHGs Over the Life of a Project with Alternative Fuels (Kg/bbl of output)	58
4.2	New Technology Implementation and Impact on Natural Gas Purchases	60

(THIS PAGE INTENTIONALLY LEFT BLANK)

CHAPTER 1
INTRODUCTION

The development of Alberta's oil sands is a critical component in both Alberta's and Canada's economy. While oil sands development is expected to grow over the coming decades, the amount of greenhouse gases (GHGs) emitted during the extraction and upgrading of bitumen is a drawback that will hinder future oil sands development.

This multipart study is motivated by the expected changes to Canada's regulatory regime as it relates to the costs associated with emitting GHGs, specifically carbon dioxide equivalent emissions. These changes are expected to have significant impacts on current and future oil sands projects, in addition to upgraders that transform raw bitumen into synthetic crude oil (SCO). The impacts will initially be felt by operators and proponents as their supply costs are forced upward by the need for carbon mitigating equipment or alternative technologies that produce less carbon – such as nuclear or carbon capture and storage (CCS), with or without gasification of a hydrocarbon. Various scenarios are explored in this study as it relates to carbon costs, alternative technologies, and the timeline for the deployment of alternative technologies. The study focuses on nuclear energy, gasification, and to a degree CCS as the most likely methods to reduce or eliminate anthropogenic emissions.

This summary consists of four chapters. Chapter 2 provides background information for this study and the current development of the oil sands. Chapter 3 describes the various alternative technologies, their supply costs, and how they could impact oil sands development costs. Chapter 4 provides a scenario for reducing GHGs based upon the technologies discussed in Chapter 3.

(THIS PAGE INTENTIONALLY LEFT BLANK)

CHAPTER 2
BACKGROUND

Before determining the amount of emissions from oil sands activities or how a selection of alternative technologies could impact oil sands supply costs, the study must first provide a projection for oil sands production in addition to supply costs. This process will produce a Reference Case for production and supply costs that will be used in estimating the impact from alternative technologies.

2.1 Oil Sands Backgrounder

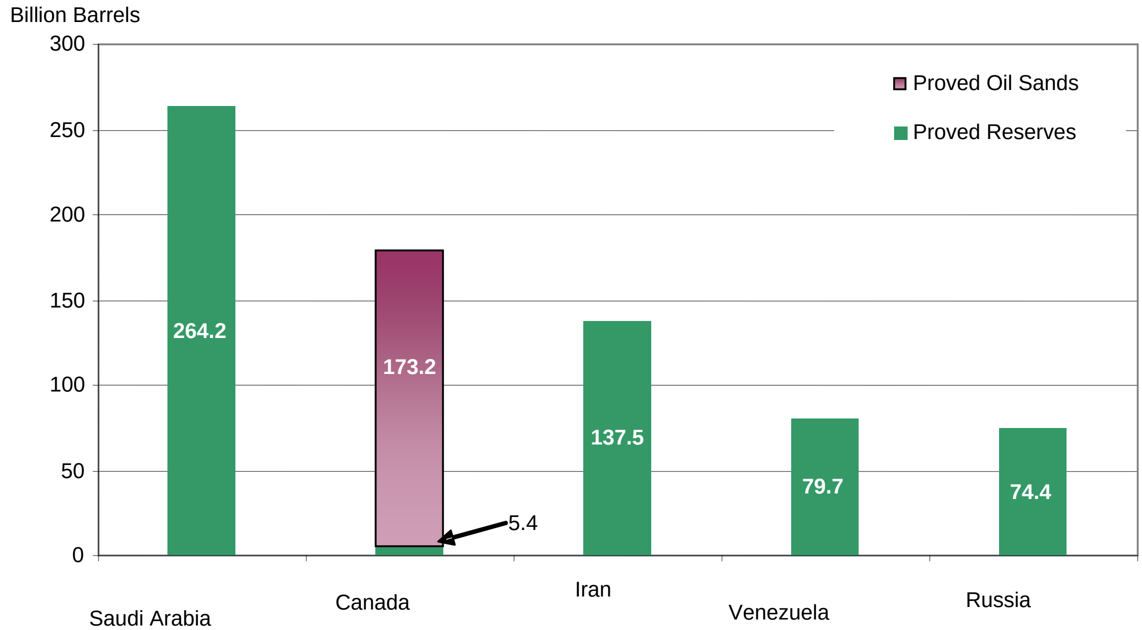
With an estimated initial volume in-place of approximately 1.7 trillion barrels (269 billion m^3) of crude bitumen, Alberta's oil sands are one of the largest hydrocarbon deposits in the world.[1] While not quite matching Saudi Arabia's conventional oil reserves, remaining established reserves of Canada's crude bitumen, at 173.2 billion barrels (27.53 billion m^3),[2] places Canada in the top tier of the world's oil reserves (see Figure 2.1).[3]

[1]Alberta Energy and Utilities Board, Alberta's Reserves 2005 and Supply/Demand Outlook 2006 – 2015, June 2006, http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf.

[2]Alberta Energy and Utilities Board, Alberta's Reserves 2006 and Supply/Demand Outlook 2007 – 2016, June 2007.

[3]The BP Group, *BP Statistical Review of World Energy 2003*, www.bp.com. Saudi Arabia's proved oil reserves at the end of 2002 stood at 261.8 billion barrels. Proved reserves are generally taken to be those quantities that geological and engineering information indicates can be recovered in the future from known reservoirs under existing economic and operating conditions with reasonable certainty.

Figure 2.1
Top Five World Proven Reserves



SOURCES: (1) Statistical Series 2003-98, Alberta's Reserves 2005 and Supply/Demand Outlook 2006-2015, Alberta Energy and Utilities Board (EUB); and (2) BP Statistical Review of World Energy 2006.

Remaining established reserves are calculated separately for those that are likely to be recovered by mining methods and those by in situ methods using established technology and under anticipated economic conditions.

Table 2.1 summarizes the Alberta Energy and Utilities Board's (EUB's) estimates of in-place volumes and established mineable and in situ crude bitumen reserves.[4] Of the remaining established reserves of 173.2 billion barrels (27.53 billion m^3), 21.0 billion barrels (3.34 billion m^3), or 12.13 percent, were under active development at year-end 2006. More than 80 percent of remaining established reserves are estimated to be recoverable from in situ techniques.[5]

In situ means "in place", and indicates that the bitumen is extracted from the sand in the reservoir. The two main in situ processes currently being used are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). These methods inject steam into the formation to heat the bitumen, allowing it to flow and be pumped to the surface.

---

[4] Alberta, Canada, Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Reserves 2006 and Supply Demand Outlook 2007-2016* (Calgary, Alberta, 2007), http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf.

[5] Ibid.

Table 2.1
In-Place Volumes and Established Reserves of Crude Bitumen
($10^9 m^3$ as of December 31, 2006)

Recovery Method	Initial Volume In-Place	Initial Established Reserves	Cumulative Production	Remaining Established Reserves	Remaining Established Reserves Under Active Development
Mineable	16.1	5.59	0.58	5.01	2.95
In situ	254.2	22.80	0.28	22.53	0.39
Total	270.3	28.39	0.86	27.53	3.34
	(1,701)[a]	(178.7)[a]	(5.4)[a]	(173.2)[a]	(21.0)[a]

[a]Imperial equivalent in billions of stock-tank barrels.

SOURCE: *Statistical Series 2007-98, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016*, Alberta Energy and Utilities Board.

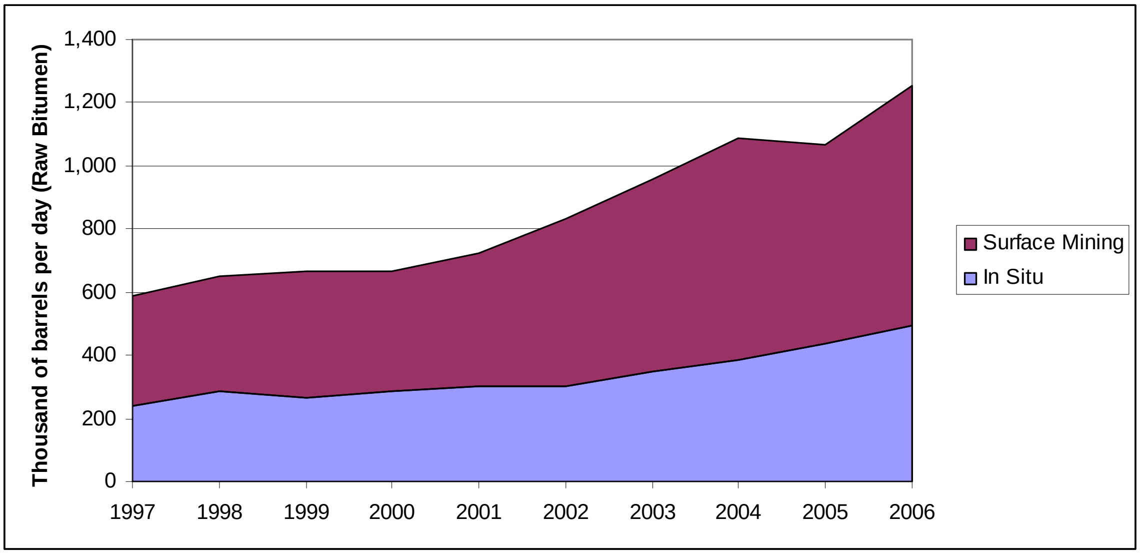
2.2 Oil Sands Production – Historic

Since the first production of oil sands from the Great Canadian Oil Sands (GCOS) project, oil sands production has witnessed numerous historical milestones. Total production has grown steadily since GCOS began operations in 1967, with rapid growth occurring over the 1990-2006 period. Total crude bitumen production, from mining and in situ, increased from 360,000 BPD (57.2 thousand m^3/d) in 1990 to 1.25 million BPD (38.1 million m^3/d)[6] in 2006. The main contributor to total crude bitumen production has historically been, and still is, from surface mining (see Figure 2.2).[7]

[6]Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Energy Reserves 2006 and Supply Demand Outlook 2073-2016* (Calgary, Alberta, 2007).

[7]In this section, "enhanced" in situ refers to in situ production using "tertiary" recovery technique; "primary" in situ refers to in situ production using natural flow or artificial lift. Primary in situ may also be referred to as cold heavy oil production with sand (CHOPS).

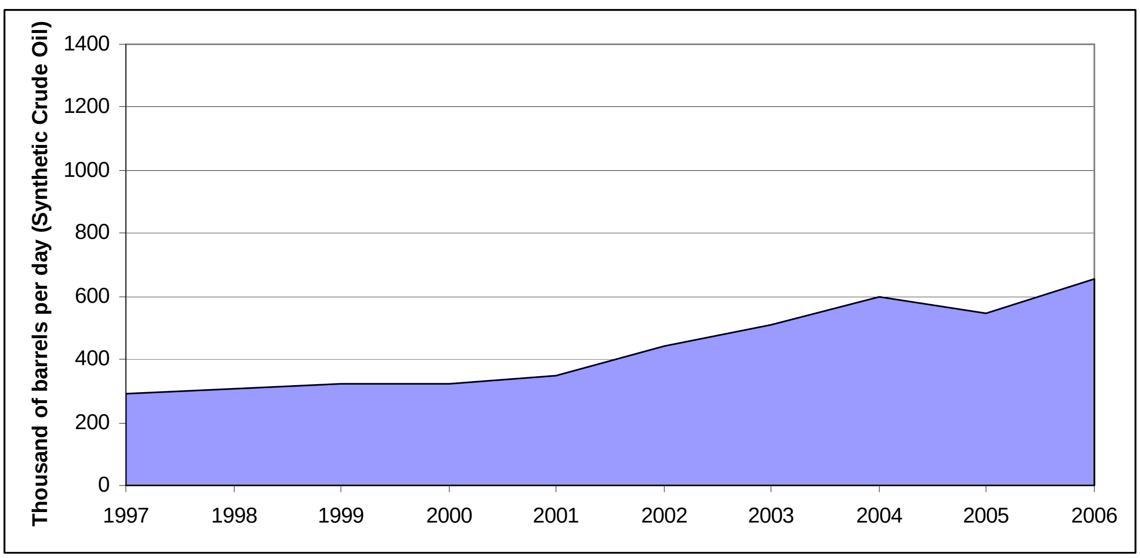
Figure 2.2
Historical Gross Crude Bitumen Production by Production Method



SOURCE: *Statistical Series ST-98,* Alberta Energy and Utilities Board.

Synthetic crude oil (SCO) production reached 210 thousand BPD (33.4 thousand m^3/d) in 1990 and 658 thousand BPD (104.6 thousand m^3/d) in 2006, as presented in Figure 2.3.

Figure 2.3
Historical Synthetic Crude Oil Production



SOURCE: *Statistical Series ST-98,* Alberta Energy and Utilities Board.

2.3 Oil Sands Extraction Technologies (beyond 2008)

For the purpose of the study, the following bitumen extraction methods were used to assist with the formulation of a CERI Reference Case for each method. The reference case was relied upon for the studies assessment of various supply costs, given different alternative technologies.

In Situ
- Cyclic Steam Stimulation (CSS)
- Steam-Assisted Gravity Drainage Stand-alone (SAGD)

Mining, Extraction, and Upgrading
- Mining and Extraction Project (Stand-alone)
- Mining and Extraction Project with Integrated Upgrader

Merchant Upgrader (Stand-alone)

2.4 Oil Sands Energy Requirements

A rule-of-thumb commonly used in the industry is that 1.0 Mcf (1.05 GJ) of natural gas is required to produce a barrel of bitumen; however, gas requirements vary depending on the recovery technology, the quality of the reservoir, steam injection and bitumen production cycles, and the efficiency of the steam generation equipment. This rule-of-thumb is appropriate for most in situ recovery operations (i.e., dry steam-oil ratio or SOR of about 2.5), but is too low for less energy efficient operations. A typical SAGD project operates with an average SOR of about 2.5 dry (3.1 wet–wet is based upon 80% steam quality, which means that 20% of a barrel of steam is water and the remaining 80% is steam) and would require 1.02 Mcf (1.07 GJ) of natural gas per barrel of bitumen over the life of the project. A typical CSS project operates, over the life of the project, with an average SOR of about 3.5 wet (2.8 dry) and would require 1.14 Mcf (1.20 GJ) per barrel. However, in situ projects typically use produced associated gas to meet part of the fuel requirements (15 percent is a common value for CSS while 1 percent is common for SAGD). Consequently, a value of 1.0 Mcf (1.05 GJ) per barrel is an appropriate approximation of thermal recovery offsite natural gas requirements.

Table 2.2 summarizes the natural gas requirements and purchases.

Table 2.2
Oil Sands Natural Gas Requirements and Purchases

	Natural Gas Requirements Mcf/bbl (GJ/bbl)		Natural Gas Purchases Mcf/bbl (GJ/bbl)	
	No Cogeneration	Cogeneration	No Cogeneration	Cogeneration
CSS	1.1 (1.2)	2.0 (2.1)	1.0 (1.1)	1.8 (1.9)
SAGD	1.0 (1.1)	1.6 (1.7)	1.0 (1.1)	1.6 (1.7)
Mining & Extraction		0.5 (0.5)		0.5 (0.5)
Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		0.9 (0.9)		0.6 (0.6)
Integrated Mining & Extraction and Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		1.0 (1.0)		0.7 (0.7)

SOURCE: CERI.

Table 2.3 summarizes the electricity requirements for in situ projects operating at capacity (30,000 BPD (4,769 m^3/d)), mining projects (100,000 BPD (15,898 m^3/d)), upgraders (100,000 bbl SCO/d (15,898 m^3 SCO/d)), and integrated projects (100,000 bbl SCO/d) (15,898 m^3 SCO/d). The requirements are based upon the Cogeneration Study. Mining projects and upgraders are assumed to meet their steam needs and purchase any electricity that is not met by the cogeneration unit.

Table 2.3
Oil Sands Electricity Requirements and Purchases

		Electricity (MWh/d)			
		Demanded	Purchased	Generated	Sold
CSS	No Cogeneration	300	300	0	0
	Cogeneration	300		4,195	3,895
SAGD	No Cogeneration	300	300	0	0
	Cogeneration	300	0	3,830	3,530
Mining & Extraction	Cogeneration	1,200		1,928	728
Upgrading	Cogeneration	800	448	352	0
Integrated Mining & Extraction and Upgrading	Cogeneration	2,180	1,118	1,062	

SOURCE: CERI 2006 Cogeneration Study.

