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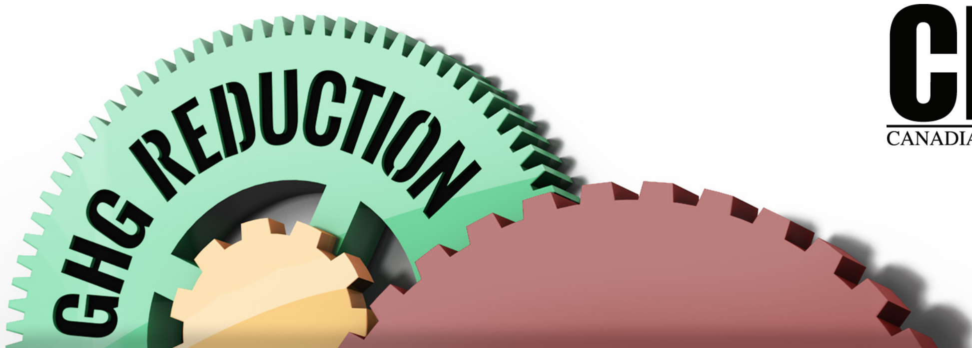

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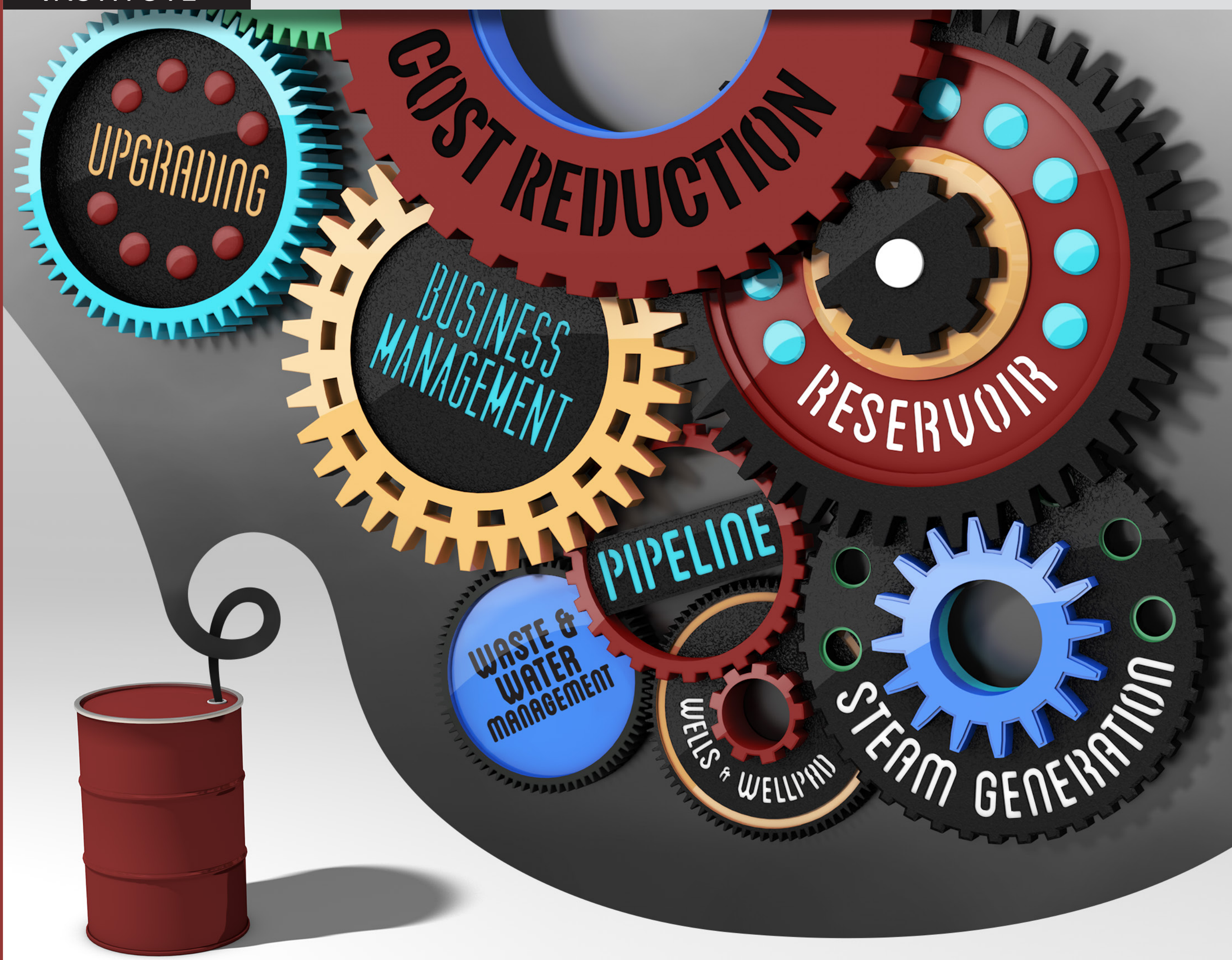
Economic Potentials and Efficiencies of Oil Sands Operations: Processes and Technologies



ECONOMIC POTENTIALS AND EFFICIENCIES OF OIL SANDS OPERATIONS: PROCESSES AND TECHNOLOGIES

Economic Potentials and Efficiencies of Oil Sands Operations:
Processes and Technologies

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Abbreviations

AER	Alberta Energy Regulator
BM	Business Management
CAPEX	Capital Cost
CCC	Cold Catalytic Cracking
CLS	Cold Lime Softening
CPF	Central Processing Facility
DCSG	Direct Contact Steam Generator
DDS	Digital Data Submission
DGF	Dissolved Gas Flotation
Dilbit	Diluted Bitumen
DO	De-Oiling
DSU	Desulphurization and Upgrading
EC	Electrolytic Cell
EJS with ARP	Enhanced Jetshear with Acid Reduction Process
ESAR	Environmental Site Assessment Repository
FC-OSSG	Forced Circulation Oil Sands Steam Generator
FWKO	Free Water Knockout
GF	Gas Flotation
Hi-Q	High Quality
HLS	Hot Lime Softening
HRSG	Heat Recovery Steam Generator
IGF	Induced Gas Flotation
KPIs	Key Performance Indicators
MPFM	Multiphase Flow Meters
OPEX	Operating Cost
ORF	Oil Removal Filter
OTSG	Once-Through Steam Generator
PAW	Process Affected Water
PIG	Pipeline Inspection Gauge
PT	Pipeline and Transport
RES	Reservoir
RO	Reverse Osmosis
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic Crude Oil
SG	Steam Generation
ST	Skim Tank
TDS	Total Dissolved Solids
UPG	Upgrading
WCS	Western Canadian Select
WLS	Warm Lime Softening
WPMS	Well Pad Manufactured Solution
WTI	West Texas Intermediate
WWP	Wells and Well Pads
WWT	Water/Wastewater Treatment
ZLD	Zero Liquid Discharge

Executive Summary

Whenever the WTI price increases by one Canadian dollar, Canadian GDP is estimated to gain about $1.7 billion.[1] Similarly, a reduction in production costs of Canadian oil is likely to bring a comparative benefit to the economy. The Bank of Canada estimates that the lower oil and commodity prices since 2014 resulted in a 1 percent drop in Canada's GDP and a loss of ~$60 billion in national income[2]. These underscore the role of production cost reductions in the competitiveness of Alberta's oil sands industry and the Canadian economy in general.

Given the unstable and current low oil price environment, booming US shale oil production, global oil supply glut, increasingly stringent emissions regulations, and social pressure to reduce GHG emissions, the survival or growth of the oil sands industry will depend on how quickly it can innovate to address these challenges.

This study shows that the costs and emissions challenges facing the oil sands industry are real and serious, and if not urgently addressed may stunt the growth of the industry. The 100 $MtCO_2eq$. emissions per year cap imposed on the oil sands industry will be reached by 2028. This means that the industry has about 10 years to act in order to continue oil sands production growth by reducing its emissions intensity. On the other hand, high bitumen supply cost is another important factor that makes oil sands production less competitive relative to other competing world crude oils.