2.5 Estimating Capital and Operating Costs for Oil Sands Projects

From early 2000 to 2007, updated capital cost information for some projects—notably CSS—has not been readily available. This is a result of corporate planning policies and also partly due to the changing input cost environment in Alberta. Estimating the rate of capital cost inflation over a period of time is challenging, since no Alberta index for measuring oil sands capital and operating cost inflation exists. In October 2007, CERI performed a confidential survey of SAGD operators for a private client, "Survey". From this Survey, CERI concluded that capital costs over the period 1999 to 2006 increased by 59 percent, or 8.4 percent per year on average. Over the same period of time, the Nelson-Farrar Refinery Cost Index ("Index") indicates that capital costs for a Refinery increased by 31.4 percent over the same period. Over the same period of time, CNRL's Horizon project saw capital costs rise over 42 percent, including their most recent 2007 estimate,[8] capital costs are up 81 percent. The CNRL estimates do include a contingency factor. From 2006 to 2007 the Index indicates a capital cost increase of 6 percent. Anecdotal evidence in Alberta suggests that some of the capital and labour cost increases attributable to oil sands projects are a direct result of local factors. From 1999 to 2006 the Survey based estimate is 27 percent higher than the Index. Since CERI's estimates are derived from local market participants they should adequately represent the Alberta issues.

[8] http://www.cnrl.com/client/whats_new/867/879/0212_horizonupdate.pdf

Our Survey indicated that operating costs (excluding fuel, taxes and royalties) have also risen over the period by an average of 11.2 percent per year. Detailed capital cost assumptions and the projects used to form the assumptions can be found in the study.

2.6 Greenfield Supply Cost Methods

Supply costs for the production of crude bitumen incorporating cogeneration facilities are provided for each of the recovery technologies: CSS, SAGD, mining and extraction, mining and extraction and upgrading, and stand-alone merchant upgrading. It is assumed that a cogeneration unit is included in the capital and operating costs for non in situ recovery technologies. The supply costs for in situ technologies include a no cogeneration case, to reflect future Greenfield projects without cogeneration. The cogeneration facilities are assumed to follow the thermal, or steam, load of the project.

Electricity produced by the cogeneration unit is consumed by the oil sands project, with any excess electricity being sold into the Alberta electricity system at an assumed electricity price. This price is in real terms and fixed over the life of the project. The revenues from the excess electricity generated are accounted for in the calculation of the supply costs.

The bitumen supply cost is the constant dollar price needed to recover all capital expenditures, operating costs, royalties, taxes, and earn a specified return on investment. For this study, supply costs are calculated in constant 2007 dollars, and reflect pre-2009 royalty rates.

The supply cost estimates presented here have been calculated using cash flow models that solve for the constant dollar price needed for favourable project economics. The supply cost includes an annual discount rate of 10 percent (real). This is equivalent to an annual return on investment of 12.2 percent (nominal) based on the assumed inflation rate of 2.2 percent per annum.

On July 1, 2007, the Alberta Government enacted their climate change plan, as detailed in Bill 3, “Climate Change and Emissions Management Amendment Act, 2007”. This plan involves applying a levy to large final emitters – as defined as those emitting over 100,000 tonnes (T) of carbon dioxide equivalent per year – a sum of CDN$15.00/tonne. The levy serves as a contribution to a technology fund, whose purpose is to provide funding for research into emissions reducing technologies. While the province has yet to deploy a trading mechanism/market for carbon, our model incorporates this $15.00/tonne levy for emissions over the 100,000 limit. No assumptions are made to reflect improving technology over-time. For the purpose of the study, only emissions produced in the combustion of natural gas are included in our emissions compliance cost calculation. The Reference Cases make no assumptions pertaining to improved efficiencies – emissions reductions – per unit of output over the life of the project.

Tables 2.4 to 2.6 present the assumptions used in the calculation of the supply cost, while Tables 2.7 to 2.10 provide the Reference Case supply cost results for each extraction technology.

Table 2.4
Financial Assumptions

Timing		
Base Year	January 1	2007
Start of Construction	January 1	2008
Start of Operations	January 1	2010/2011 Mine
Termination of Operations	December 31	2040/2011 Mine
Year of Currency Inputs		2007
Economic Parameters		
Project Rate of Return (Discount Rate)	%/year, Real	10.0%
Cost Inflation	%/year, Nominal	2.2%
Exchange Rate	US$/C$	0.95
Tax Rates		
Federal Rate	Effective January 1, 2010	19.0%
Federal Surcharge	Eliminated January 1, 2008	0.0%
Alberta Rate	Effective January 1, 2005	10.0%
Alberta Surcharge		0.0%
Royalties		
Minimum Rate		1.0%
Rate after Payout		25.0%
Allowable Return before Payout	Long Term Bond Rate	5.5%
Carbon Dioxide Emissions		
CO_2e Emissions Factor	kg/GJ	51.4
CO_2e Compliance Costs	Real C$ / tonne*	$15.0

*The compliance cost has been assumed as real over the life of a project. A nominal compliance cost would continue to decline over the life of the project, being relatively worthless at the end of the project.

Table 2.5
In Situ Design and Cost Assumptions

		CSS Cogen	CSS	SAGD Cogen	SAGD
Stream Day Capacity	b/d of bitumen	30,000	30,000	30,000	30,000
Capital Expenditures[a]					
Initial Capital	2007 C$million	1,036	888	922	776
Sustaining Capital	2007 C$million/year	26.6	25.3	19.9	18.4
Operating Working Capital	Days payment	45	45	45	45
Abandonment and Reclamation	% of Total Capital	2.0	2.0	2.0	2.0
Operating Costs (Excluding Energy)[b]					
Fixed Operating Costs	2007 C$million/year	85.67	77.73	72.63	65.37
Variable Operating Costs	2007 C$/b	8.6	7.8	5.7	5.0
Energy Purchased (Stream Day)					
Natural Gas Purchased	GJ/d	55,800	31,500	51,600	32,100
AECO-C Gas Price[c]	C$/GJ	Forecasted	Forecasted	Forecasted	Forecasted
Field Premium	C$/GJ	$0.3	$0.3	$0.3	$0.3
Electricity (Stream Day)					
Electricity Price[d]	2007 C$/MWh	$62.7	$62.7	$62.7	$62.7
Electricity Purchased	(MWh/day)	0	300	0	300
Electricity Generated	(MWh/day)	4,195	0	3,830	0
Electricity Sold	(MWh/day)	3,895	0	3,530	0

[a]In order to differentiate in situ, cogeneration projects from their non-cogeneration counterparts, information derived from CERI's Cogeneration Study is used—inflated from 2004 dollars to 2007 dollars.

[b]Based upon analysis performed for a private client and our survey results, CERI has estimated the in situ operating costs as follows: Fixed operating costs are assumed to be 8.75 percent of total capital costs, while variable operating costs are based upon the costs associated with maintaining wells—assumed to be C$477,000 per well per year.

[c]CERI has forecast natural gas prices, based upon publicly available forecasts by Sproule, the U.S. EIA, ARC Financial and our own internal data. These forecasts (including historic data) are shown in Figure 3.1 in the study.

[d]The electricity price has been fixed at $62.7 (real) over the life of the project. We recognize that the forecasted natural gas price and changing environment for carbon compliance costs could drive this price higher in the future, and impact the financial benefits/risks from cogeneration.

Table 2.6
Mining and Extraction, Stand Alone Upgraders, and Integrated Cost Assumptions

		Mining and Extraction	**Stand Alone Upgrader**	**Integrated Mining and Extraction and Upgrader**
Stream Day Capacity	b/d of bitumen	100,000	115,000	115,000
Stream Day Capacity	b/d of SCO		100,000	100,000
Capital Expenditures				
Initial Capital	2007 C$ million	4,808	4,598	10,845
Sustaining Capital	2007 C$million/year	24.1	21.1	46.0
Operating Working Capital	Days payment	45	45	45
Abandonment and Reclamation	% of Total Capital	2.0	2.0	2.0
Operating Costs (Excluding Energy)[a]				
Fixed Operating Costs	2007 C$million/year	118.9	124.2	243.1[b]
Variable Operating Costs	2007 C$/b	6.3	3.4	9.7[c]
Energy Purchased (Stream Day)				
Natural Gas Purchased	GJ/d	54,211	81,436	83,213
AECO-C Gas Price[d]	C$/GJ	Forecasted	Forecasted	Forecasted
Field Premium	C$/GJ	$0.3	$0.3	$0.3
Electricity (Stream Day)				
Electricity Price[e]	2007 C$/MWh	$62.7	$62.7	$62.7
Electricity Purchased	(MWh/day)	0	448	1,128
Electricity Generated	(MWh/day)	1,928	352	1,928
Electricity Sold	(MWh/day)	728	0	

[a]Operating costs are based upon information from CERI's 2004 Oil Sands Study and feedback from Industry. Operating costs have been inflated from 2002 dollars to 2007 dollars.

[b]C$118.88 is royalty applicable and associated with the mine.

[c]C$6.26 is royalty applicable and associated with the mine.

[d]CERI has forecast natural gas prices, based upon publicly available forecasts by Sproule, the U.S. EIA, ARC Financial and our own internal data. These forecasts (including historic data) are shown in Figure 3.1 in the study.

[e]The electricity price has been fixed at $62.7 (real) over the life of the project. We recognize that the forecasted natural gas price and changing environment for carbon compliance costs could drive this price higher in the future, and impact the financial benefits/risks from cogeneration.

Table 2.7
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Cold Lake CSS Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	14.02	12.57
Operating Working Capital	0.25	0.22
Fuel	8.96	5.06
Other Operating Costs	15.53	14.80
Abandonment Costs	0.01	0.01
Royalties	2.06	1.81
Income Taxes	2.01	1.74
Emissions Compliance Costs	1.25	0.65
Electricity Sales	8.14	0.00
Total Supply Cost	35.95	36.87

Table 2.8
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Athabasca SAGD Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	11.99	10.24
Operating Working Capital	0.23	0.20
Fuel	10.53	6.55
Other Operating Costs	12.90	12.16
Abandonment Costs	0.02	0.01
Royalties	2.32	1.89
Income Taxes	2.49	2.04
Emissions Compliance Costs	1.25	0.72
Electricity Sales	7.38	0.00
Total Supply Cost	34.36	33.81

Table 2.9
Bitumen Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	16.78
Operating Working Capital	0.32
Fuel	3.05
Other Operating Costs	9.67
Abandonment Costs	0.02
Royalties	3.04
Income Taxes	3.04
Emissions Compliance Costs	0.40
Electricity Sales	0.46
Total Supply Cost	35.86

Table 2.10
SCO Supply Cost at Plant Gate
100,000 barrel per day Stand Alone Upgrader Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	15.87
Operating Working Capital	0.26
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	3.01
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	31.84

2.6.1 Upgrading SAGD Bitumen Supply Cost Sensitivity

Stand-alone upgraders will require a supply of bitumen. In this analysis we consider a stand-alone upgrader purchasing Athabasca quality raw bitumen from a SAGD project. The SAGD project is assumed to not use cogeneration, while the upgrader relies upon cogeneration for some of their electrical needs. It is assumed the cost to transport bitumen from the field to the upgrader[9] is C$1.0/bbl of raw bitumen.

Table 2.11
SCO Supply Cost at Plant Gate
100,000 barrel per day Upgrader Project:
Athabasca Quality Bitumen Sourced from SAGD

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	
Return on Investment	Included
Feedstock (Bitumen)	40.02
Fixed Capital	15.87
Operating Working Capital	0.26
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	2.64
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	71.84

2.6.2 Upgrading Mined Bitumen Supply Cost Sensitivity

In this analysis we consider a stand-alone upgrader purchasing raw bitumen from a mining project. Both the upgrader and the mine use cogeneration on-site. Electricity sales from the mine are accounted for in the mining and extraction projects supply cost. It is assumed the cost to transport bitumen from the field to the upgrader is C$1.0/bbl of raw bitumen.

[9] Implicit within this assumption is that the upgrader is located near Edmonton, e.g. the "Industrial Heartland" in Alberta.

Table 2.12
SCO Supply Cost at Plant Gate
100,000 barrel per day Upgrader Project:
Athabasca Quality Bitumen Sourced from Mine

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	
Return on Investment	Included
Feedstock (Bitumen)	42.38
Fixed Capital	15.87
Operating Working Capital	0.25
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	2.36
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	73.55

2.6.3 Integrated Mining and Extraction and Upgrading Supply Cost Reference Case

Integrated Mining and Extraction and Upgrading projects should receive some economies of scale on construction, maintenance and operating costs, and energy use. However, as has previously indicated in the assumption tables, stated the capital cost numbers for our integrated project are 20 percent higher than stand alone projects. Under these assumptions, we would anticipate the supply cost to exceed that of the stand alone projects.

Table 2.13
SCO Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	**Cogeneration**
Return on Investment	Included
Fixed Capital	37.31
Operating Working Capital	0.67
Fuel	4.67
Other Operating Costs	18.24
Abandonment Costs	0.03
Royalties	4.26
Income Taxes	6.85
Emissions Compliance Costs	0.87
Electricity Sales	0.00
Total Supply Cost	72.91

2.7 Production Profile (Projection to 2030)

The oil sands industry's primary drivers of greenhouse gas (GHG) emissions growth over the coming decades will be a direct result of the success of oil sands developers. A robust outlook for oil sands expansions will result in an increased consumption of natural gas, which in turn will result in higher emissions. Under the current environment frameworks in Alberta and Canada, oil sands producers can increase their emissions, subject to compliance costs – but no emissions limit.

Projections of bitumen and SCO production from Canada's oil sands are typically based on the summation of all announced projects, with a wide variety of assumptions pertaining to the projects schedule and delays, technology, and state of development. CERI decides which projects are delayed and the rate at which production comes on stream, based upon our past experience with monitoring the progress of oil sands projects.

2.7.1 Reference Case Projections (Production & Capital Investment)

There are a number of factors that will likely hamper the announced expansion plans of oil sands operators, and in turn constrain the planned growth in production capacity. These include:

- future world oil supply/demand;
- availability of capital;
- availability and productivity of skilled construction workers;
- infrastructure limitations, such as pipeline availability and upgrading capacity;
- technology development;
- environmental concerns; and
- geopolitical effects.

Due to these factors, not all projects included in the Unconstrained Projection – which is a projection that assumes all projects go ahead as planned: this projection is included in the study – may begin operations as anticipated, or even go ahead into operation. We developed two Constrained Projections by applying various delays and probabilities to each of the announced projects, relative to their planned start-up dates and production capacities. The delays and probabilities applied correspond to the projects position in the regulatory process. Projects further along the regulatory process are given small delays and high probabilities of proceeding to their announced production capacity.

Upfront delays, measured in years, postpone project start-up dates by the specified amounts of time. This scenario for delays is reflected in the *Constrained Projection* and is provided in the study.

Multipliers, or probabilities, are applied to the planned production capacity to get an adjusted production projection. These multipliers are the estimated probabilities of projects actually going into operation. They are applied to planned production capacity in each category to derive expected production.

The *Constrained Projection with Double Delays and Capacity Curtailments* (also referred to as the *Projection Reference Case*) takes into account delays and probabilities—or capacity curtailments.

Delays and probabilities (where appropriate) for each phase of the regulatory approval process are based upon reasonable estimates of how long each phase could take, and are as follows:

- projects operating or under construction - 1-year time delay (2-years under the double delay Projection) for mining projects, no time delay for in situ projects; 100 percent probability multiplier for production;
- projects approved – 1-year time delay (2-years under the double delay Projection); 90 percent probability multiplier for production;
- projects in the application process - 3-year time delay (6-years under the double delay Projection) for mining projects and 1-year time delay (2-years under the double delay Projection) for in situ projects; 80 percent probability multiplier for production;
- projects at disclosure stage - 4-year time delay (8-years under the double delay Projection) for mining projects and 2-year time delay (4-years under the double delay Projection) for in situ projects; 75 percent probability multiplier for production; and
- projects identified as announced - 4-year time delay (8-years under the double delay Projection) for mining projects and 3-year time delay (6-years under the double delay Projection) for in situ projects; 60 percent probability multiplier for production.

The phases of the regulatory process are defined as:

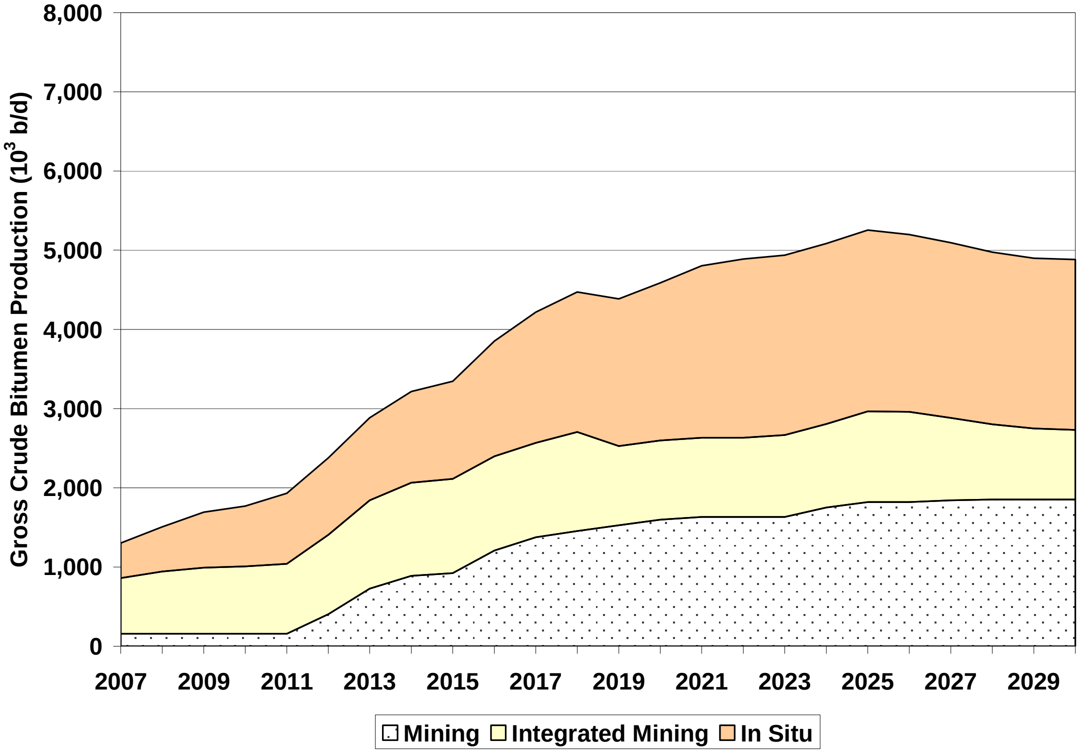
- operating – Construction has been completed and start-up of operation has begun;
- under construction – Construction of the facilities has begun;
- approved – Application has been approved by the appropriate regulatory bodies;
- application process – Oil Sands Application and Environmental Impact Assessment (EIA) has been filed with the AEUB and Alberta Environment;
- disclosure – Disclosure document for the project defining the terms of reference of the EIA has been released; and
- announced – Operators' plans for development have been publicly announced.

Applying these adjustments to the Unconstrained Projection allows us to form alternate projections - ones that, given historic capital spending and annual capacity additions, are attainable under projected economic conditions.

2.7.2 Projection Reference Case

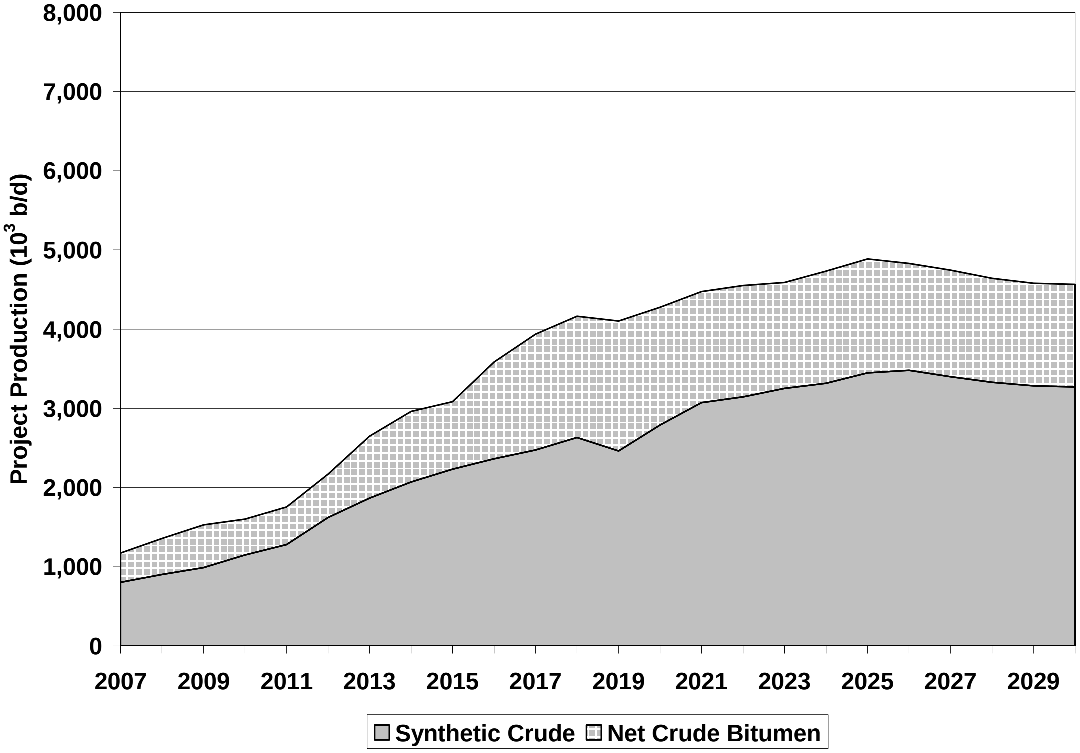
The Projection Reference Case with Capacity Curtailments and Double Delays reaches a total bitumen production of just under 5.0 MBPD (million barrels per day) by 2030, as indicated below.

Figure 2.4
Projection Reference Case, Gross Crude Bitumen Production



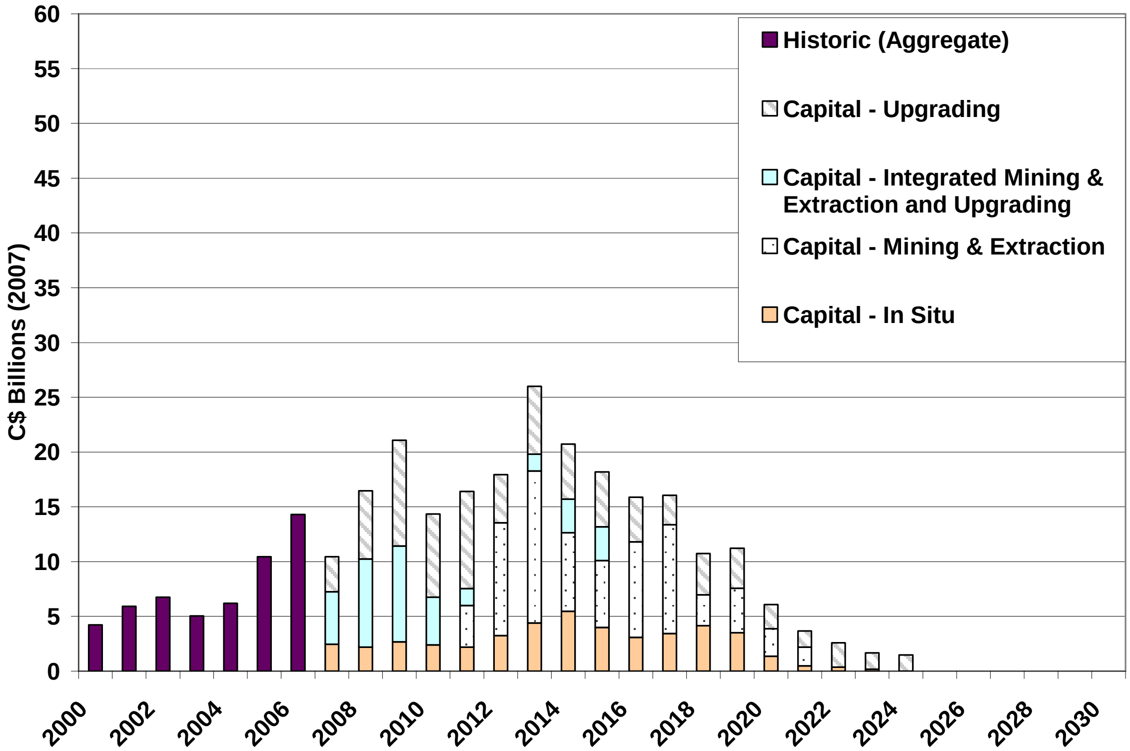
Under this projection, crude bitumen upgraded in Alberta will increase from 929,000 BPD in 2007 to 3.6 MBPD in 2030. As a result, synthetic crude oil production will increase from 802,000 BPD in 2007 to 3.3 MBPD in 2030. Net bitumen production (not upgraded) will increase from 390,000 BPD in 2007 to 1.3 MBPD in 2030. Total net production (net bitumen plus synthetic crude oil) will increase from 1.2 MBPD in 2007 to 4.6 MBPD in 2030. SCO production is graphically presented in Figure 2.5.

Figure 2.5
Projection Reference Case, SCO Bitumen Production



Construction spending is estimated for this projection, using the same initial capital spending values used to derive supply costs. Constrained capital spending is shown in Figure 2.6, paralleling the growth in oil sands production. The lack of spending beyond 2024 reflects a lack of incremental growth in production and therefore investment.

Figure 2.6
Projection Reference Case, Estimated Capital Spending for Greenfield Projects



2.7.3 Projection Reference Case – Oil Sands Natural Gas Consumption

The oil sands industry consumes substantial amounts of natural gas during production and upgrading activities. In 2006, the oil sands industry accounted for approximately 1.0 Bcf/d of natural gas demand, slightly more than 40 percent of Alberta's total natural gas demand.[10] As production levels increase, natural gas consumption will also increase, unless low GHG technologies are implemented.

Thermal and electricity needs of mining and extraction projects and upgraders will be met through cogeneration units, designed to follow the thermal load of the project. Whether they burn natural gas or another feedstock remains to be seen over the projection period. In situ projects are a different matter. Recent applications include the intent to move forward with cogeneration. However, this introduces additional risk to the in situ operator: the open electricity market and increased exposure to natural gas price volatility, if excess electricity is produced.

For the purpose of this section, we will assume that in situ projects with operating dates beyond 2007 do not use cogeneration; those prior to 2007 will be assumed to include cogeneration (following the thermal requirements of the oil sands project) with the exception of EnCana's Christina Lake and Foster Creek projects, which do not use cogeneration.

[10] AEUB ST-98, AND CAPP.

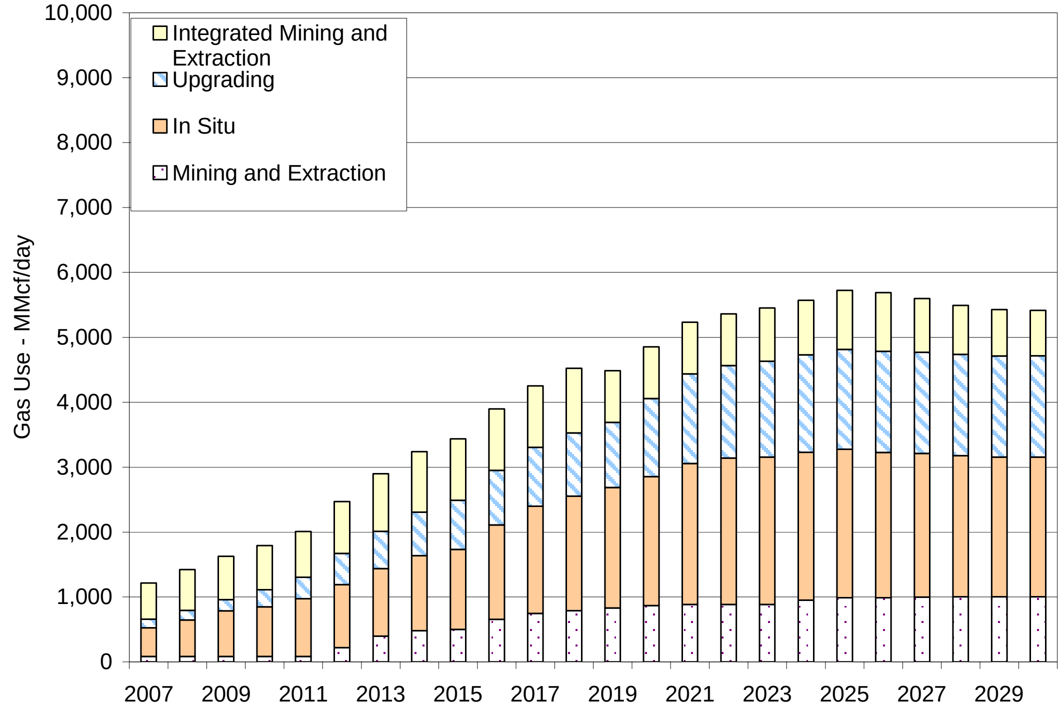
Table 2.14 is a reproduction of Table 2.2 and presents natural gas consumption by oil sands technology.

Table 2.14
Oil Sands Natural Gas Requirements and Purchases

	Natural Gas Requirements Mcf/bbl (GJ/bbl)		Natural Gas Purchases Mcf/bbl (GJ/bbl)	
	No Cogeneration	Cogeneration	No Cogeneration	Cogeneration
CSS	1.1 (1.2)	2.0 (2.1)	1.0 (1.1)	1.8 (1.9)
SAGD	1.0 (1.1)	1.6 (1.7)	1.0 (1.1)	1.6 (1.7)
Mining & Extraction		0.5 (0.5)		0.5 (0.5)
Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		0.9 (0.9)		0.6 (0.6)
Integrated Mining & Extraction and Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		1.0 (1.0)		0.7 (0.7)

Projections for natural gas purchases are provided in Figure 2.7, which represents the oil sands industry relying completely on natural gas over the projection period.

Figure 2.7
Total Natural Gas Purchases – CERI Reference Case



When all projects prior to 2007 use natural gas-fuelled cogeneration (with the exception of EnCana, which has no cogeneration) and all new in situ projects after and including 2007 rely on purchased electricity, the total amount of natural gas purchased will almost reach 6,000 MMcf/day by 2025. This represents an increase of over 400 percent from current levels.

2.8 Oil Sands Emissions

To avoid presenting a bias, CERI is relying upon the CO_2e emissions resulting from the burning of a pipeline spec natural gas. We make no assumptions pertaining to "cleaning" of the flue emissions prior to release into the atmosphere. This has been done intentionally since it will provide for a clear comparison with emissions from the alternative fuel sources.

Natural Gas Emissions Factors for Electric Utilities, as reported by Environment Canada, in g/m3 of natural gas[11] are listed in Table 2.15, where CO_2 is 1891, CH_4 is 0.49, and N_2O is 0.049 g/m^3 of natural gas. Using CAPP's reported GWP factors of 1 for CO_2, 21.0 for CH_4 and 310 for N_2O we calculate a CO_2e for natural gas equal to 1.92 kg/m^3, which equates to a GWP for natural gas of approximately 51.36 kg CO_2e/GJ:

[11] Assumed combustion efficiency of 99.5 percent.