This study identifies clear technological pathways that will enable the oil sands industry to significantly reduce costs as well as emissions. Six technology configurations that reduce both bitumen supply costs and GHG emissions are identified: one for brownfield and five for greenfield developments. With the implementation of any of the configurations, chances of reaching the 100 MtCO2eq./year cap are reduced to zero within the study period (2016-2036).

[1] Millington, D., 2016. Low crude oil prices and their impact on the Canadian economy. Canadian Energy Research Institute Study Report No. 156. February 2016. Available online at http://resources.ceri.ca/PDF/Pubs/Studies/Study_156_Full_Report.pdf

[2] Statement made by Lynn Patterson, the Deputy Governor of Bank of Canada at the Edmonton Chamber of Commerce on March 30, 2016

Table E.1: Optimal Technology Configurations for Brown and Greenfield Developments

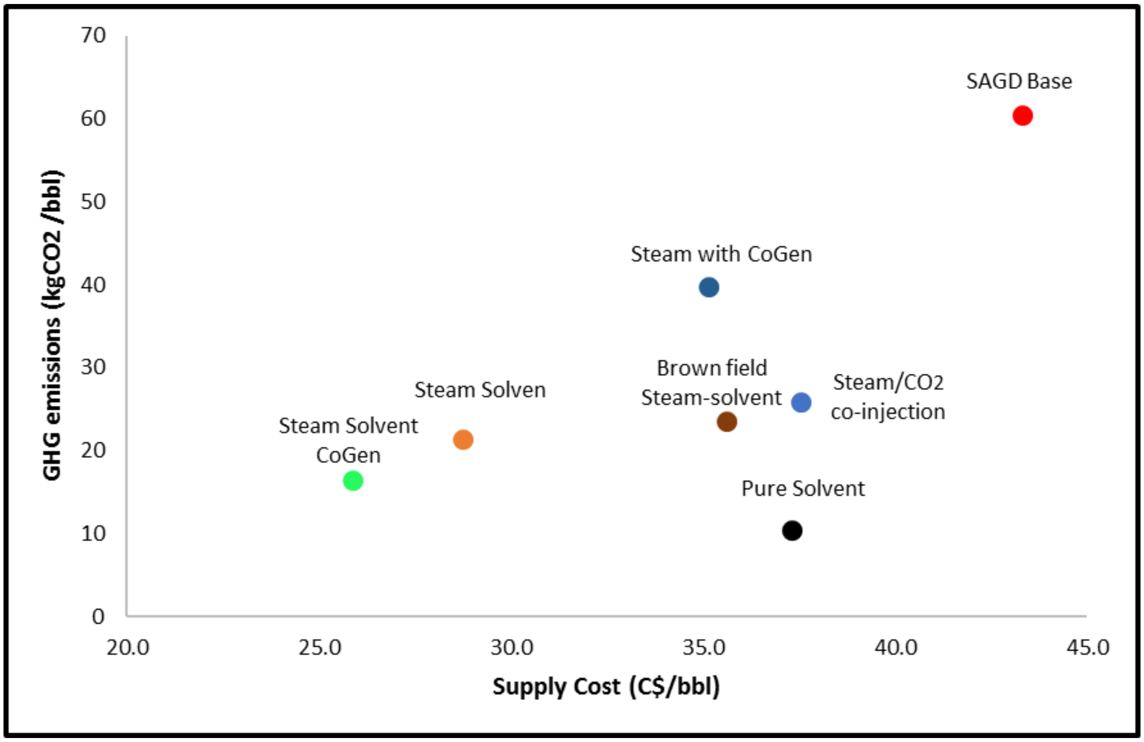
	Compatible Processes and Technologies					
	Business Management & Data Analytics (BM)		Wells and Well Pads (WWP)	Reservoirs (RES)	Water and Waste Treatment (WWT)	Steam Generation (SG)
Brownfield development						
Steam solvent		Steam flood management		Steam Solvent	Magox precipitation and CO_2 conversion	OTSG
Greenfield development						
Steam with CO_2 co-injection	Digitalization of EPC	Steam flood management	Well pad standardization	Steam/CO_2 co-injection	Evaporator	DCSG
Steam with CoGen				Steam		SOFC
Steam-solvent				Steam Solvent	Chemical water treatment	RT-OTSG
Steam-solvent Cogen						SOFC
Pure Solvent				Pure Solvent		

Source: CERI

The technology configurations that meet the minimum costs and emissions objective criteria will allow for significantly more room for oil sands production growth. These technology configurations have the potential to reduce bitumen supply cost by 34-40 percent, reduce fuel-derived emissions from in situ oil sands production by more than 80 percent, and consequently delay the time until the emissions cap is reached by several decades.

Figure E.1 shows the impact on supply cost and emissions by the identified optimal technology configurations applicable to green and brownfields.

Figure E.1: Combined Impact of Technologies under Different Cost and GHG Emissions Scenarios



Source: CERI

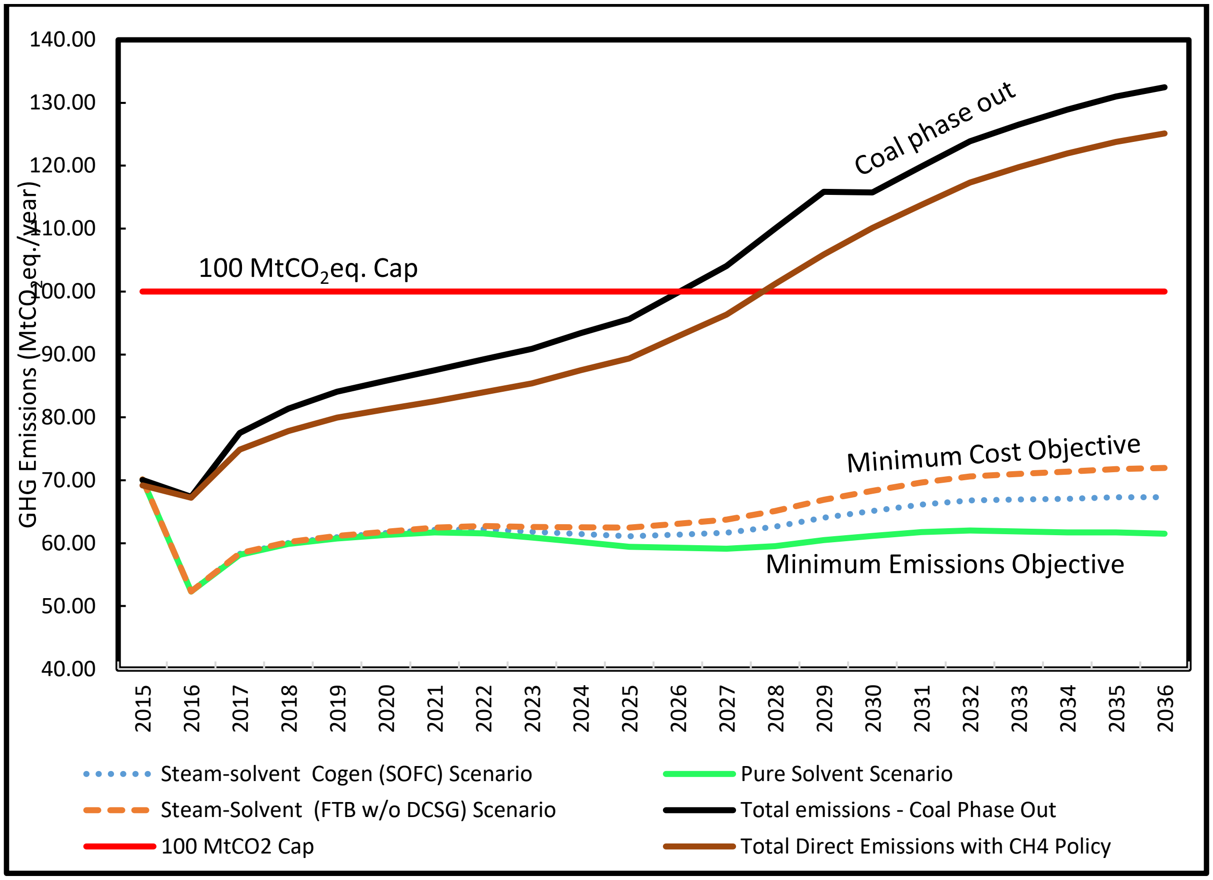
Reducing emissions usually comes with a cost penalty. Interestingly, the results of this study prove otherwise. They show that emissions and cost reduction objectives are not adversely related. This means the two objectives can be achieved simultaneously. Even more interesting is the fact that by simply choosing to implement the minimum cost objective configuration, dramatic emissions cuts are made as a result.