Table 2.15
Natural Gas – Global Warming Potential

	Emissions (g/m3)	Global Warming Potential
CO2	1891	1
CH4	0.49	23
N20	0.049	296
		1.92 kg / m3
		51.36 kg CO2e/GJ

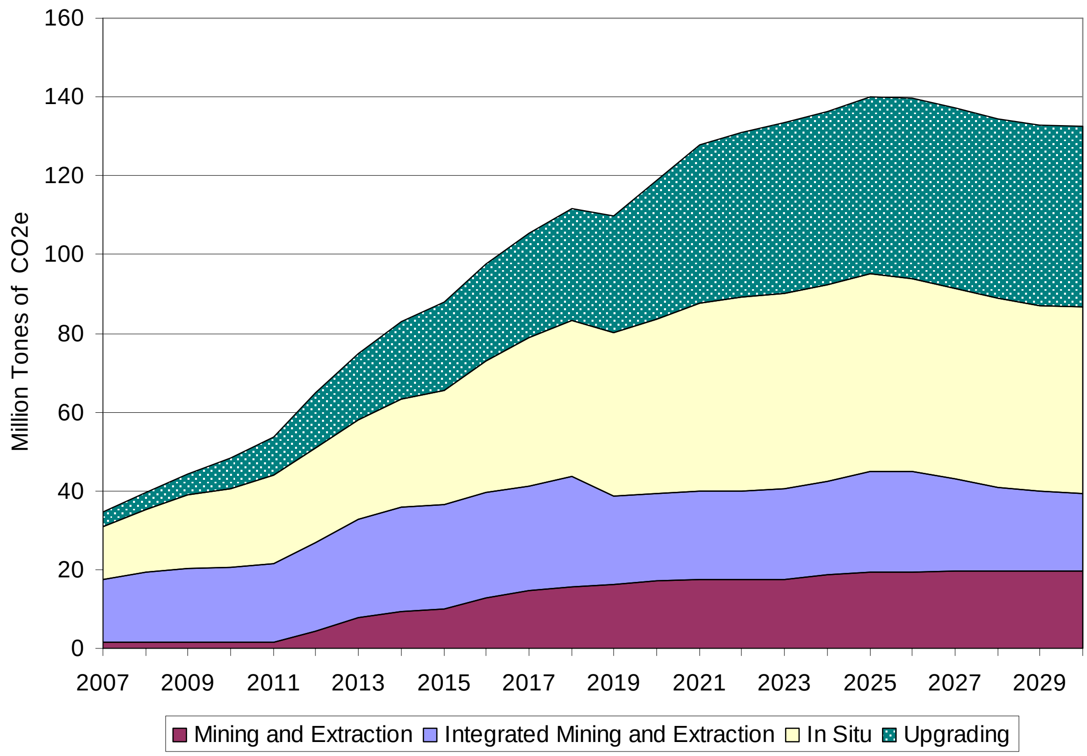
Throughout the rest of this summary report we will rely on this GWP value to determine the amount of CO_2e emissions produced by the oil sands industry.

2.8.1 Emissions Projections

In order to understand the emissions from the oil sands we need to first look at the total direct emissions—associated with the use of natural gas (purchased and produced, where produced gas is assumed to have the same characteristics as the purchased gas). A more complete understanding of the oil sands emissions could involve a life-cycle assessment (LCA) that would account for the emissions from construction and operations (including vehicle fleets).

The direct emissions are shown in Figure 2.8 and, not surprisingly, rise along with the projected increase in oil sands production and natural gas use as shown previously.

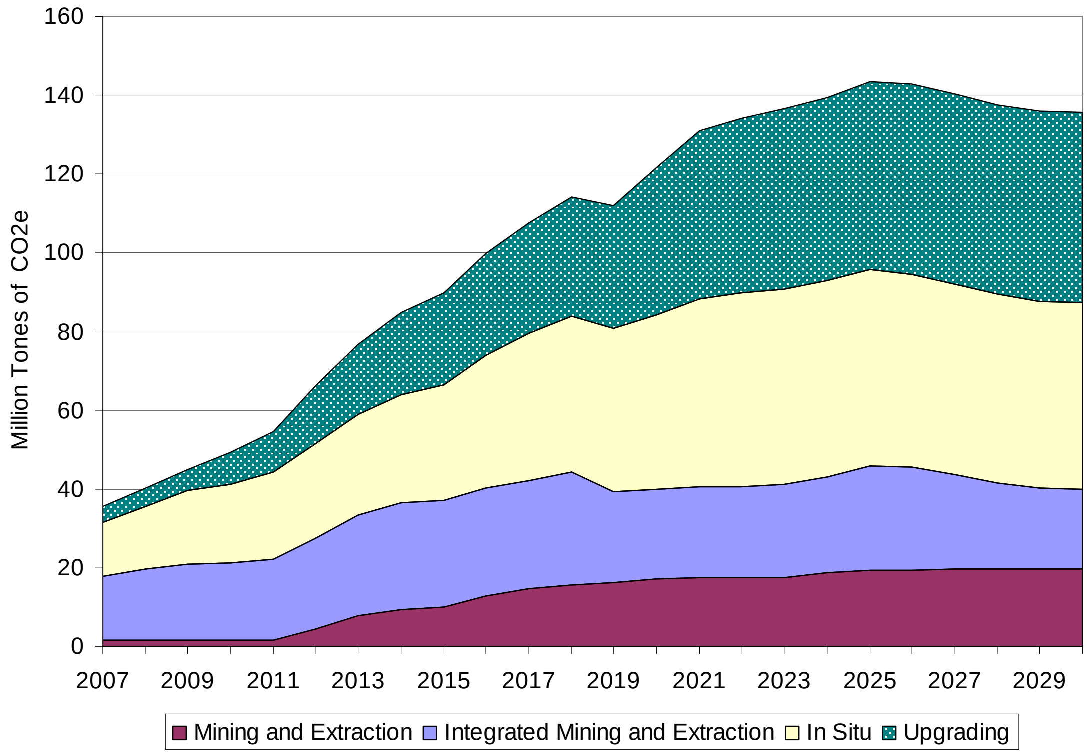
Figure 2.8
Reference Case Direct Emissions Projection



These emissions are based upon the required natural gas for the oil sands. Since this gas is used for the production of two sources of energy (thermal and electric) from a single fuel source, it is inherently more energy efficient than having two stand alone facilities producing the same outputs.

For those oil sands projects requiring purchased electricity, we have assumed that the emissions from the facility would reflect the Alberta grid intensity. Since Alberta's electricity system is heavily weighted to coal-fired power plants, the grid intensity is higher than if it was purchased from a natural gas (or cogeneration) facility. A grid intensity of 0.65 T of CO_2e / MWh has been assumed.

Figure 2.9
Direct and Indirect Emissions



(THIS PAGE INTENTIONALLY LEFT BLANK)

CHAPTER 3
ALTERNATIVE FUELS AND CCS

By reducing emissions to a level equal to or below that of conventional crude oil in Canada, the oil sands could move towards the production of what we call, "***Green Bitumen***". The study considered three options for emissions reduction: nuclear, gasification of coal or coke with carbon capture and storage at the gasifier, and lastly carbon capture and storage at an oil sands project.

3.1 Nuclear Energy

Nuclear reactors produce, contain and control the release of energy from the splitting of U235 atoms. In electric power plants, this energy is used to heat water for the purpose of steam generation. The steam, in turn, drives the turbine-generators to make electricity. The fissioning of uranium is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas or oil is used as a source of heat in a fossil fuel power plant.

In spite of the influx of many complex engineering designs over the past several decades, there are two main nuclear power types: those moderated by light water and those moderated by heavy water. Light water reactors are divided further into Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). These reactor types comprise sixty-one percent and twenty-one percent, respectively, of reactor types currently used in the world.

Canada's CANDU – Canada Deuterium Uranium – is categorized as a Pressurized Heavy Water Reactor (PHWR) and makes up 100 percent of reactors used in Canada, and 10 percent of the reactors used worldwide.

3.1.1 Advanced CANDU Reactor (ACRs)

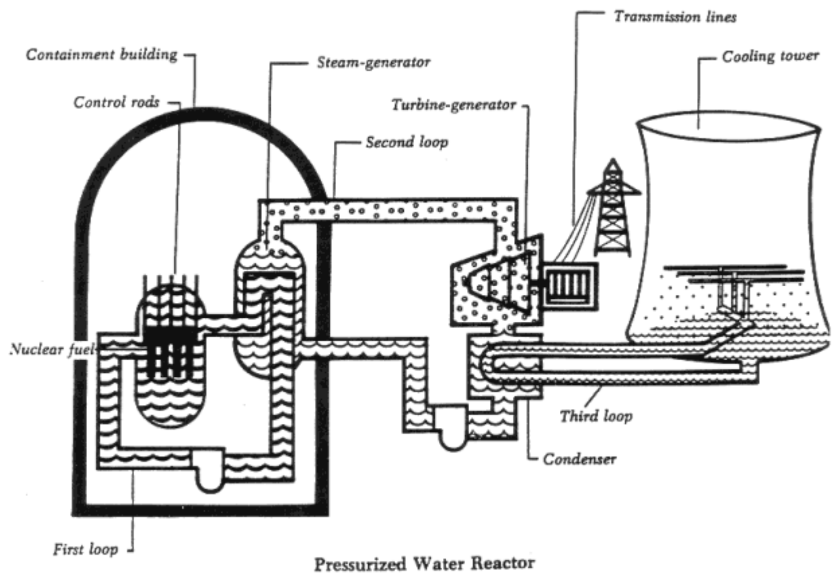
The ACR-1000 is the latest in the evolution of CANDU technology from Atomic Energy of Canada Limited (AECL). The ACR-1000 is a Generation III+, 1200 MWe class heavy water reactor. While the ACR has never been built (i.e., it is a "paper reactor"), AECL is confident that it can be successfully constructed, as it is a progression from the CANDU 6 reactors.

Since there are no ACRs in commercial operation, a track record of performance data is not available. AECL expects that an ACR, like a PWR of recent design, will achieve a 95 percent capacity factor over its lifetime. The similarity in capacity factor could be perceived as negating the benefits associated with on-line refuelling.

3.1.2 Pressurized and Boiling Water Reactor (PWR and BWR)

The PWR is the most common type of nuclear reactor in the world, followed by the BWR. All nuclear reactors in France employ PWR technology except for one fast breeder. In the BWR, the water heated by the reactor core turns directly into steam in the reactor vessel as it is allowed to boil. It is then used to power the turbine-generator. In a PWR, the water passing through the reactor core is kept under pressure so that it does not turn to steam at all, but instead remains liquid. The PWR is distinguished by having a primary cooling circuit and a secondary circuit. The former allows the pressurized water to be circulated in a closed system of pipes. During the process, the heat from this circuit heats up the secondary circuit. Because the secondary circuit has less pressure, the water within it is permitted to boil and the steam powers the turbine. The design of the PWR is depicted in Figure 3.1.

Figure 3.1
Diagram of a PWR Plant



SOURCE: National Research Council website, www.nrc.gov/reading-rm/basic-ref/teachers/pwr-schematic.html

The PWR and BWR use enriched uranium (4-5 percent U235), rather than low-enriched uranium that fuels the ACR. In addition, while ACR technology employs heavy water as a moderator and light (ordinary) water as a coolant, the PWR uses ordinary water as both a coolant and a moderator.

Other technological differences include the use of a pressure vessel instead of the ACR's horizontal pressure tubes. The former cannot, however, be refuelled on-line. The enriched uranium is fabricated into long zirconium-alloy tubes. While the ACR has simple short fuel bundles, PWR technology uses a full-length fuel string design.

For the purpose of this analysis CERI will rely upon information for the EPR 1600. The EPR-1600 is a generation III+ PWR reactor that is under construction in Europe, and is not a "paper reactor".

3.1.3 Canadian Regulations on Nuclear Power Plants

Nuclear activities in Canada are regulated by the Federal Government, under the direction of the Canadian Nuclear Safety Commission (CNSC). The CNSC describes itself as the "nuclear energy and material watchdog in Canada",[12] and is responsible for the regulation of nuclear power reactors, uranium mines and mills, fuel fabrication and processing facilities, and waste management facilities.

Any new reactors would follow the regulatory guidelines detailed in the February 2006 document, "*Licensing Process for New Nuclear Power Plants in Canada, INFO-0576*". The process requires a proponent to apply for a license for site preparation, construction, and operation of a nuclear reactor. In addition, a positive decision on an Environmental Assessment (EA) under the *Canadian Environmental Assessment Act* is required in order for a new nuclear reactor to be built in Canada. This process is anticipated to take anywhere from 18 to 36 months from start to finish, depending on a number of factors, outlined in the 2006 document. The licenses can be applied for in a parallel process, while the EA is being carried out. For the purpose of our supply cost assessment for nuclear, a 36-month regulatory process has been assumed – both the ACR and EPR are "new" technologies that have not yet undergone the CNSC's regulatory process. It is possible that any new reactor proposed in Alberta could be delayed longer than the 36 month window. It is uncertain as to how many applications the CNSC can handle at any given time, while maintaining sufficient staffing levels. A 36-month window should be considered optimistic for any reactor on a Greenfield site.

3.1.4 Harnessing Nuclear Energy to Exploit the Oil Sands

In May 2003, CERI released a study entitled "Comparative Economics of Nuclear and Gas-Fired Steam Generation for SAGD Applications".[13] CERI conducted a comparative assessment using cost data from 2002 for gas-fired steam and electricity facilities (common in the oil sands region), and data provided by Canada's government-owned nuclear vendor, Atomic Energy of Canada Ltd. (AECL).

This assessment was designed to answer some of the key questions as to whether nuclear could work for in situ oil sands production, specifically SAGD. It is important to keep in mind that at the time – and even now – SAGD production is still early in its development. One of the most important issues linking nuclear energy with SAGD production is whether a nuclear facility can produce steam at sufficiently high temperature and pressure. The 2003 study concluded that a nuclear facility (specifically the ACR-700) could indeed provide steam at the required conditions. Furthermore, depending upon how the facility is configured, electricity could also be provided to the in situ operator.

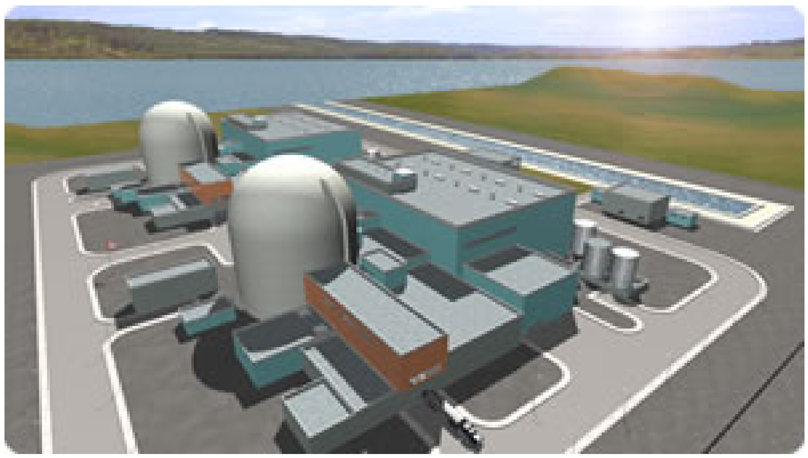
---

[12] http://www.nuclearsafety.gc.ca/eng/about_us/, February 7, 2007
[13] For a copy of the study, please contact CERI.

The smallest commercially available[14] Canadian Nuclear Power Plant (NPP) is the Enhanced CANDU 6 (EC6), two of which were recently built by AECL in Qinshan, China.

The steam delivered from an EC6 would be at 4.6 MPa, 99.8 percent steam quality, and at 260 degrees Celsius.

Figure 3.2
Enhanced CANDU 6[15]



Although the pressure from the facility is inadequate for most oil sands projects, it could work for a few of them. Unfortunately for the EC6, there are no projects currently operating, or scheduled to be operating in the next decade, that will have sufficient steam needs within a 10 to 15 km radius of the nuclear facility.[16] Other nuclear power plants being proposed in Alberta would have higher pressures (which could enable the steam to be transported up to 25 kilometers) and higher output. Depending on the facility, the steam output could be almost double that of a single EC6. The two larger facilities proposed are the ACR-1000 (an evolution of the ACR-700 and the EC6) and a light water reactor from AREVA, the EPR 1600.

The ACR-1000 can provide steam at 275.5 degrees Celsius, 99.9 percent steam quality and at a pressure of 5.9 MPa. The ER-1600 can provide 564 degree Celsius steam at 99.9 percent quality with a pressure of 7.7 MPa.

[14] In this context, commercially is defined as being actively marketed.
[15] http://www.aecl.ca/NewsRoom/Bulletins/E-061211/E01.htm
[16] According to industry experts, the low pressure from this facility reduces the maximum distance the steam can travel to no more than 15 km.

Figure 3.3
ACR-1000[17]

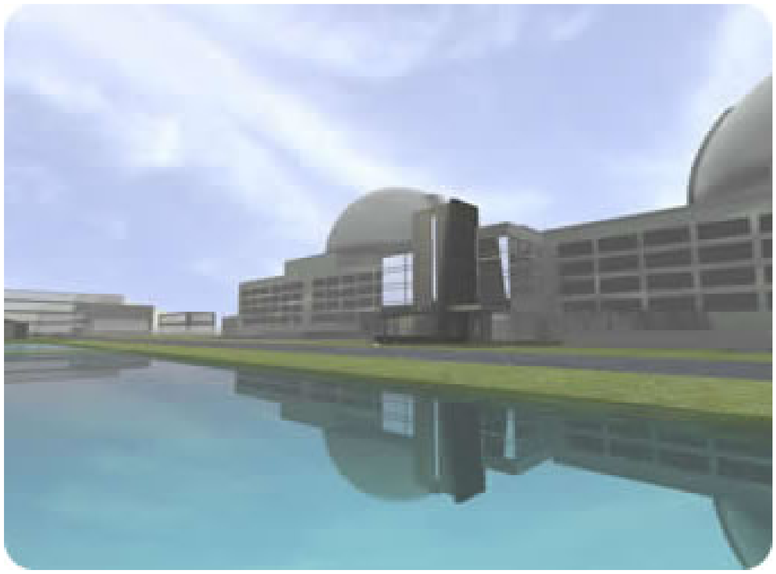


Figure 3.4
EPR 1600[18]

According to the nuclear industry, these facilities could be designed to produce a mixture of outputs, such as steam and electricity. Since this study did not attempt to perform an engineering assessment, it is possible that this type of configuration could bring large scale nuclear power plants into the oil sands to support in situ production.

The twin ACR-1000 and single EPR-1600 have been selected as the NPP for an economic analysis. Both AECL and AREVA have openly commented on their desire to be active in the Alberta market, particularly in the oil sands. Capital cost estimates have been derived from public

[17] Courtesy AECL.
[18] Courtesy AREVA.

sources, and where required, previous CERI reports.[19] Capital costs escalations follow the same technique used for oil sands supply costs.

Due to the uncertainty of estimating costs for NPPs, we have developed a supply cost assessment that is an average of CERI's estimates for the EPR and ACR. For this reason, the output of the facility does not reflect the output of NPPs being marketed today and should be considered illustrative. Supply costs for the EPR and ACR are included in the study.

Starting from the assumption that the NPP would be used for electricity generation, we have the following table of assumptions – where dollar values are considered nominal and reflect 2007:

Table 3.1
Assumptions – Average Base-load Nuclear (Electricity)

	Average Base-load Nuclear
Base year (currency inputs)	2007
Starting year of construction	2011
First year of commercial operation	2014
Discount rate (rate of return) (%)	5
Corporate income taxes (%)	28.5
Annual Inflation Rate (%)	2.2
Net Capacity (MWh)*	1,835
Project life (years)	60
Overnight capital (Million C$)**	5,100
Fixed O&M (C$/MWh net capacity)	0.5
Variable O&M (C$/MWh net capacity)	7.0
Fuel cost (C$/MWh net capacity)***	7.2
Annual capacity factor (%)	95

*Not reflective of an actual facilities output, reflects average of various facilities used in our analysis.

**The overnight capital is assumed to reflect a turnkey fixed price solution. This assumption is the same one used for the capital costs of an oil sands project.

***Fuel costs include an estimate for spent fuel management.

Depending upon the ownership structure, the taxes and required return could be drastically lower than a standard merchant model (with a 10 percent return as was the case for the oil sands) – this would be the case if it was owned by a pension fund, such as the Ontario Teachers Pension Plan, that would be satisfied with a lower rate of return, stable over 30 to 60 years.

Since we are assuming these facilities will operate on a long-term merchant contract with limited risk, a 5 percent rate of return will be used.

[19] O&M and fuel costs are based upon CERI Study, Sept 2005 "Electricity Generation Technologies: Performance and Cost Characteristics", escalated to reflect 2007 dollars.

Table 3.2
Discounted Nuclear Supply Cost at Facility (5% discount)

Supply Cost (Real Canadian dollars per MWh, 2007)	Average Base-load Nuclear
Return on Investment	Included
Fixed Capital	18.7
Fuel	14.3
O&M	14.8
Income Taxes	19.1
Emissions Compliance Costs	0.0
Total Supply Cost	66.9

The ability of nuclear energy to produce electricity (or thermal energy) with zero emissions can act as a long-term hedge against uncertain emissions compliance costs.[20] This hedging opportunity is likely to make nuclear energy an attractive option for oil sands operators.

3.1.5 "Small Scale" Nuclear Energy Facilities

Another development scenario for nuclear in support of in situ oil sands projects is in the form of small scale nuclear energy facilities (NEFs), such as high temperature gas cooled reactors and liquid metal cooled reactors. Of all the options available, liquid metal cooled reactors such as the Toshiba 4S are considered ready for deployment before 2030. High temperature gas reactors, such as General Atomics and the Pebble Bed Modular Reactor (PBMR), could be ready for deployment by 2030. However, a lack of public information on the capital and operating costs for all the aforementioned, except Toshiba's 4S, prevents CERI from performing a detailed cost assessment.

The Toshiba 4S is a commercially available facility that could be deployed in the oil sands before a large NPP. It is designed to run continuously for 30 years without the need for refuelling. While the 4S would have to undertake the same regulatory process (up to 36 months), it could commence commercial operations just 1 year after receiving CNSC approval. Given the lack of knowledge in Canada on the 4S is it more than likely that it could take considerably longer to go through the regulatory process, unless assistance was provided to the CNSC by another nuclear regulatory agency that is familiar with the 4S. The quicker construction time is due to the NEFs size and method of construction (factory). According to information provided to CERI by Sandia National Laboratories (SNL), the 4S could be constructed in Japan and ready for deployment within a year from the start of construction. If the concrete padding and housing (located on-site in Alberta) for the NEF was constructed in parallel with the 4S in Japan, the facility could be in place in approximately one year.

The 4S is currently in the licensing phase with the U.S. Nuclear Regulatory Commission (US NRC) for a 108 GJ per hour facility, and a 450 GJ facility is being designed. Both reactors would be

[20] F. Roques, W. Nuttall, D. Newbery, and R. Neufville, "Nuclear Power: A Hedge Against Uncertain Gas and Carbon Prices", November 2006, CWPE 0555 and EPRG 09

considered "paper reactors" and are therefore subject to substantial capital and operator cost uncertainty.

Discussions with members of the oil sands industry and SNL indicate that the 4S can produce steam at sufficient temperature (500 degrees Celsius) and pressure (10 MPa) for an in situ oil sands operation, in addition to a mine. Electricity turbines can be added onto the facility, and are assumed in the capital costs presented below, where dollar values are considered nominal and reflect 2007.

Table 3.3
Assumptions

	Toshiba 4S
Base year (currency inputs)	2007
Starting year of construction	2011
First year of commercial operation	2012
Discount rate (rate of return) (%)	5
Corporate income taxes (%)	28.5
Annual Inflation Rate (%)	2.2
Net Capacity (GJ)	108
Project life (years)	30
Overnight capital (Million C$)*	30
Fixed O&M (C$/MWh net capacity)**	0.6
Variable O&M (C$/MWh net capacity)**	N/A
Fuel cost (Million C$)***	100
Annual capacity factor (%)	95

*The overnight capital is assumed to reflect a turnkey fixed price solution. This assumption is the same one used for the capital costs of an oil sands project. It should be noted that the capital cost for this reactor is likely several times higher than the assumed 30 million dollars. However, there is insufficient information available to make a reasonable assumption as to what this could be.

**O&M costs include operators and security personnel required. It is assumed that 8 operators and 34 security personnel are needed.

***The 4S is designed for an initial fuel load that should last for 30 years. Cost of fuel is estimated at $100 million dollars. This estimate is based upon public information and assumed fuel enrichment in the range of 17 to 19 percent. Costs for a 450 GJ are uncertain, since the fuel requirement is not known. No estimate is included for spent fuel management costs; since the fuel is sent back to Japan.

Using these as inputs into CERI's supply cost model, we have the following results:

Table 3.4
Discounted Nuclear Supply Cost at Facility

Supply Cost (Real Canadian dollars per GJ, 2007)	4S @ 108 GJ
Return on Investment	Included
Fixed Capital	2.1
Fuel	6.8
O&M	4.7
Income Taxes	5.4
Emissions Compliance Costs	0.0
Total Supply Cost	19.0

While the results indicate that the 4S could cost $19.0/GJ, further analysis is required to narrow down not only the output from the facility but updated capital, operating, and fuel costs. The 108 GJ 4S would not be able to support a 30,000 BPD SAGD project. Approximately 12 4S units would be required to provide sufficient energy for a project. The 4S is believed to be able to load follow and could be very responsive to changes in the thermal requirements by an in situ operator. However, the issue of a heat sink would need to be carefully examined for the 4S and any reactor being used for a thermal process.

It is possible to configure large NPPs, such as the previously mentioned ACR and EPR, for the co-production of steam and electricity. For the purpose of the analysis we assumed an all steam configuration (thus providing a lower bound for capital costs). It was assumed that 30 percent of the capital costs for a NPP are associated with the equipment and material for electricity generation (turbine and support buildings). With this assumption we can provide an estimate for 100 percent thermal output at 95 percent lifetime capacity. Operating, fuel, and fixed costs are assumed the same as used previously.[21]

[21] Dollar values are considered nominal and reflect 2007.

Table 3.5
Assumptions – Average Base-load Nuclear (Thermal)

	Average Base-load Nuclear
Base year (currency inputs)	2007
Starting year of construction	2011
First year of commercial operation	2014
Discount rate (rate of return) (%)	5
Corporate income taxes (%)	28.5
Annual Inflation Rate (%)	2.2
Net Capacity (GJ/h)	12,038
Project life (years)	60
Overnight capital (Million C$)*	3,922
Fixed O&M (C$/ MWh net capacity)	0.5
Variable O&M (C$/MWh net capacity)	7.0
Fuel cost (C$/MWh net capacity)	7.2
Annual capacity factor (%)	95

*The overnight capital is assumed to reflect a turnkey fixed price solution. This assumption is the same one used for the capital costs of an oil sands project.

Using the information contained above, we have inputted the data and assumptions into CERI's supply cost model. As is indicated below, large scale nuclear supply costs are below the supply cost range for the Toshiba 4S.

Table 3.6
Discounted Average Base-load Nuclear (Thermal) Supply Cost at Facility

Supply Cost (Real Canadian dollars, 2007 per GJ)	**Average Base-load Nuclear**
Return on Investment	Inc.
Fixed Capital	2.2
Fuel	2.2
O&M	2.4
Income Taxes	2.7
Emissions Compliance Costs	0.0
Total Supply Cost	9.4

3.2 Gasification and Synthesis Gas Production

Gasification has been in use for more than half a century and is a proven technology currently operating all over the world, including in Alberta at the Long Lake integrated in situ oil sands facility. Gasification involves heating a solid fuel material by partially combusting it with insufficient air for complete combustion. This process is known as "partial oxidation of organic material". In this process the majority of carbon (C) is converted into synthesis gas (syngas) by use of a gasification agent (air, oxygen, and steam).

Gasification is a process that does not burn the feedstock (coal/coke/asphaltene) but instead gasifies the feedstock (gasification). In this process the impurities in coal, like sulphur, nitrogen and many other trace elements, are almost entirely filtered out when coal is gasified.

Syngas is the name given to gases of varying compositions that are generated from the thermal conversion of a hydrocarbon, including natural gas, coal, oil, gases from waste-to-energy facilities including biomass, and municipal solid waste (MSW).

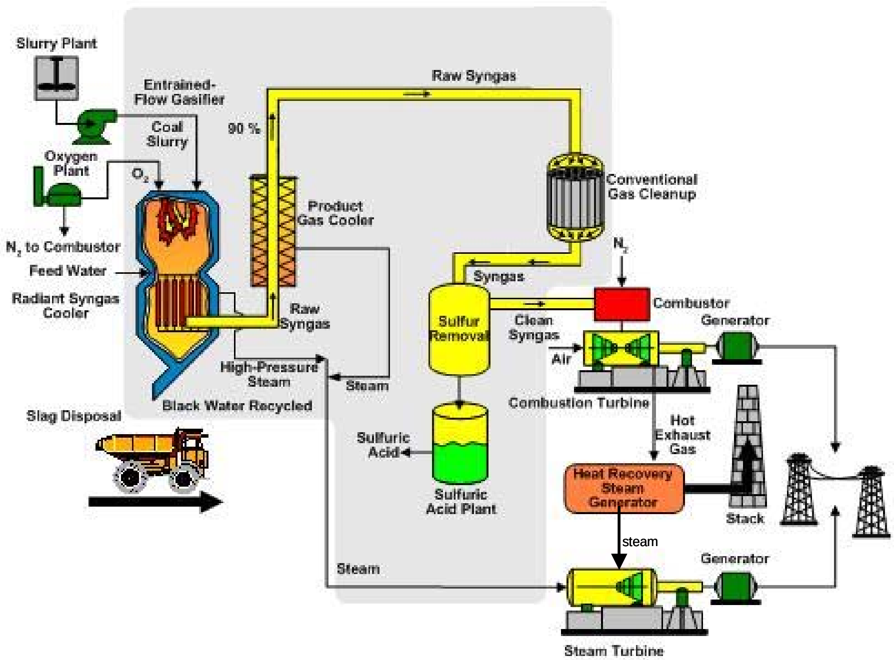
- Syngas is a mixture containing hydrogen (H_2) and carbon monoxide (CO) that can be used as a source of energy for internal combustion engines, or as a source of chemical building blocks in petrochemical plants.

Integrated Gasification Combined Cycle Technology (IGCC) combines both steam and gas turbines. Figure 3.5 shows a simple diagram of IGCC configuration.[22] The IGCC system consists of four main stages: feeding, gasifier reactor, gas cleaning, and utilization of combustible gas for steam and electricity generation.

It is important to point out that while gasification could produce a syngas that is less GHG intensive than the feedstock (coal/coke), the gasification process produces a substantial amount of GHG emissions when CCS is not implemented (it is anticipated that all gasification projects will be combined with CCS).

22 http://www.cogeneration.net/IntegratedGasificationCombinedCycle.htm

Figure 3.5
Integrated Gasification Power Plant Configuration



3.2.1 CERI Gasification Design Assumptions

For the purpose of the study we have decided to rely upon information provided by the U.S. Department of Energy (DOE), National Technology Laboratory.[23] The oil sands by-product petroleum coke could be easily swapped into the gasifier in place of coal with limited impact on costs. Asphaltenes could also be used in the gasifier, however, we could not conclude whether the use of asphaltenes would result in substantial changes in the capital or operating costs of the facility. This is one reason why asphaltenes have not been examined in this study. Another reason was a general lack of public information on the capital and operating costs for an asphaltene gasification system.

Several "Reference Plants" were developed. The key assumptions behind these facilities are presented in Table 3.7 and 3.8, where dollar values are considered nominal and reflect 2007.