The different technology configurations (in Table E.1 and Figure E.1) result in new direct emissions profiles[3] for the oil sands industry and these are compared with the business as usual profile (***BAU with policy changes***[4]***)*** and the ***100 MtCO$_2$ cap*** in Figure E.2.

[3] Based on the oil sands production forecast generated in CERI's 2016 oil sands update.

[4] The profiles in Figure E.2 include current direct and indirect emissions of all the oil sands production methods (mining, in situ, enhanced oil recovery and primary heavy oil production) and upgrading.

Figure E.2: GHG Emissions Profile for the Oil Sands Industry and the 100 $MtCO_2$/year Emissions Cap



Source: CERI

The new GHG emissions profiles[5] based on the optimal cost and emissions technology configurations will allow for oil sands production growth. These technology configurations have the potential to reduce bitumen supply cost by 40 percent, and avoid reaching the 100 Mt CO_2eq. per year cap during the study period (2016-2036).

However, further research and development work is needed to de-risk the promising technologies through pilot and field demonstration studies if the prospects of delivering these costs and emissions reductions are to be realized. For more information on possible ways of how to fuel a greener and more cost competitive oil sands industry, see the Appendix.

[5] Based on the oil sands production forecast generated in CERI's 2016 oil sands update.

Key Findings

The key findings of this study are presented below:

1. The 100 $MtCO_2eq$. emissions per year cap imposed on the oil sands industry will be reached by 2028. This means that the industry has about 10 years to act to raise the ceiling on oil sands growth by reducing its emissions intensity.

2. High bitumen supply cost is another important factor in the competitiveness of the oil sands industry.

3. Identification of clear technological pathways to significantly reduce costs as well as emissions. With the implementation of any of the configurations, chances of reaching the 100 $MtCO_2eq$./year cap are eliminated within the study period (2016-2036).

4. The technology configurations that meet the minimum costs and emissions objective criteria can achieve potential reduction of bitumen supply cost by 34-40 percent, reduce fuel-derived emissions from in situ oil sands production by more than 80 percent, and consequently delay the time until the emissions cap is reached by several decades.

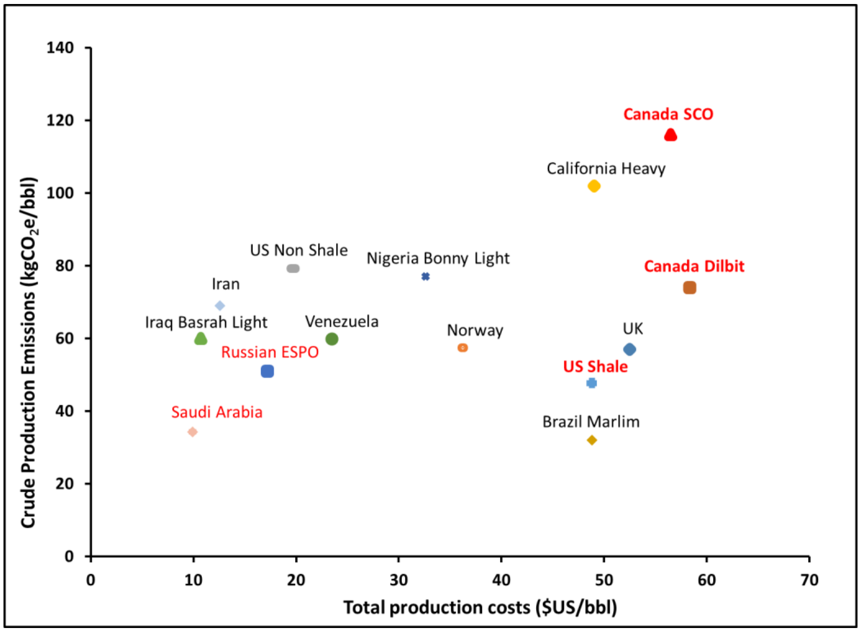
5. Emissions and cost reduction objectives are not adversely related. For example, by choosing to implement the minimum cost objective configuration, dramatic emissions cuts are made as a result.

6. Further research and development work is needed to de-risk the promising technologies through pilot and field demonstration studies if the prospects of delivering these costs and emissions reductions are to be realized.

Chapter 1: Introduction

Extraction of bitumen from oil sands resources has brought significant economic benefits to the province of Alberta and across Canada through the delivery of services, tax revenues, royalties and job creation. However, the oil sands industry is faced with several challenges, including access to markets, high production costs, and high energy and emissions intensities compared to conventional and non-conventional crude counterparts.

Figure 1.1: Production Costs and Greenhouse Gas Emissions of World Crude Oils



Source: Rystad Energy, UCube, IHS Energy, CERI.

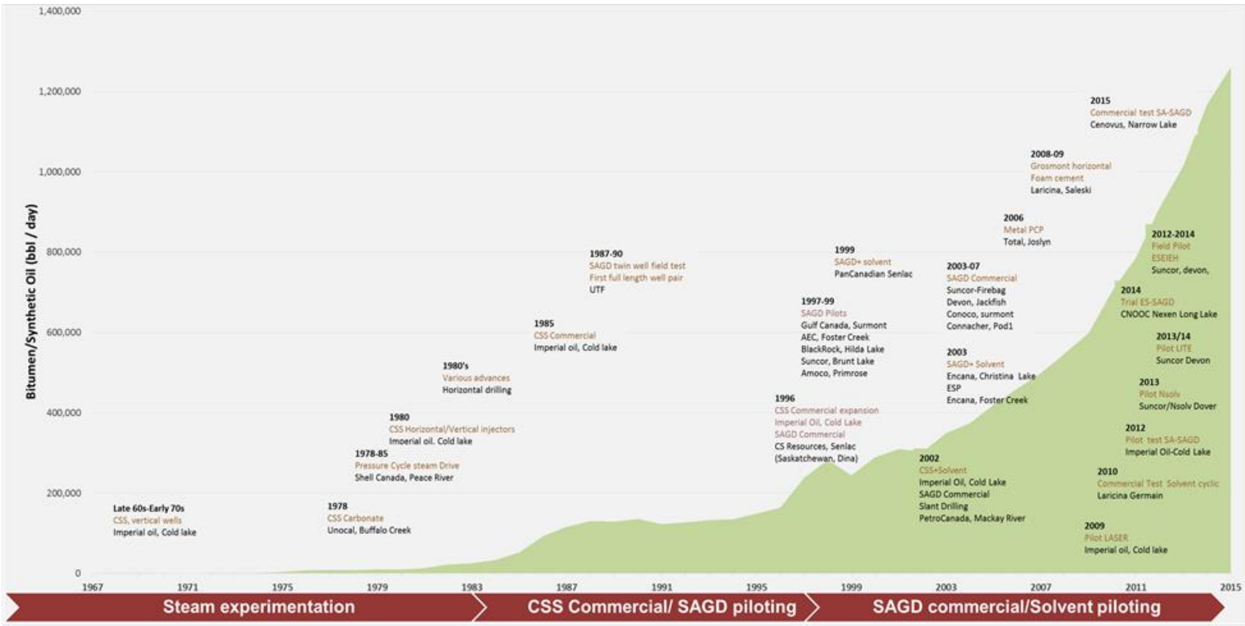
The two important challenges of high costs and emissions are evident from Figure 1.1, which shows that West Texas Intermediate (WTI)-equivalent diluted bitumen (dilbit) and bitumen upgraded to synthetic oil (SCO) have the highest average production costs and GHG emissions when compared to other world crude oils. For example, the WTI-equivalent price of dilbit and SCO are US$58.32 and US$56.50, respectively. Emissions-wise, production of dilbit and SCO results in 74 kgCO_2/bbl and 116 kg CO_2/bbl, respectively.