[23] US Department of Energy, National Technology Laboratory "Industrial Size Gasification for Syngas, Substitute Natural Gas and Power Production", DOE/NETL-401/040607, April 2007

Table 3.7
Gasification Production Assumptions

		SynGas	SynGas with Hydrogen	Substitute Natural Gas (SNG)	Syngas to Power	SNG to Power (Cogen)
Total Syngas Flow	lb/hr	158700	132540	34469	n/a	6905
Net Syngas Product for Export,	lb/hr	151400	132037	34469	n/a	159
Syngas Product Energy,	MMBtu/hr	952	769	791	n/a	n/a
Hydrogen Production	lb/hr	n/a	3019	n/a	n/a	n/a
Hydrogen Energy	MMBtu/hr	n/a	184	n/a	n/a	n/a
CTCC Power Production	kWe	n/a	n/a	n/a	133500	88700

Table 3.8
Gasification Financial Assumptions

	SynGas	SynGas with Hydrogen	Substitute Natural Gas (SNG)	Syngas to Power	SNG to Power (Cogen)
Base year (currency inputs)	2007	2007	2007	2007	2007
Starting year of construction	2011	2011	2011	2011	2011
First year of commercial operation	2013	2013	2013	2013	2013
Discount rate (rate of return) (%)	5.0	5.0	5.0	5.0	5.0
Corporate income taxes (%)	28.5	28.5	28.5	28.5	28.5
Annual Inflation Rate (%)	2.2	2.2	2.2	2.2	2.2
Feedstock (Tonne/day of coal)[24]	1038.6	1038.6	1038.6	1038.6	1038.6
Net Output (GJ/day)	24,115.2	19,504.8	20,035.2	n/a	4,024.8
Net Output (MWh)	n/a	n/a	n/a	133.5	88.7
Project life (years)	20	20	20	20	20
Overnight capital (Million 2007 C$)*	146.0	153.27	180.9	249.21	264.9
Fixed O&M (Million 2007 C$/year)	7.7	7.7	8.0	8	10.7
Variable O&M (Million 2007 C$/year)	15.8	16.0	17.9	17.9	4.0
Fuel cost (Million 2007 C$)**	16.9	16.9	16.9	16.9	16.4
Annual capacity factor (%)	95.0	95.0	95.0	95.0	95.0
Emissions Compliance Cost (real C$ / tonne CO2e)	15.0	15.0	15.0	15.0	15.0

*The overnight capital is assumed to reflect a turnkey fixed price solution. This assumption is the same one used for the capital costs of an oil sands project. The overnight capital costs include a coal receiving, storage and handling as well as limestone storage and handling systems. For each case additional capital costs are incurred for the gas clean-up process. For example, the SNG case includes the addition of a water-gas shift reaction system and methanation process to remove most of the hydrogen from the gas stream to produce a syngas that can meet pipeline quality specifications. Sulphur is produced as a by-product and the capital costs include the cost to recover the by-product, however, no assumptions are made as to the value of the by-product or the cost to manage the sulphur.

**Fuel costs reflect purchased coal at US$ 17.75/tonne, escalated to 2007 Canadian dollars.

[24] While it is possible to swap coal for coke in this gasifier, a detailed analysis would be required to determine the exact quantity of coke required on a btu basis. On an MMbtu basis 26,832 MMBTU are required daily to produce the required synthetic gas listed as the net output.

Using these as inputs into CERI's supply cost model, an energy output price has been calculated. For the co-production of hydrogen, all outputs have been priced on a common $/GJ basis. For example, 184 MMBtu/h of hydrogen produced using syngas in an integrated coal gasification facility will cost C$16.0/GJ, the same cost applies to the 769 MMBtu/h of syngas. The following are the results for gasification with coal:

Table 3.9
Discounted Gasification of Coal Supply Cost at Facility

Supply Cost (Real Canadian dollars per GJ, 2007)	SynGas	SynGas with Hydrogen	Substitute Natural Gas (SNG)
Return on Investment	Included	Included	Included
Fixed Capital	1.4	1.8	2.1
Fuel	2.8	3.4	3.3
O&M	3.8	4.8	5.1
Income Taxes	3.7	4.5	4.7
Emissions Compliance Costs	1.5	1.4	1.4
Total Supply Cost	13.2	16.0	16.6

If we were to assume that petroleum coke is used as the dominant fuel source, then the cost of fuel would be reduced. For our purposes, we have assumed the fuel cost is zero and there are no transportation costs to deliver the fuel from the source to the gasification site.[25]

Table 3.10
Discounted Gasification of Petroleum Coke Supply Cost at Facility

Supply Cost (Real Canadian dollars per GJ, 2007)	SynGas	SynGas with Hydrogen	Substitute Natural Gas (SNG)
Return on Investment	Included	Included	Included
Fixed Capital	1.4	1.9	2.1
Fuel	0.0	0.0	0.0
O&M	3.8	4.8	5.1
Income Taxes	2.6	3.2	3.4
Emissions Compliance Costs	1.5	1.4	1.4
Total Supply Cost	9.4	11.3	12.0

At first glance, a single product gasification facility producing a syngas yields a lower cost product than the alternative SNG. In a world without any carbon constraints, an oil sands operator would be in a better position if they relied upon syngas, when compared to the more expensive SNG. Unfortunately, we are moving towards a carbon constrained world where the composition of the stream is relevant to an oil sands operator.

[25] Since we have made no assumptions pertaining to the location of the gasification facility, this is a reasonable assumption to make.

Table 3.11
Syngas and SNG Composition

Syngas Composition Element	SynGas % mol weight	SynGas with Hydrogen Removed % mol weight	Substitute Natural Gas (SNG) % mol weight
Ar	114.0	42.0	0.4
BTX	11.0	11.0	9.4
CH4 (Methane)	**7,003.0**	**6,730.0**	**32,479.1**
C2H4	97.0	55.0	54.8
C2H6 (Ethane)	**514.0**	**297.0**	**296.1**
C3H6	56.0	8.0	8.3
C3H8 (Propane)	307.0	168.0	165.2
C4H8	50.0	1.0	0.5
C4H10	138.0	11.0	10.0
CH3OH	0.0	0.0	0.0
CO	**112,795.0**	**114,781.0**	**21.3**
CO2	**14,069.0**	**415.0**	**38.1**
COS	1.3	0.0	0.0
HCN	0.0	0.0	0.0
HCL	0.0	0.0	0.0
H2	**4,431.0**	**1,615.0**	**62.5**
H2S	**0.7**	**0.0**	**0.0**
MIBK	0.0	1.0	0.0
N2	**11,814.0**	**7,901.0**	**1,324.2**
NH3	0.0	0.0	0.0
O2	**0.0**	**0.0**	**0.0**
PHENOL	0.0	0.0	0.0
SO2	0.0	0.0	0.0
Total	151,401.0	132,036.0	34,469.8
CO2e (kg/GJ/hr)	96.08	111.42	48.09

For the production of electricity, from gasified coal:

Table 3.12
Discounted Gasification of Coal Electricity Supply Cost at Facility

Supply Cost (Real Canadian dollars per MWh, 2007)	Syngas to Power	SNG to Power (Cogen)
Return on Investment	Included	Included
Fixed Capital	18.4	29.5
Fuel	20.7	30.2
O&M	31.8	27.1
Income Taxes	33.2	37.0
Emissions Compliance Costs	13.5	6.7
Total Supply Cost	117.6	130.6

For the production of electricity, from gasified coke:

Table 3.13
Discounted Gasification of Coke Electricity Supply Cost at Facility

Supply Cost (Real Canadian dollars per MWh, 2007)	Syngas to Power	SNG to Power (Cogen)
Return on Investment	Included	Included
Fixed Capital	19.1	29.5
Fuel	0.0	0.0
O&M	33.0	27.1
Income Taxes	27.2	25
Emissions Compliance Costs	14.0	6.7
Total Supply Cost	93.2	88.3

At over C$80/MWh, a cogeneration of syngas to power facility is more expensive than the nuclear alternative previously explored. This may be a limiting factor in the adoption of IGCC. However, the political and regulatory challenges, in addition to the long lead time for nuclear will likely result in increased use of gasification facility and possibly a corresponding reduction in costs as the implementation of the technology takes hold.

In order for gasification to take hold in Alberta there will be a need to stimulate the development of an extensive CCS pipeline network to support the sequestration of emissions.

3.3 Alberta Emissions Plans

In November 2002, the province of Alberta became the first Canadian province to introduce a regulatory framework for industrial GHG emissions. Rather than adopting absolute reductions in GHGs, the province has chosen to limit the amount of GHG emissions per unit of output, or GHG intensity. Under the Climate Change and Emissions Management Act (CCEMA), large GHG emitters,[26] which are responsible for about 70 percent of Alberta's total GHG output,[27] are required to decrease their emissions intensity by 12 percent annually, relative to an emissions baseline. The emissions baseline was determined using Alberta Environment data collected between 2003 and 2005.

The Climate Change Action Plan introduced in January 2008 calls for a GHG emissions target of 14 percent below 2005 levels, or 50 percent below the projected business-as-usual emissions level in 2050. The majority of the emissions reductions will come from activities in the oil sands. The Plan's strategy focuses on new and next generation CCS technologies, which are anticipated to provide approximately 70 percent of the 200 Mt reduction target. Other GHG emissions reductions will be derived from a combination of consumer incentive programs (30 percent) and cleaner energy production (18 percent). Funds for the development of CCS technologies will come from the Government of Alberta, the Government of Canada (ecoTrust), and the Climate Change and Emissions Management Fund. Alberta has established a CCS Council, consisting of government and industry members, for the purpose of addressing regulatory issues relating to CCS. The final report of the CCS Council will be issued by the end of 2008.

Two complementary Alberta initiatives, the Alberta Saline Aquifer Project (ASAP)[28] and the Integrated CO_2 Network (ICO_2N),[29] are advancing the development of large-scale commercial CCS.

ICO_2N is working with the Alberta Government and the Government of Canada to develop a national CCS system. Ultimately, the CCS system will involve the capture of CO_2 from multiple large industrial sources, a pipeline system to transport the CO_2, and injection facilities at enhanced oil recovery sites or long-term storage sites.

3.4 Carbon Capture and Storage (CCS)

Carbon capture is the process of capturing CO_2 from gas streams which are usually emitted by large industrial sources. Subsequently, captured CO_2 is compressed and transported for injection into geologic storage or other reservoirs for the purpose of long-term storage and management. Combined, this formed the process often called Carbon Capture and Storage (CCS). In this

[26] The Government of Alberta defines large emitters as those facilities that produce more than 100,000 tonnes of GHG per year.

[27] Alberta Environment, 2007.

[28] Participants in ASAP include ATCO Power Canada Ltd., BP Canada Energy Company, Chevron Canada Resources, ConocoPhillips, Enbridge Inc. EnCana, EPCOR, GreatPoint Energy Inc., Hatch Energy, Laricina Energy Ltd., Norwest Corporation, OPTI Canada Inc., Pembina Pipeline Corporation, Penn West Energy Trust, Praxair Canada Inc. Quadrise Canada Corporation, Schlumberger Carbon Services, TransCanada, UTS Energy Corporation

[29] Participants in ICO_2N include Agrium Inc., Air Products Canada, Inc., Canadian Natural Resources Ltd., ConocoPhillips Company, EPCOR, Husky Energy Inc., Imperial Oil Ltd., Keyera, Nexen Inc., Shell Canada Ltd., Sherritt International Corporation, Suncor Energy Inc., Syncrude Canada Ltd., Total E&P Canada Ltd., TransAlta Corporation.

process, the objective of CO_2 reduction is achieved. While some pilot projects are present in Canada and abroad, CCS technologies are primarily in the developmental stage.

Medium Term Outlook (2007-2020)

According to ICO_2N, there is the potential for almost 25 Mt/year of carbon dioxide from industrial sources in Alberta by 2020 that could be sequestered using a pipeline network, that could be place by then.[30] This is consistent with NRCan's belief (as reported by ICO_2N) that there might be 10 Mt CO_2/year of pipeline supplied CCS in the WCSB by 2015, with total Canadian storage potentially exceeding 40 Mt CO_2/year by 2030. This is under the assumption that storage starts taking place in other sedimentary basins, and that sufficient pipeline capacity is in place.

Estimated Costs

According to the ICO_2N and one of their cited sources, the 2006 NRCan CCS Technology Roadmap, costs for CCS activities can be divided into three components: Capture (including compression), transportation, and storage. For the purpose of our study, we are focusing on activities "inside the fence" for an oil sands operator. The costs and issues with transportation and storage will not be considered. Estimated capture costs used in this report reflect preliminary work by NRCAN and others. ***CERI believes that these estimates are far lower than actual costs for CCS when it is implemented, and they should be taken as such***.

The estimated cost for post-combustion capture – as would be experienced at oil sands projects – is in the range of \$50 to \$70/tonne, with a representative value of \$55/tonne. The representative value can be viewed as the point at which it makes sense to start capturing emissions from an oil sands project or other industrial facility. For any emissions compliance cost below this value, it makes more economic sense for projects to pay the compliance cost and emit.

Pre-combustion costs of \$20 to \$50/tonne reflect the costs that would induce a large scale gasification facility to capture their emissions stream and separate out the CO_2 for storage or injection into oil fields for Enhanced Oil Recovery (EOR). The representative value of \$27.50/tonne can be used to reflect the point at which a gasification project would capture their emissions. While an updated assessment is unavailable, it is our opinion that gasification costs of \$65.00/tonne would be sufficient to induce large scale gasification of coal or coke in Alberta. This implies that a slightly higher cost is required for post-combustion capture. Due to the lack of public information to support these statements, we are relying upon the \$27.50 and \$55/tonne values with the caveat for the reader that these values are lower than we anticipate.

These representative values can be viewed as the minimum compliance cost to commence emissions reduction measures. While further research is required, it is beyond the scope of this report. Transportation costs are estimated at \$6/tonne for a 650 km pipeline, roughly the

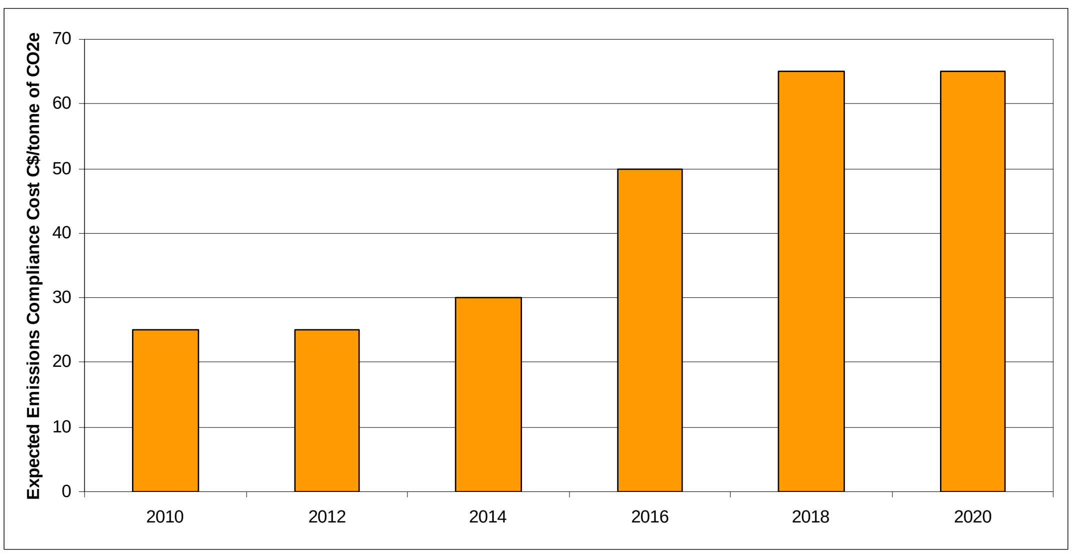
[30] *Assessment of GHG Emission Reduction Alternatives in the Canadian Context*, The Delphi Group, December 4, 2007.

distance from an oil sands mining project to potential reservoirs in central Alberta. Given the high cost environment that currently exists in Alberta, the representative values should be viewed as conservative in nature and subject to revisions.

3.5 Reference Case Emission Compliance Cost Projection

Given the extensive discussions taking place in Alberta and around the world, the environmental status quo is not likely to prevail over the coming decades. In an attempt to illustrate the impact that various emissions compliance costs could have on oil sands operators and on each alternative technology, we are elaborating upon the emissions compliance cost framework discussed by Environment Canada in their "Turning the Corner: Taking Action to Fight Climate Change" technical briefings, March 14, 2008. In Figure 3.6 we have reproduced Environment Canada's projection for the expected marginal emissions price, based upon a cap-and-trade market system, which is C$65/tonne by 2018. As was assumed with the $15/tonne value, the expected marginal emissions price is assumed to be a real dollar amount in each period.

Figure 3.6
Reference Case Emissions Compliance Cost Projection



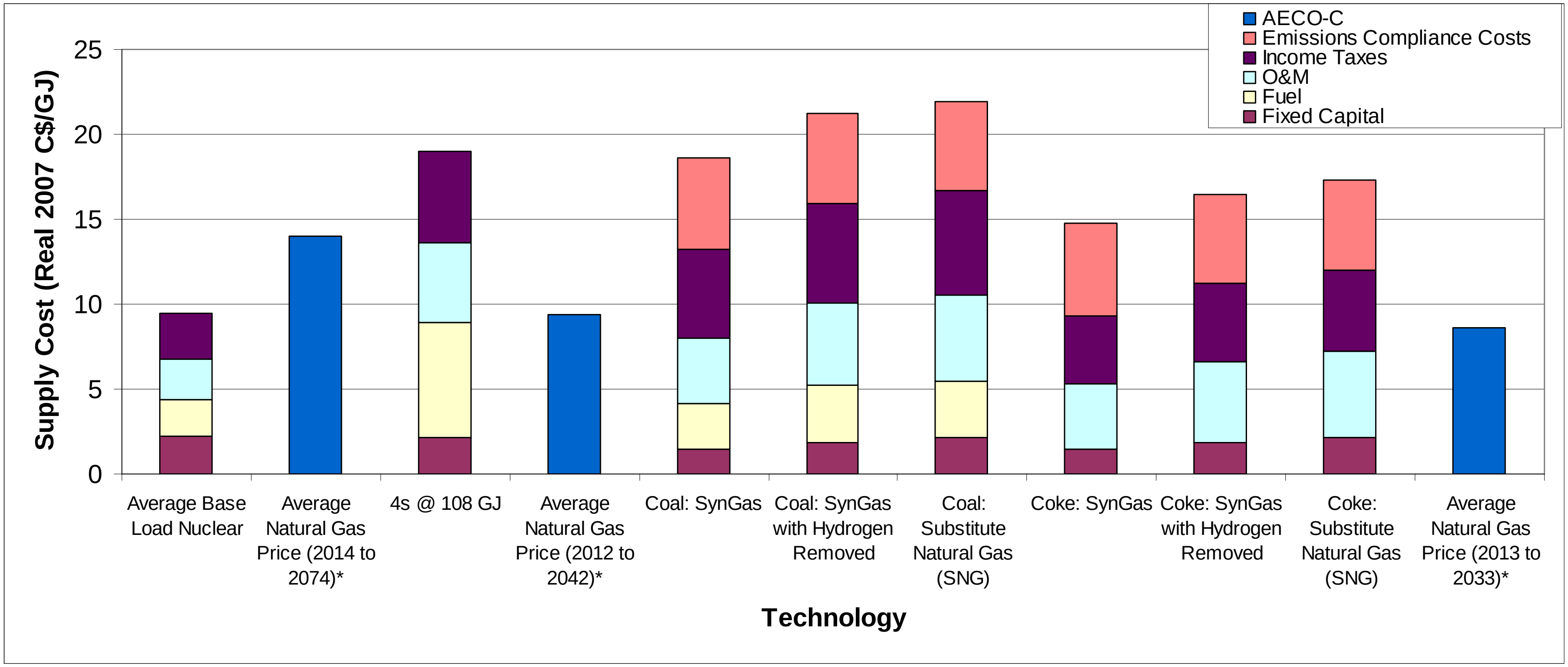
Between each year listed above, we have assumed the compliance cost is constant. In other words, after 2020 the compliance cost is $65/tonne for each future year. Compliance costs will not come into play for CO_2e emissions under 100,000 tonnes/year – the Alberta framework.

Without CCS, and assuming each alternative pays to emit, their costs (which summary the Reference Case values) are as follows:

Table 3.14
Reference Case Alternative Fuel (Thermal) Supply Costs

Supply Cost (Real Canadian dollars, 2007 per GJ)	Average Base-load Nuclear	4S @ 108 GJ	Coal: SynGas	Coal: SynGas with Hydrogen Removed	Coal: Substitute Natural Gas (SNG)	Coke: SynGas	Coke: SynGas with Hydrogen Removed	Coke: Substitute Natural Gas (SNG)
Return on Investment	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.
Fixed Capital	2.2	2.1	1.4	1.9	2.1	1.4	1.9	2.1
Fuel	2.2	6.8	2.8	3.4	3.3	0.0	0.0	0.0
O&M	2.4	4.7	3.8	4.8	5.1	3.8	4.8	5.1
Income Taxes	2.7	5.4	5.2	5.9	6.1	4.1	4.6	4.8
Emissions Compliance Costs	0.0	0.0	5.5	5.3	5.3	5.5	5.3	5.3
Total Supply Cost	9.4	19.0	18.6	21.2	22.0	14.8	16.5	17.3

Figure 3.7
Supply Costs of Alternative Technologies & Average Price of Natural Gas (Reference Case Projection)



3.6 Deployment of CCS

CCS is likely to be deployed for gasification and oil sands projects using the Reference Case Projection of compliance costs. Based upon the compliance costs in the Reference Case we are developing a scenario where CCS is deployed. The deployment of CCS for gasification projects would start at $27.50/tonne in 2014. This also reflects estimates from industry when larger gasification projects could come online in Alberta, being CCS ready.

Using the Reference Case for Compliance Costs as a guide, CCS from oil sands facilities could commence by 2018. Prior to this period, oil sands operators should pay the compliance costs, which are below the cost of CCS.

The fuel cost for each alternative, taking into account pre-combustion compliance costs is presented in the tables below. They do not take into account costs to transport carbon and long-term storage and monitoring costs.

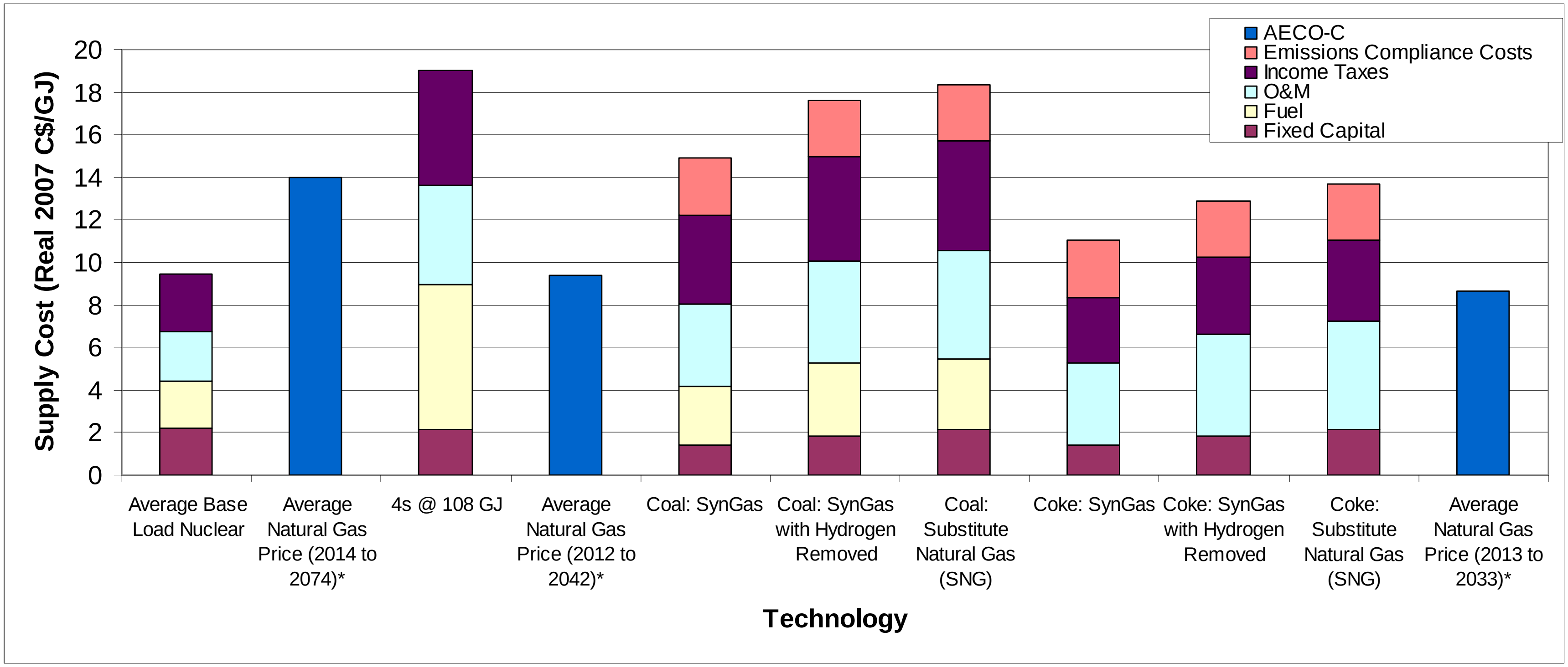
Table 3.16
Capture Cost Projection Alternative Fuel (Thermal) Supply Costs

Supply Cost (Real Canadian dollars, 2007 per GJ)	Average Base-load Nuclear	4S @ 108 GJ	Coal: SynGas	Coal: SynGas with Hydrogen Removed	Coal: Substitute Natural Gas (SNG)	Coke: SynGas	Coke: SynGas with Hydrogen Removed	Coke: Substitute Natural Gas (SNG)
Return on Investment	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.
Fixed Capital	2.2	2.1	1.4	1.9	2.1	1.4	1.9	2.1
Fuel	2.2	6.8	2.8	3.4	3.3	0.0	0.0	0.0
O&M	2.4	4.7	3.8	4.8	5.1	3.8	4.8	5.1
Income Taxes	2.7	5.4	4.2	5.0	5.2	3.1	3.6	3.8
Emissions Compliance Costs	0.0	0.0	2.7	2.6	2.6	2.7	2.6	2.6
Total Supply Cost	9.4	19.0	14.9	17.6	18.3	11.1	12.9	13.7

Table 3.17
Capture Cost Projection Alternative Fuel (Electric) Supply Costs

Supply Cost (Real Canadian dollars, 2007 per MWh)	Average Base-load Nuclear	Coal: Syngas to Power	Coal: SNG to Power (Cogen)	Coke: Syngas to Power	Coke: SNG to Power (Cogen)
Return on Investment	Included	Included	Included	Included	Included
Fixed Capital	18.7	18.4	29.5	17.2	29.5
Fuel	14.3	20.7	30.2	0.0	0.0
O&M	14.8	31.8	27.1	29.6	27.1
Income Taxes	19.1	37.1	39.0	24.4	27.0
Emissions Compliance Costs	0.0	24.5	12.2	22.8	12.2
Total Supply Cost	66.9	132.6	138.1	94.0	95.8

Figure 3.8
Supply Costs of Alternative Technologies & Average Price of Natural Gas (Capture Cost Projection)



While nuclear energy still remains the most economic option for the production of energy, gasification units may be an economically viable option, once the cost to refurbish a unit and extend its life is better understood and added to the economic analysis.

With CCS, coke gasification still remains an expensive option, based upon our assumptions for the gasification facilities and the average price of natural gas over the 20 year operating life for the gasification facilities.

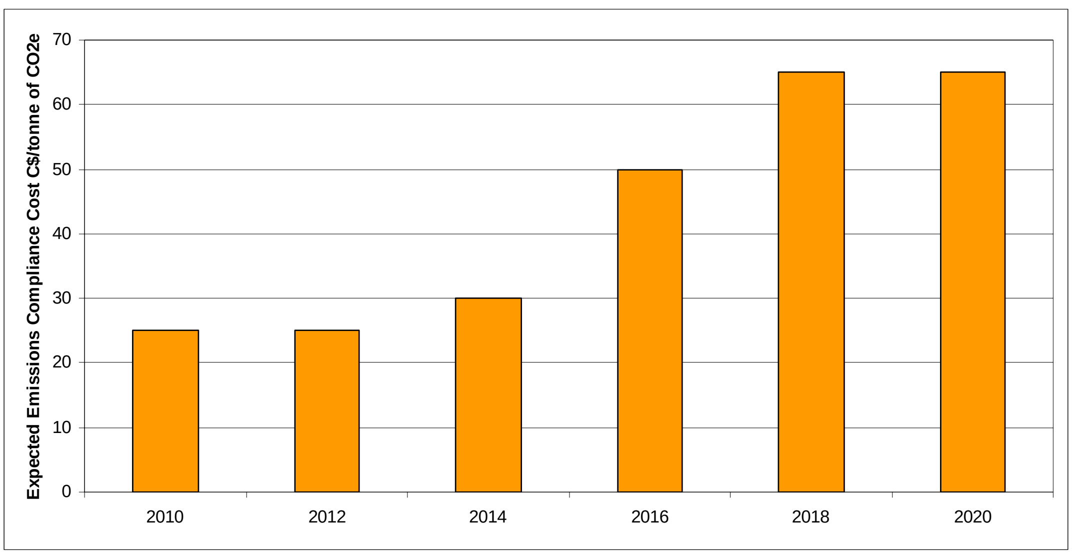
(THIS PAGE INTENTIONALLY LEFT BLANK)

CHAPTER 4
MOVING TOWARDS LOW EMISSIONS "GREEN BITUMEN"

Moving towards a world in which the oil sands is not viewed as dirty (from an emissions perspective) will require the reduction of GHGs such that the oil sands are on par with conventional oil. This is the scenario that reflects "***Green Bitumen***" where the emissions from the fuel used by an oil sands project are as low as possible. Emissions (carbon) compliance programs are being considered as a method to help spur the development of Green Bitumen. Often these programs are under the guise of some form of a "carbon market", where a cost is developed and applied to emitters.

Markets factors and/or government policy should push the carbon market into a position where the Reference Case develops until the cost of paying for emitting carbon exceeds the cost of storing. Given the current cost uncertainty in Alberta and the lack of an extensive CCS network being deployed, we will assume that the Reference Case (with a higher compliance cost) comes to fruition and the market prices by 2018 reflect the price to deploy CCS without significant government incentives.

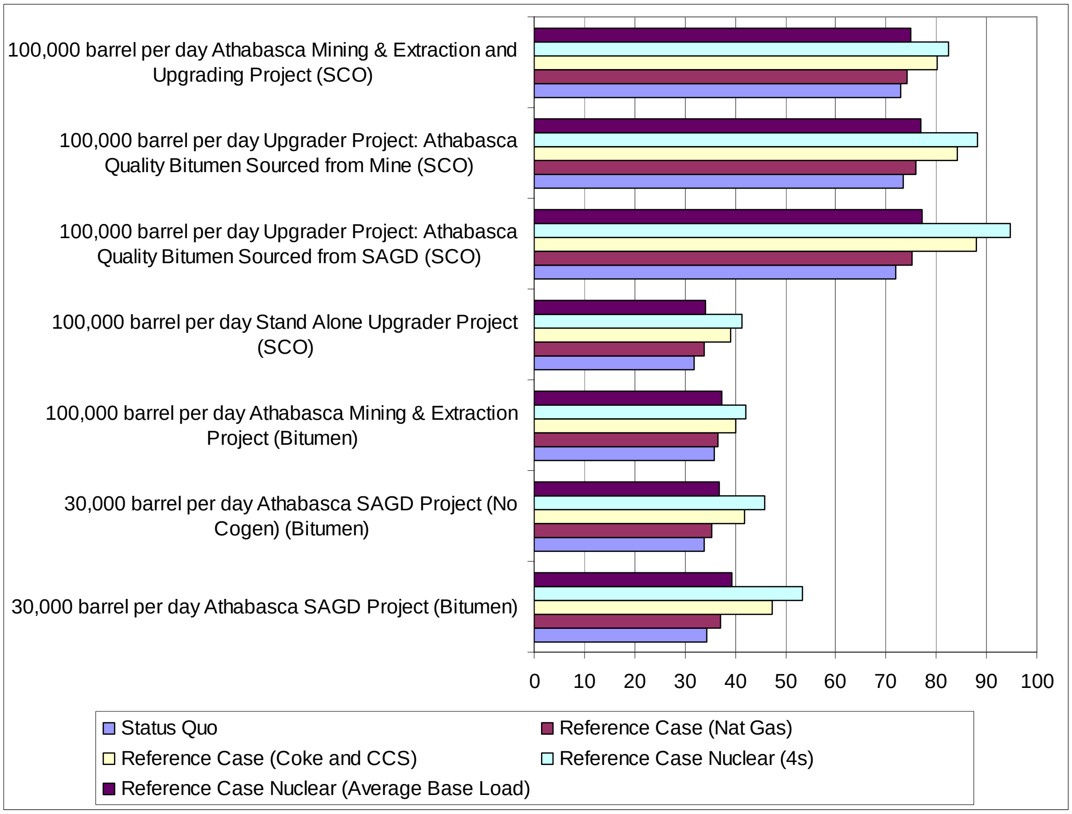
Figure 4.1
Reference Case Emissions Compliance Cost Projection



Using this as a starting point, we will examine several alternatives and how they impact the supply cost of bitumen.