On the other hand, the major competing international crudes (e.g., US Shale, Saudi Arabia, Russia, etc.) have lower average costs and emissions. Therefore, there is an important need to boost the competitiveness of the oil sands bitumen product from Alberta by reducing its production costs and associated GHG emissions to equal or lesser values than that of a conventional crude barrel.

Of the estimated 1.7 trillion barrels (bbl) of oil sands in place hosted in clastic (mainly the Cold Lake, Peace River, and Athabasca deposits) in Western Canada and carbonate (mainly the

Grossmont formation) reservoirs, only about 10 percent (167.9 billion bbl) of the resource is considered recoverable by using existing technologies.[6] About 80 percent of the recoverable resources are too deep to mine; thus, these can only be extracted using *in situ* technologies.

Figure 1.2: Pictorial Event Timeline of In Situ Oil Sands Technology Development and Production Growth



Source: CERI

As shown in Figure 1.2, oil sands bitumen extraction has experienced significant growth through the development and commercialization of innovative *in situ* technologies. The two primary *in situ* technologies are Cyclic Steam Stimulation (CSS) and Steam-Assisted Gravity Drainage (SAGD), the latter being the most predominantly applied and the most economically viable technology for most reservoir types.

The SAGD process came about as a result of technical innovation led by Dr. Roger Butler and his colleagues.[7,8] Most of its development was carried out in the Underground Test Facility (UTF) at the Alberta Oil Sands Technology and Research Authority (AOSTRA) facility in the late 1970s (see Figure 1.2).

[6] AER, 2012. ST98: Alberta's energy reserves & supply/demand outlook. Available online at https://www.aer.ca/data-and-publications/statistical-reports/st98

[7] Butler, R.M., McNab, G.S., Lo, H.Y., 1981. Theoretical Studies on the Gravity Drainage of Heavy Oil during Steam Heating.

[8] Butler, R.M., Stevens, D.J., 1981. The Gravity Drainage of Steam-Heated Heavy Oil to Parallel Horizontal Wells. J. Can. Pet. Technol. 20, 90–96.

The extraction of bitumen at the levels accomplished today would not have been possible but for innovation, which remains the key factor in successful oil sands development. Figure 1.2 gives a historical perspective as to how past innovation efforts in the oil sands yielded significant results over the years. However, the innovation of many decades ago is no longer adequate in the face of low oil prices and an increasing demand for sustainable environmental processes and reduction in greenhouse gas emissions.

Oil sands industry experts and executives, academics and policy makers believe that the current challenges, particularly those related to high supply costs, energy intensity and emissions are to be solved through technical innovation. It is expected that industry must keep up with the pace of innovation to meet the changing commodity price realities and environmental sustainability expectations of the twenty-first century. Therefore, new and innovative technologies are needed to exploit the huge reserves in Western Canada in a responsible and sustainable manner.

A few previous studies[9,10] cataloged technology options and their potentials and limitations related to mostly environmental, regulatory and economic impacts in the oil sands. The Council of Canadian Academies scoped already deployed and emerging technologies that could reduce the environmental footprint of bitumen extraction and processing. It evaluated the extent to which existing and emerging technologies can reduce the environmental footprint of all aspects of oil sands operations.

On the other hand, Findlay (2016)[10] explored several aspects of oil sands development and growth. The study looked at implications of the following on the oil sands growth outlook: perception, regulation, "social license", market access, price discount on oil sands bitumen, and oil sands cost competitiveness and economic outlook.

Though the Council of Canadian Academies described technologies, their potentials and timelines for commercial deployments, the potential cost and emissions reduction potentials of these technologies were not assessed or quantified.

There are obvious challenges to embarking on studies that estimate the potential reductions in cost and emissions of new and emerging technologies. These include:

1. Paucity of information on new and emerging technologies in publicly available literature given that in most cases the required information is proprietary.

[9] Council of Canadian Academies, 2015. Technological prospects for reducing the environmental footprints of Canadian oil sands. The expert panel on the potential for new and emerging technologies to reduce the environmental impacts of oil sands development. The Council of Canadian Academies, Ottawa, ON, Canada.
[10] Findlay, P.J., 2016. The Future of the Canadian Oil Sands: Growth potential of a unique resource amidst regulation, egress, cost, and price uncertainty. Report No. WPM 64. Oxford Institute for Energy Studies, Oxford, UK.

2. Lack of expertise – it is difficult to assemble a team of experts to carry out a detailed cost and emissions assessment of all the technologies across the process life cycle of oil bitumen extraction and supply.
3. Uncertainty in estimating the future cost trajectory of emerging technologies and processes with the attendant technical and market risks associated with the journey leading to product development and market deployment.

Objectives and Scope

The objective of this study is to identify new and emerging technology options that can be deployed in the oil sands industrial sector within the next 5-7 years and assess their potential to reduce GHG emissions and supply costs. This study is specifically focused on *in situ* process-based projects, spanning bitumen production, processing, upgrading, pipelines and transport.

From the options identified, the goal is to build scenarios of industry-wide technology adoption with the objective of improving the overall economic and environmental performance of the industry. The adoption scenarios are based on the oil sands production forecast generated in CERI's 2016 oil sands update.[11]

[11] Millington, D., 2017. Canadian oil sands supply costs and development projects (2016-2036). Canadian Energy Research Institute (CERI) Study No. 163. February, 2017. Available online at http://resources.ceri.ca/PDF/Pubs/Studies/Study_163_Full_Report.pdf

Chapter 2: In Situ Oil Sands Technologies

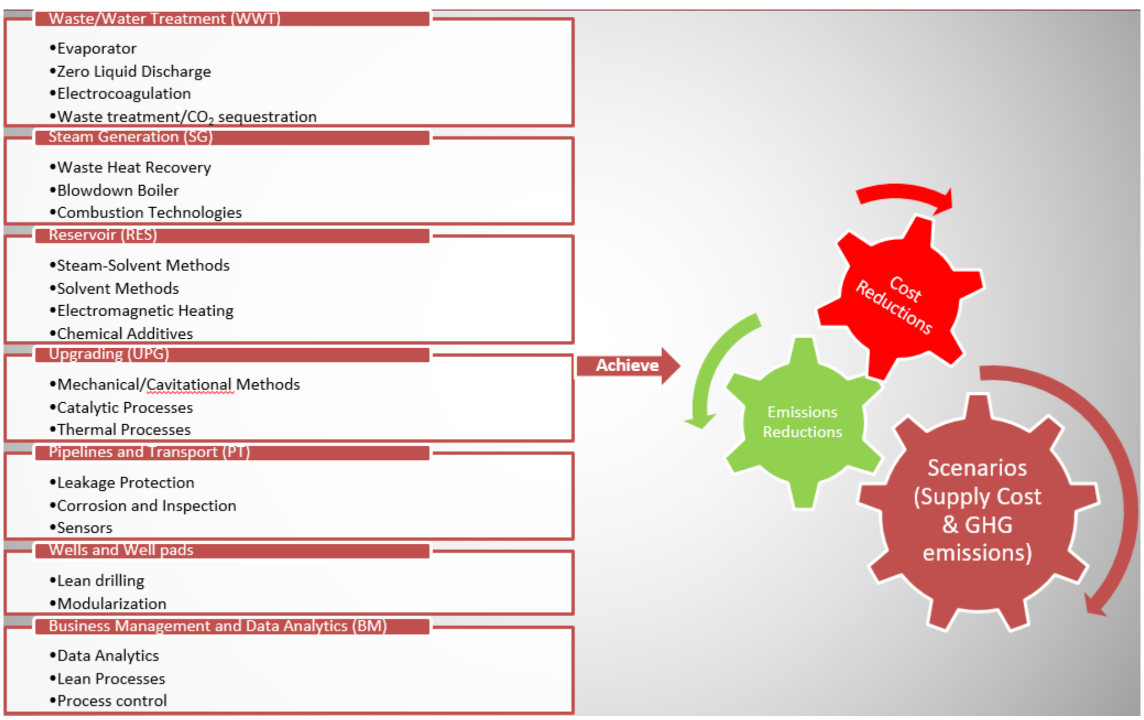
In this chapter, the description of new and emerging technologies and processes for deployment in oil sands bitumen production and upgrading are categorized and presented in seven distinct process segments.