Figure 4.2 summarizes the supply costs for oil sands projects when they adopt the various alternative technologies, relative to the status quo. The stand alone mines and SAGD should be considered as a supply cost on a per barrel of bitumen basis, while the others are per barrel of SCO.

Figure 4.2
Summary of Supply Costs $/bbl of Bitumen and SCO (where applicable)



It should be no surprise that the most economical option is under the status quo. As additional costs are imposed on an operator, the costs will be passed through the total supply cost of the product.

Producing a barrel of green bitumen necessitates the examination of the emissions from the various alternatives on a per barrel basis. The methodology used to produce the results in Table 4.1 is consistent with other sections of the study. The emissions being considered are point source and could be captured. While the table shows nuclear with 0.00 emissions on a per barrel basis, it is closer to 0.0020 per barrel since natural gas is being used for the first two and four years (4S and average base-load cases).

Table 4.1 shows the direct point source emissions from the oil sands Reference Case relative to conventional light oil and *does not reflect a life cycle assessment*.

- SAGD production without cogeneration produces 1.3 times the level of emissions from conventional oil;
- An integrated mining and upgrading project produces 0.6 times the level of emissions; based upon current oil sands projects, this can be as high as 2.6 times the level of emissions.[31]
- With carbon capture and storage and/or nuclear energy, the oil sands produce fewer emissions on a per barrel basis than conventional crude oil in Canada.

[31] Please refer to the Environment Canada Facility GHG Reporting information. http://www.ec.gc.ca/pdb/ghg/facility_e.cfm, November 2008.

Table 4.1
Average Annual Point Source GHGs Over the Life of a Project with Alternative Fuels (Kg/bbl of output)

	Status Quo	Reference Case (Nat Gas)	Reference Case (Coke and CCS)	Reference Case Nuclear (4S)	Reference Case Nuclear (Average Base-load)	Emissions Relative to Conventional
Conventional Light Oil[32]	42.00	42.00	N/A	N/A	N/A	
30,000 barrel per day Athabasca SAGD Project	82.71	82.71	21.69	0.00	0.00	2.0
30,000 barrel per day Athabasca SAGD Project (No Cogen)	54.99	54.99	13.49	0.00	0.00	1.3
100,000 barrel per day Athabasca Mining & Extraction Project	26.09	26.09	6.14	0.00	0.00	0.6
100,000 barrel per day Stand Alone Upgrader Project	39.17	39.17	8.90	0.00	0.00	0.9
100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from SAGD	124.53	124.53	22.39	0.00	0.00	3.0
100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from Mine	65.25	65.25	15.04	0.00	0.00	1.6

[32] GHGenius, http://www.ghgenius.ca/reports/2007CrudeOilUpdateReport.pdf

Using the information from Table 4.1 coupled with our assumptions pertaining to when certain technologies could be deployed, we have constructed a scenario to examine the impact that deploying each alternative could have on the total emissions from the oil sands industry. While we do not take into account government support for projects, given the potential timeline for various emissions compliance scenarios, government support for a carbon capture network and storage facilities may be crucial to its success.

The study contains a detailed discussion of the process and assumptions used to develop the following section that will take us out of the realm of economic analysis and into a scenario where government intervention has made gasification a viable competitor to nuclear energy (neither superior nor inferior).

Building off of Alberta's Climate Change Plan, we will develop a scenario that achieves an emissions reduction such that the oil sands emissions are 14 percent below the 2005 level, or 18 million tonnes of CO_2e by 2050. Since our projection goes to 2030, we are looking to have a viable trend beyond 2030 to reach 18 MT by 2050.

Our scenario, which we refer to as the Emissions Reduction Scenario, starts will the deployment of a single gasification facility in 2013, which is followed by the deployment of two additional facilities in 2014. In 2016, a pilot project for small nuclear is assumed to be launched. The output from this facility is assumed to displace a mere 2 MMcf/d of natural gas demands.

A period of rapid expansion of gasification and nuclear starts in 2017 with a two unit gasification project coming online, followed by an additional two unit facility in 2018. By 2018, it is assumed that a nuclear facility will be operational (given the 4 to 6 year timeframe for licensing and construction we believe this is a reasonable timeframe). The facility is built as a "twin" design where two reactors equal the output of our average base-load facility,[33] with the second reactor coming online in 2019.

After the first small nuclear energy facility has undergone several years of testing (while having additional applications underway), we assume the facilities expand in batches of six units. Since Toshiba indicates that the 4S would be constructed in a factory setting with 10 units a piece (taking a year), this is a reasonable assumption. A 12 unit facility closely matches the energy requirements of an in situ project. In 2020, a six unit facility comes on-line followed by a second six unit facility in 2021.

By 2021, we believe that gasification technology and the learning curve in Alberta will have improved to the point that gasification plants can come online as four-train units (or four individual units). In 2020 and 2021, we assume that a four-train unit comes on-line each year. Additional four-train units come on-line in 2025, 2026, 2029 and 2030. This brings the total

[33] Since our analysis took into account the costs for a Twin ACR-1000 we believe this is a reasonable assumption.

number of 834 GJ/d (or 19 MMcf/d) facilities to 31 with a total demand, coal equivalent of, 32,196 tonnes per day.

We assume that small scale nuclear facilities continue to be deployed over the scenario, with two additional six unit facilities in 2024 and 2025, bringing the total number of units to 25 in the province by 2025. In the 2028 and 2029 period, additional base-load nuclear facilities are assumed to come on-line, bringing the total number of units to 4.

The expansion of these facilities is shown in Table 4.2, which includes the total natural gas purchases and how they are affected by the new technologies. By 2030, natural gas purchases could drop by over 1.7 bcf/d relative to the Reference Case shown in Chapter 2. We have made no assumptions as to reliability and the requirement for backup equipment to support any new technology. For example, a nuclear facility would require non-nuclear back-up for times when the facility is off-line for repairs. The backup could be nuclear or another energy source. Depending upon the assumptions being made this could have an impact on the emissions. For our purpose, we have implicitly assumed the backup is the technology being used (i.e., nuclear is the backup for nuclear).

Table 4.2
New Technology Implementation and Impact on Natural Gas Purchases

	Gasification MMcf/d	Nuclear Base MMcf/d	Nuclear 4S MMcf/d	Reference Case Gas Purchases MMcf/d	Emissions Reduction Scenario Purchased Gas MMcf/d
2013	-19	0	0	3,141	3,122
2014	-57	0	0	3,482	3,425
2015	-57	0	0	3,680	3,623
2016	-57	0	-2	4,139	4,079
2017	-95	0	-2	4,497	4,399
2018	-134	-138	-2	4,767	4,493
2019	-134	-275	-2	4,730	4,319
2020	-134	-275	-17	5,099	4,673
2021	-210	-275	-17	5,475	4,973
2022	-286	-275	-17	5,604	5,025
2023	-286	-275	-17	5,695	4,841
2024	-286	-275	-32	5,814	4,945
2025	-363	-275	-47	5,967	5,008
2026	-439	-275	-47	5,933	4,897
2027	-439	-275	-47	5,841	4,805
2028	-439	-413	-47	5,735	4,424
2029	-515	-550	-47	5,671	4,008
2030	-592	-550	-47	5,659	3,920

We have used this information to develop an emissions projection, which takes into account the reduced GHGs from SNG (assume CCS takes places at the gasification facility) or 48.09 kg/GJ. Even with the extensive expansion of gasification that is assumed, the overall impact on GHGs is minimal. Nuclear energy plays an important role in reducing emissions, but its role is overshadowed by the potential that carbon capture could play in emissions reduction. Using information from the ICO_2N, we have assumed that a carbon pipeline network is deployed in the oil sands region to support the capture and transportation – for storage – of carbon emissions. The network is assumed to transport up to 15 Mt/year of CO_2 by 2026, starting with 2 Mt/year in 2018, 4 Mt/year by 2019, 5 Mt/year by 2021, 10 Mt/year by 2023 and 15 Mt/year by 2026. This amounts to around 60 percent of the potential carbon that could be captured and transported in the province by 2029. Since bitumen production from the oil sands is one of the largest GHG emitters, this is a reasonable assumption to make, since ICO_2N indicates that their assumed 25 Mt of transportation excludes coal fired power plants.[34]

By 2030, it is assumed that storage increases to the levels indicated by ICO_2N of 40 Mt/year. Under this scenario, emissions are further reduced by capturing a total of 24 Mt/year of CO_2.

Our analysis is shown below in Figure 4.3. Emissions are reduced to 41 Mt by 2030, compared to 132 Mt by 2030 under the Reference Case. This is a reduction of 69 percent over a 17 year period. The emissions reduced through SNG are minor, and reflect the small difference in CO_2e emissions from a GJ of SNG relative to natural gas. One of the critical areas over the coming decades will be the deployment of an extensive CCS network. The network is critical to ensure sufficient gas and electricity supply (through the adoption of clean SNG where the carbon emissions from the gasification process are captured). Furthermore, the adoption of a network that is fed (partially) by point source oil sands emissions can be an important and crucial contributor in the battle against increasing emissions. Without nuclear energy coming into the mix, emissions from the oil sands (and upgrading) could be over 60 Mt/year by 2030. Adopting nuclear energy, while potentially controversial, is an important contribution. While we have not included any sensitivity for emissions reductions through technology adoption and efficiency improvements, we believe it could amount to a significant portion of non-captured emissions reductions. The amount could equal or rival that from nuclear energy; however, there is no silver bullet technology solution and the adoption of a mixture of technologies will likely be the approach used by industry and government. Other options that have not been considered, yet could be significant for emissions reduction would include reduced energy use for, amongst other options, compressors, tailing pond equipment, lower steam oil ratios (beyond our assumed 3:1 for steam to oil for SAGD projects) and reduced water temperatures for mining projects.

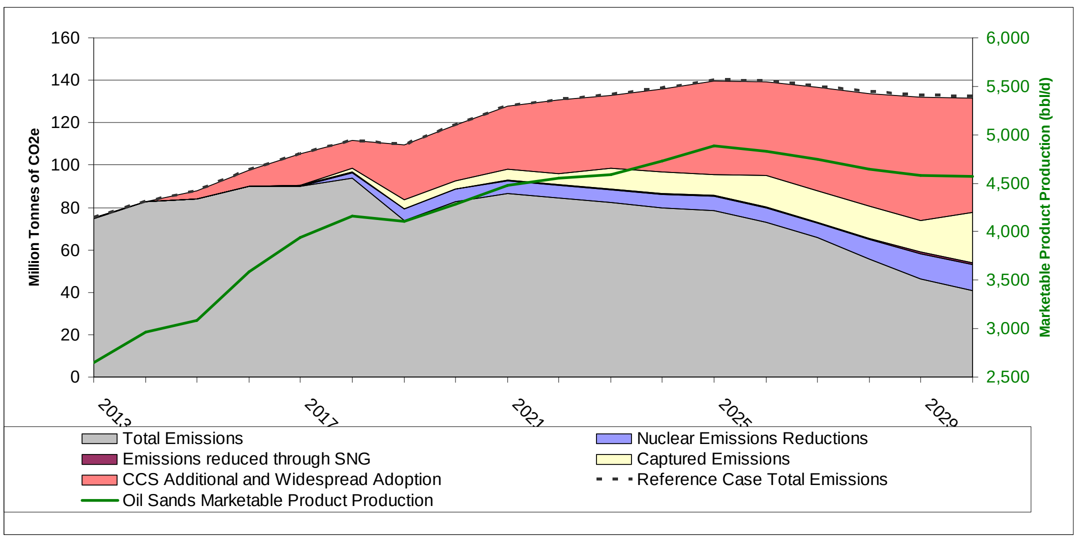
The government of Alberta has a strong commitment towards the adoption of CCS to reduce emissions. Building off the work of ICO_2N, the government has indicated policy and monetary support towards a reduction of emissions by 50 million tonnes in 2020, rising to 200 million

[34] The Delphi Group, for ICO2N, "Assessment of GHG Emission Reduction Alternatives in the Canadian Context", December 4, 2007.

tonnes by 2050.[35] Using our assumption from earlier we have provided an additional scenario where 60 percent of the plans reductions are used by the oil sands. In other words, an additional 6 million tonnes in reductions by 2020 moves towards total reductions for the oil sands of 120 million tonnes by 2050. While not shown in the Figure 4.3, ***by 2050 the reduction from CCS coupled with nuclear energy would enable the oil sands to produce at 2030 rates with zero emissions being released, creating the cleanest sources of produced crude oil on the planet***.

Based upon ongoing financial and regulatory support by government, industry will increase CCS capacity by 8 million tonnes per year from 2020 to 2030, or from 50 million tonnes to 130 million tonnes by 2030. Of this increase, 60 percent goes towards oil sands projects. This is indicated in the figure below by the area CCS Additional and Widespread Adoption.

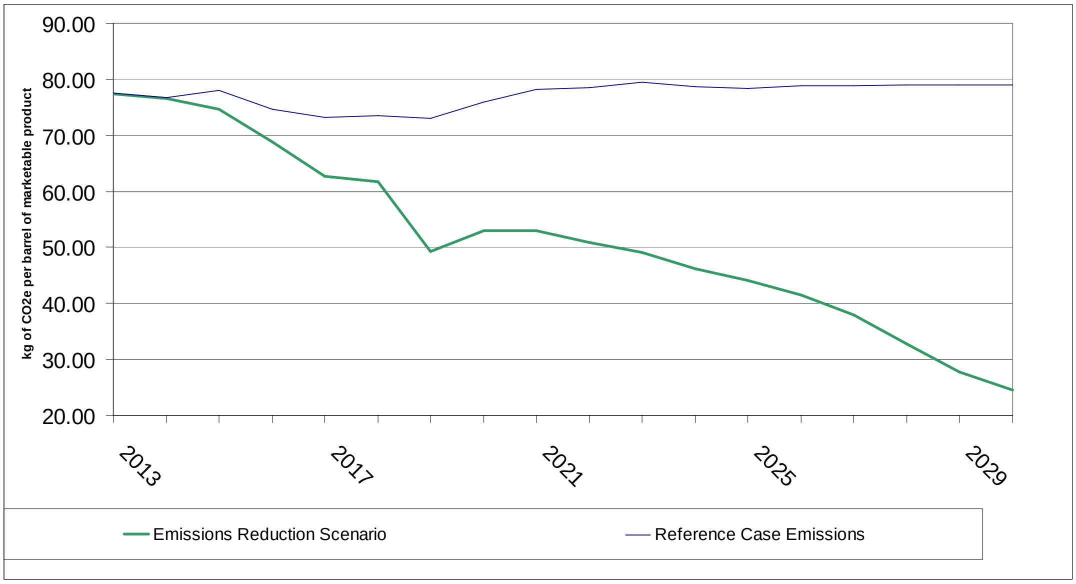
Figure 4.3 Total Emissions (MT of CO2e/year)



On a per barrel basis, the reduction may be more visually appealing. Figure 4.4 is based upon the information used to determine Figure 4.3. We have changed the emphasis to the emissions associated with a barrel of marketable product based upon the total emissions from the industry and the corresponding output of marketable products. By 2030, the emissions are 69 percent less on a per barrel basis than they would have been under the status quo. The emissions, as an industry average, are estimated at 24.55 kg/bbl of marketable product.

[35] "Accelerating Carbon Capture and Storage in Alberta: Interim Report", September 30, 2008. Alberta Carbon Capture and Storage Development Council.

Figure 4.4
Industry Annual Average Emissions



If such a scenario unfolds in Alberta, the oil sands could pave the way as a bold new energy system, producing hydrocarbons to power our economy with almost zero GHG emissions being released into the atmosphere.

About CERI

The Canadian Energy Research Institute (CERI) is a co-operative research organization established through an initiative of government, academia, and industry in 1975. The Institute's mission is to provide relevant, independent, objective economic research and education in energy and related environmental issues. Related objectives include reviewing emerging energy issues and policies as well as developing expertise in the analysis of questions related to energy and the environment.

For further information, see our web site: www.ceri.ca