In Situ Oil Sands Process Segments

The benchmark bitumen production and upgrading facilities are sub-divided into seven segments that constitute the oil sands process chain. Under each segment (Figure 2.1), different technologies identified to be deployable in the oil sands within the next 5-7 years are considered.

The process segments include the following: Water and Waste Treatment (WWT), Steam Generation (SG), Wells and Well Pads (WWP), Reservoirs (RES), Upgrading (UPG), Pipelines and Transport (PT), and Business Management and Data Analytics (BM).

Figure 2.1: In Situ Oil Sands Production and Processing Segments and their Associated Technologies



Source: CERI

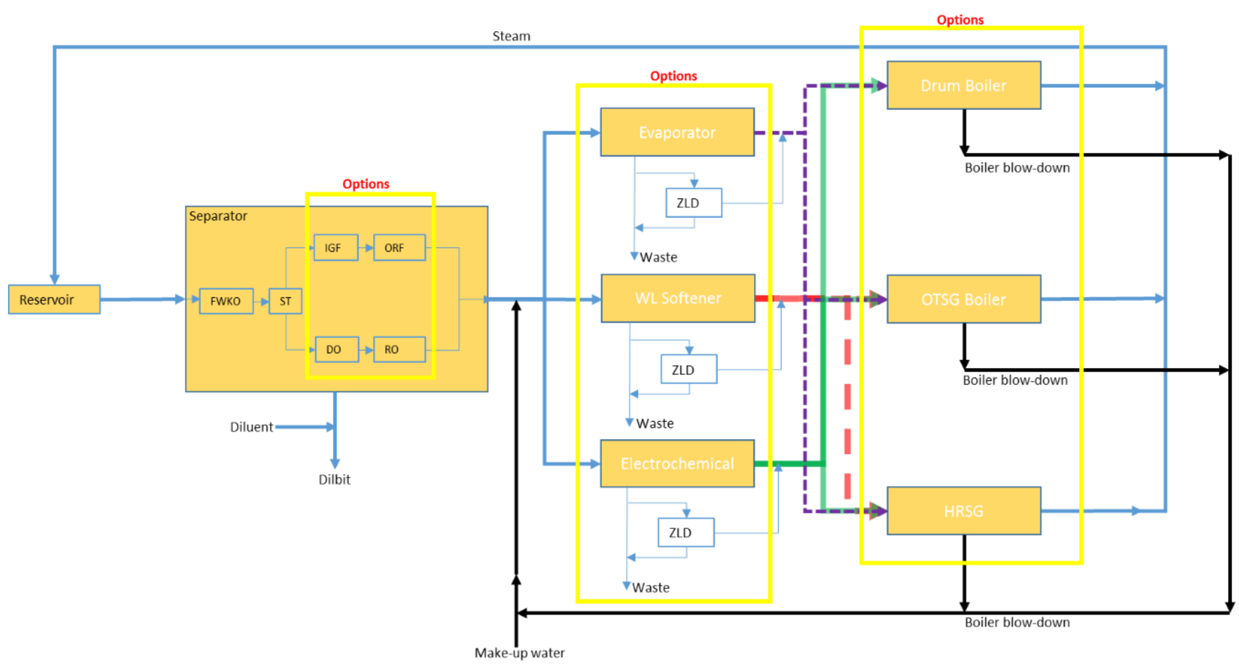
The WWT segment comprises technologies that can be applied in the following sub-segments: oil-water separations and water treatment, waste handling and emissions mitigation. The SG segment involves combustion and boiler technologies whereas the WWP segment is made up of technologies with potential applications in wells and well pads. Technologies that are applied in the sub-surface for oil exploration and to mobilize bitumen from the oil sands are listed and assessed under the RES segment. Various partial upgrading and deep conversion technologies are described under the UPG segment. Further, the PPT segment discusses technologies for pipeline safety, maintenance and monitoring whereas the BM segment is made up of lean business methods, intelligent business management and data analytics.

In the following sections, the technologies are described highlighting the major issues each innovation addresses. The strengths, weaknesses and potentials of the technology are presented.

Water/Wastewater Treatment (WWT) Segment

The product from the reservoir is a mixture of bitumen, water and other materials, which needs to be separated to recover the bitumen product and send the remaining stream forward for further treatment. The role of the WWT segment is to recover as much pure water as possible from the produced liquid so that the water can be reused for further production in the process.

Figure 2.2: Wastewater Treatment and Steam Generation Superstructure for SAGD Bitumen Production



Note: technologies and processes that are alternatives to each other are represented as options
Source: CERI

Figure 2.2 shows a superstructure of various processes and technologies that form the basis of innovations deployable for water/wastewater treatment. It also shows the interconnections of the WWT segment with the steam generation stage in a SAGD production facility. The water/wastewater treatment step can be subdivided into an oil and water separation unit and water treatment unit.

Oil and Water Separation

Separating the produced oil completely from the water is very difficult to achieve. This poses a challenge for the facility due to the tendency of remnant oil to degrade water treatment and heat transfer performances of the facility. Therefore, the adoption of efficient, reliable and affordable de-oiling technologies is important for water management in oil sands bitumen production facilities. Technologies that are used in the oil-water separation include:

- Free water knock-out (FWKO)
- Skim tank
- Induced static flotation (ISF)/Induced gas flotation (IGF)/Dissolved gas flotation (DGF)
- Oil removal filter (ORF)
- Reverse osmosis filter (RO)

Free water knock-out, skim tank and gas flotation steps separate the product stream from the reservoir segment into gas, oil and oily water streams. The oily water stream is passed through an oil removal filter to further remove any entrained oil in the produced water. Various options of the oil removal filter exist, but the nutshell filter is the most commonly used in oil sands bitumen processing.

Water Treatment

Here, treatment is aimed to remove hardness and silica from the de-oiled, produced water, and any make-up water that may be introduced into the process. The following technologies are available for the water treatment stage:

- Evaporator
- Lime softener
- Filters
- Ion exchanger
- Electrolytic cell
- Zero Liquid Discharge

As shown in Figure 2.2, some pairs of these technologies are mutually exclusive in the process, whereas others are complementary to each other. Silica and hardness treatment process in the oil sands industry often consist of three units: warm lime softening (WLS), after-filters, and weak acid cation (WAC) ion exchange.

Lime softening is used to remove hardness and silica. In the process, hardness ion – calcium and magnesium ions – react with added chemicals which convert them to small suspended solids.[12] Specifically, calcium is removed by converting it to calcium carbonate and magnesium is removed by converting it to magnesium hydroxide. The particles agglomerate and then settle to the bottom. Generated clear water can then be removed. The lime softening process can be broken down into three steps: reaction (converts hardness to low solubility salts), precipitation (happens after oversaturation of water with low solubility salts), and clarification (sedimentation of generated particles) steps.[12] The first two steps remove hardness from the produced water and the third step removes silica. Interestingly, silica can be removed by the precipitated hardness ions (by adsorption) with additional lime and magnesium hydroxide added to promote silica precipitation. Generally, the main function of the lime softener is to remove silica to a target of less than 50 mg/l.[13]

Lime softening is sub-divided into three categories based on the operating temperature of the process:

- Cold lime softening (15-60 ^{o}C)
- Warm lime softening (60-85 ^{o}C)
- Hot lime softening (90-110 ^{o}C)

Theoretical hardness in the effluent stream from the lime softening unit is:

- Cold lime softening (80-110 mg/L)
- Warm lime softening (30-50 mg/L)
- Hot lime softening (15-25 mg/L)

The residual hardness in a CLS effluent would be considered too high for SAGD process requirements. Thus, WLS and HLS are the types that are mostly deployed. The treated effluent from HLS or WLS can be sent to a boiler to generate steam for injection into SAGD wells. HLS is preferred for treating water for high pressure boilers, which require feed water with very low hardness.

Evaporators provide an alternative to the lime softening based treatment process. WLS works well with water that has a lower total dissolved solids (TDS) content <7000 ppm.[14] With higher TDS, more chemicals are required for the treatment which results in the formation of sludge. This can make the treatment ineffective and expensive as the amount of treated water coming out from the softener decreases. Consequently, very high TDS produced water is better treated using evaporators, and SAGD operators are prioritizing evaporator technologies for silica and hardness removal.14 Evaporators are known to provide high quality water treatment while maintaining high water recycle rates. Moreover, seeded slurry evaporative technologies have further optimized basic evaporators for use in SAGD applications with remnant oil carryover.

Filters are used in every water treatment process configuration. Generally, filtration serves to remove most of the bigger-sized or precipitated impurities in the water. The use of filters makes it possible to minimize the need for frequent equipment cleaning and servicing, avoid inefficient performance, and prevent damage to process components. Moreover, electrolytic water

[12] Toghraei, M., 2013. Lime Softening, Engrowth Training Inc.
[13] Dejak, M. and Portelance, S., 2016. The case for elimination of lime softening for produced water feeding OTSGs, Eco-Tec Inc.
[14] Lightbown, V., 2015. New SAGD technologies show promise in reducing environmental impact of oil sand production, Oil sand and Mining, Vol 1 (2), 2015.

treatment systems can be used instead of an evaporator or lime softener. Such systems apply the principle of electrolysis to precipitate dissolved ionic species from the produced water.

The filtered effluent from the lime softening step goes to ion exchange softeners. Various configurations of Weak Acid Cation (WAC) exchangers and/or Strong Acid Cation (SAC) exchangers can be used, depending on the attributes (TDS) of the feed water, but most operators use WAC due to increasing TDS from higher recycling rate requirements.[15]

The ion exchange softeners remove hardness, preventing scale buildup on the heat transfer surfaces on heat exchangers and the inner walls of the boiler; thereby, helping to maintain more efficient heat transfer. Adequate removal of hardness is critical for reducing the frequency of downtimes to clean the boiler tubes. Ion exchange softening is recommended whenever raw water hardness exceeds 1 ppm.14

In SAGD facilities, which do not have the option of deep-well disposal of the waste blowdown streams or facilities that aim to satisfy stringent water recycle requirements, zero liquid discharge (ZLD) is used to eliminate the generation of disposable water streams from the process.[16] Also, ZLD tries to limit the amount of wastewater that needs to be treated. With minimal wastewater generation, the necessary equipment for treating the remaining wastewater can then be determined and deployed according to the characteristics of the wastewater. The popular approach to ZLD is to use filtration technology to channel the drained liquid to an evaporator, and the evaporator concentrate can be sent to a crystallizer or spray dryer. As requirements on water usage and disposal continue to tighten, companies are geared to explore ZLD as an efficiency improvement and environmental conservation measure.

Challenges in the Water/Wastewater Treatment Segment

- Escaped oil from the oil-water separation stage can limit the effectiveness of water treatment and heat transfer downstream
- Water composition: High TDS process affected water consumes more treatment chemicals and produces more precipitates, resulting in lower recycle rates
- Low temperature requirement: most of the existing processes operate at a low temperature (about 90^{o}C), which requires the use of heat exchangers to cool the mixture (from about 140 ^{o}C) before the separation
- Fouling of the ion exchange softener by very small particles generated in the lime softener, leading to impairment of the performance of the softener and increased hardness leakage
- Some of the small particles (especially magnesium silicates) can get through to the boiler tubes and deposit there

[15] Dejak, M. and Portelance, S., 2016. The case for elimination of lime softening for produced water feeding OTSGs, Eco-Tec Inc.

[16] Lightbown, V., 2015. New SAGD technologies show promise in reducing environmental impact of oil sand production, Oil sand and Mining, Vol 1 (2), 2015.

- The small particles of calcium and magnesium can pass through undetected by most hardness analyzers
- Evaporators require more capital expenditure and higher energy use
- Non-evaporative processes require large blowdown ponds and can be more expensive to operate due to sludge
- GHG emissions intensity of the processes
- Need for higher produced water recycle rate
- Reliability and operability of the treatment technology [16]
- Corrosiveness of the process water on equipment
- Difficulty of cleaning treatment equipment, especially when fouling is encountered, and the financial implications (lost production, cleaning costs, etc.) of the downtime
- Balancing water management requirements (with respect to the disposed and recycled amounts) with GHG emissions
- Variability of operating conditions between units in the process, e.g., HLS is easier to manage than WLS but the higher temperature of the treated effluent from HLS is a source of problems in the downstream ion exchange design and operation[17]
- Difficulty of controlling lime softeners for optimum performance as upsets of the upstream separation or treatment processes trigger the escape of hardness and further issues downstream

Emerging technologies in this segment aim to address some of these challenges. In the following sections, we elaborate on the emerging technologies and processes in the water/wastewater treatment area of a SAGD plant.

Emerging Water/Wastewater Treatment Technologies for the Oil Sands

CH2M: Adding Dissolved Mg in Lime Softening

This is an operational improvement concept that is applicable to the traditional water treatment unit with lime softening. In the traditional water treatment with lime softening, Magnesium Oxide (MgO or Magox) is added to process affected water (PAW) to form $Mg(OH)_2$ which adsorbs silica for removal from the water treatment segment. At higher pH, native dissolved Mg^{+2} – which is Mg from PAW and process recycle – precipitates, thereby reducing the amount of fresh MgO required to remove the same quantity of silica. Additionally, $MgCl_2$ which has higher silica removal efficiency than Magox could be used to remove more silica for a given quantity of available magnesium.[18] This processing approach has an estimated result of about 78 percent reduction in fresh Magox consumption, with up to \$1.23 million in annual Magox cost savings.[19] Also, some stack CO_2 can be used to generate carbonic acid which can be used to prepare the $Mg(OH)_2$ required for the treatment, thereby reducing the CO_2 footprint of the plant. Other side

[17] Toghrai, M., 2013. Water treatment with lime softening. Engrowth Training Inc.
[18] Martins, K., McCloud, M., Karimi, A., 2016. Step change advancement to decrease Magox demand and reduce silica in lime softening processes in produced water treatment. World Heavy Oil Congress 2016.
[19] Assumes magox cost of \$600/ton and in situ Magnesium concentration of 2 mg/l.

benefits include reduction of soda ash consumption in the process and the attendant reduction of the total dissolved solids (TDS) in the processed effluent stream (due to reduced residual sodium from soda ash addition).[18]

The silica removal mechanism is understood to be a combination of adsorption and complex ion formation.[20] One challenge with the proposed use of stack CO_2 in this process is that, as the gas is cooled, sulfuric acid is produced by condensation of vapour which would require that equipment be able to resist strong acids.[18] CERI's calculations indicate that the CO_2 sequestered is so small that it does not offer any significant reduction in emissions of the facility.

GE: Next-Gen SAGD Process Affected Water Treatment Technology

This technology consists of oil-water separation and water treatment. The de-oiling step is a modification of the conventional de-oiling step by replacing the IGF and WSF with a custom de-oiling and high temperature reverse osmosis technology. The water treatment part consists of an evaporator. The configuration of the de-oiling step and water treatment unit results in an estimated 40 percent smaller size evaporator requirement, 26 percent lower capital cost, 29 percent lower annual operating cost, and 30 percent lower CO_2 emissions; while also improving plant availability and reducing land footprint.[21]

Vacom Systems: One-Step Process

It is the combination of heat exchanger and evaporator for water treatment that promises to prevent scaling and fouling of the boiler. Clear channel heat exchanger and MVR evaporation are used, and no pre-treatment (TSS removal, oil removal, anti-scalants, softening) is required.[22] The technology uses combinations of process regimes in the heat exchanger, involving process and mechanical design elements – such as turbulent flow, submerged boiling, low temperature cross – that have a collective impact on performance. The process can treat high TDS wastewater to distillate water with less than 50 mg/l TDS, and precipitates salts and brine in a salt slurry.[22] The slurry can be further dewatered for full ZLD. This process is said to be robust under constantly varying feed wastewater. The elimination of fouling and scaling challenges yield benefits in uptime and operations. However, additional investment in heat exchangers and the cost of operating the evaporator might be of concern.

[20] Bridle M., 2005. Treatment of SAGD produced water without lime softening, SPE International Thermal Operations and Heavy Oil Symposium, 1-3 November, Calgary, Alberta, Canada.
[21] General Electric & Suncor Energy, 2012. Next generation SAGD produced water treatment technology development. ESAA Watertech, 2012.
[22] Vacom Systems, 2016. Water conservation and oil recovery; One-Step Solution. World Heavy Oil Congress, September 6-9, 2016, Calgary, Alberta, Canada.

Eco-Tec: Elimination of Lime Softening for Produced Water Feeding OTSGs

A study by Bridle (2005)[23] found that with very low concentrations of hardness ions (magnesium, calcium and other metals), very little scaling occurs in a normally operating OTSG with high concentration of silica (350 mg/l) in the feed water. However, the operating guideline for OTSGs used in SAGD operations requires feed water to the steam generator to contain no more than 50 mg/l of silica.[24] But the produced water in the process have silica concentrations of 150-350 mg/l, and is usually treated by lime softening to reduce silica to below 50 mg/l.[24] This Eco-Tec technology proposes that by using efficient configurations of ion exchangers, lime softeners can be eliminated completely because it appears that it is the interaction of residual hardness with silica, in the OTSG, that leads to scaling of the boiler. This residual hardness can originate from very fine particles formed in the lime softener which find their way to the OTSG or impair the performance of the ion exchange softener so that hardness leakages occur in the ion exchanger. Various analysis of the scale formed in OTSGs indicate the presence of calcium, magnesium, and iron, in addition to silica.[24]

The technology is based on the premise that prevention of silicate scales under OTSG conditions can be achieved by aggressive control of hardness rather than silica reduction.[24] The level of hardness that allows elimination of lime softening is reported to be less than 0.1 mg/l.[24] The proposed water treatment system would be made up of advanced filtration which can significantly reduce oil and solids, followed by ion exchange softening. The ion exchange softening can be done in a few softener configurations. However, one advanced form, proven in operation in heavy oil production in California, features advanced brine regenerated SAC/WAC ion exchanger systems, which can reduce hardness to below 0.1 mg/l and magnesium to parts per billion proportions in the boiler feed water. The boiler blowdown is concentrated with silica (about 200 ppm), which can be used to sequester up to 5 percent of the CO_2 produced in the facility. Overall GHG reduction from the process is reported as 10-20 percent. Overall CAPEX and OPEX reductions are said to be 50-70 percent each.[25]

Connacher Oil and Gas: Processed Water Treatment with Evaporators

This is an evaporator-based system for water treatment. The use of evaporators in water treatment results in a boiler feed water stream with high enough quality for a standard drum boiler to be used in the process. Drum boilers can be desirable because they are less costly to operate and less water-intensive than OTSGs. The evaporator and drum boiler configuration is estimated to be able to reduce boiler blowdown to about 3 percent when compared to the typical 20 percent of OTSG's.[26] There is also an efficiency gain of about 5 percent from using a drum boiler.

[23] Bridle M., 2005. Treatment of SAGD produced water without lime softening. SPE International Thermal Operations and Heavy Oil Symposium, 1-3 November, Calgary, Alberta, Canada
[24] Dejak, M. and Portelance, S., 2016. The case for elimination of lime softening for produced water feeding OTSGs, Eco-Tec Inc.
[25] Assuming water treatment constitutes 30% of overall CAPEX
[26] PWC Energy., 2013. Innovation surge sparks oil sands opportunities.

Evaporators can achieve a produced water recycle rate in excess of 90 percent even for TDS levels above 24,000 ppm (PWC Energy). However, they are known to have higher energy intensity in comparison to softeners (due to their electricity or utility steam needs), leading to higher GHG emissions, about 7 to 8 percent more than a lime softening arrangement.[26] However, the footprint can be significantly lower if electricity related emissions are not included.

Veloia: Seeded Slurry Evaporative Process – Silica Sorption

First generation evaporative processes use large amounts of chemicals (caustic, chelants, dispersants, etc.) to keep the scaling species soluble. The use of these chemicals is costly and does not always provide scale-free operation which results in additional chemical or mechanical cleaning. High-hardness brackish makeup water is particularly difficult to process with elevated pH levels in the evaporators without pre-treatment. Disposal of high pH evaporator concentrate also requires large amounts of chemicals in order to produce brine that is suitable for deep-well discharge. The Silica Sorption Process offers significant improvements in evaporation system economics and operation when compared to standard evaporative processes by reducing chemical consumption, precipitating contaminants and providing straightforward disposal options for evaporator concentrate.

The process eliminates the potential for silica and hardness-related scale by sorbing silica and co-precipitating other compounds onto sorption crystals utilizing commercially available chemicals. Thus, the process can tolerate higher levels of hardness, remnant oils, and organics in the evaporation system. This provides the opportunity for use of high-saline, high-hardness make-up rather than fresh water. Anticipated benefits of this technology include: capital savings by as much as 25 percent, footprint reductions of 30 percent and operating cost savings by up to $2 per barrel per day when compared to traditional lime softening. Reduced liquid discharge (RLD) and zero liquid discharge (ZLD) crystallizers can capture more water and reduce more disposal waste with the silica sorption process.

WorleyParsons: Front-to-back Central Processing Facility

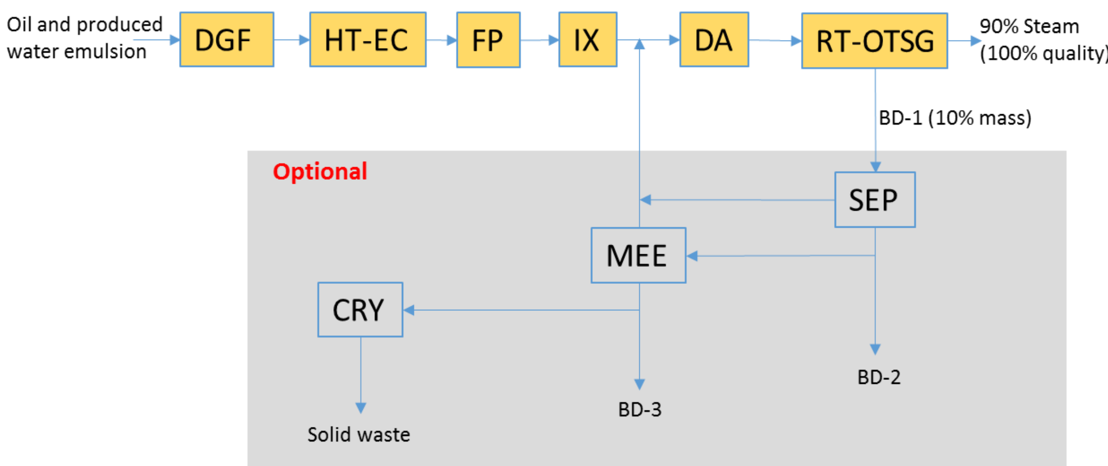
The idea of the front-to-back (FTB) process is to replace the conventional de-oiling and water treatment units with a different configuration that is made up of a Dissolved Gas Flotation (DGF) unit, a high temperature electrocoagulation (EC) unit, a filtration step, and rifle tube boiler. An ion exchanger could be added after the filter press for polishing. The electrocoagulation unit consists of 7 cells with 220 electrodes which are made of iron.[27] An electrical charge is applied to the electrode, making contaminants such as suspended solids and oily emulsions to cluster while oxidizing dissolved minerals. Among the anticipated benefits of this technology are: CAPEX reduction of 32 percent over a conventional water treatment with lime softening and OTSG boiler, OPEX reduction of $2 per barrel per day, with 6.2 percent reduction of OTSG fuel, annual

[27] Nischal, A and Portelance, S., 2016. FTB-CPF as a low-cost alternative for water treatment in heavy oil plants. World Heavy Oil Congress, September 6-9, 2016, Calgary, Alberta, Canada.

GHG emissions reduction of 60,000 tons, in addition to about 50 percent land footprint reduction.[27]

Electrocoagulation is one of several electrochemical techniques for water treatment. Other electrolytic cell technologies include sedimentation, flotation, and filtration.[27] The EC method removes the dissolved solids in the produced water by electrically generating the coagulant and floating the sludge using a gas (methane, nitrogen, hydrogen). It often uses an iron electrode which ionizes by the release of electrons that are used to precipitate dissolved ions in the produced water. The high temperature EC process can operate at temperatures nearing 95°C.

Figure 2.3: Process Flow Diagram of the FTB Process



Source: CERI

As depicted in Figure 2.3, there are four options for handling the blowdown from the process, including: BD-1, BD-2, BD-3, and solid waste discharge. The first three blowdown options are reduced liquid discharge (RLD) options, whereas the solid waste discharge option is a zero-liquid discharge (ZLD) option that may handle 35 percent of the BD-1 stream. A medium pressure separator (SEP) can remove additional water from the BD-1 stream (about 30 percent mass of BD-1), while the multiple-effect evaporator (MEE) removes another 35 percent water content. Some CO_2 from the stack gas could be sequestered with the BD-3 or the solid waste streams to give a small reduction of the process emissions.

ENCON, Saltworks, IDE Technologies: Zero Liquid Discharge Solution

The ENCON ZLD solution uses evaporation technology that allows for handling a wide range of waste streams. The technology can use either mechanical vapor compression (MVC) or thermal evaporation, using a variety of heat sources, such as natural gas, propane, fuel oil, waste oil, steam, or electricity.[28] Available capacities range from 40 to 4,000 gallons of distillate per hour

[28] ENCON Evaporators, Zero liquid discharge wastewater treatment, Online publication on www.evaporator.com, accessed September 2016.

for MVC evaporators and 8 to 400 gallons per hour for thermal evaporators. The reported operating costs range from US$0.01 to $0.02 per gallon of distillate.[28]

Saltwork Technologies markets SaltMaker – another ZLD technology – which uses waste heat to treat the produced water through four humidification-dehumidification steps. The energy requirement of the process is reported as 8 kWhe/m^3 electrical energy and 150-200 kWht/m^3 thermal energy at 85^{o}C.[29] SaltMaker has a modular design with an automated self-cleaning capability which can reduce downtime.

IDE Technologies has a ZLD technology that is based on thermal evaporation and crystallization. They also have a similar technology for produced water treatment. The water treatment technology is adapted from heavy oil produced water treatment. It uses a multi-effect evaporator which has different operating conditions within each stage of the system. Its horizontal orientation enhances energy efficiency and allows for easier management of the evaporator. The technology is estimated to use 30 percent less power than the conventional evaporator technologies. The field demonstration is sized for approximately 250 m^3/day of produced water.[30]

ZLD mainly serves to satisfy regulatory requirements on water and waste management within a SAGD facility.

Table 2.1 summarizes the discussed water/wastewater treatment technologies.

[29] Saltworks, Saltmaker evaporator crystallizer, http://www.saltworkstech.com/saltmaker-evaporator-crystallizer/
[30] IDE Technologies, Falling film evaporator, http://www.ide-tech.com/blog/publication/ide-showcases-falling-film-evaporator-sagd-water-treatment-canada/

Table 2.1: Summary of Water/Wastewater Treatment Technologies

Technology/ Company	Brief Description	Economic Factors	Environmental Factors
CH2M	Adding Dissolved Mg in Lime Softening	-78% reduction in fresh Magox consumption; -$1.23 million in annual Magox cost savings	-reduction of soda ash consumption; -not significant reduction in emissions from sequestered CO2.
GE: Next-Gen SAGD process	Custom de-oiling and high temperature reverse osmosis technology	-26% lower capital cost; -29% lower annual operating cost	-30% lower CO2 emissions; -reduction in land footprint
Vacom Systems: One-Step process	Prevention of scaling and fouling of the boiler	-additional investment in heat exchanger; -higher cost of operating the evaporator	-robust under constantly varying feed wastewater; -benefits in uptime and operations
Eco-Tec	Elimination of lime softening for produced water feeding OTSGs	-50-70% reduction in CAPEX and Opex	-sequester up to 5% of the CO2; -10-20% overall GHG reduction
Connacher Oil and Gas: Processed water treatment with evaporators	The evaporator and drum boiler configuration for water treatment	-about 5% efficiency gain; - drum boilers are less costly to operate and less water intensive than OTSGs.	-produced water recycle rate in excess of 90%; - about 7 to 8 percent higher GHG emissions
Veloia	Seeded Slurry Evaporative Process – Silica Sorption	-as much as 25% capital savings; -up to $2/bbl/d operating cost savings;	-footprint reductions of 30%; -Reduced liquid discharge (RLD) and Zero liquid discharge (ZLD) crystallizers can capture more water and reduce more disposal waste with the silica sorption process.
WorleyParsons: Front-to-back central processing facility	Configuration of a Dissolved Gas Flotation (DGF) unit, a high temperature electrocoagulation (EC) unit, a filtration step, and rifle tube boiler	-32% Capex reduction; -Opex reduction of $2/bbl/d.	-6.2% reduction of OTSG fuel; -60,000 tons annual GHG emission reduction; -about 50% land footprint reduction
ENCON, Saltworks, IDE Technologies: Zero Liquid Discharge solution	Uses evaporation technology that allows for handling a wide range of waste streams	-flexibility in choosing heat sources	-30% less power than the conventional evaporator technologies

Source: CERI

Steam Generation (SG) Segment

Steam generation is a critical part of the bitumen production process via Steam Assisted Gravity Drainage (SAGD). In oil sands in-situ recovery operations, Once-Through Steam Generators (OTSGs) are the most common type of boilers in use as they are more robust and can handle feed water with higher TDS content (<8000 ppm). In Western Canada, there about 170-200 OTSGs installed in various facilities.[31] However, OTSGs may face various operational challenges and should be coupled with a vapor-liquid separator to increase the steam quality prior to injection into a SAGD well. There are also some Heat Recovery Steam Generators (HRSGs) that are associated with cogeneration power plants, and a few drum boilers that have been deployed in recent projects. Drum boilers are considered more reliable and efficient than OTSGs but must operate with higher quality feed water supply. A hybrid drum boiler known as a Forced Circulation Oil Sands Steam Generator (FC-OSSG) has also been utilized where it acts much like an OTSG from a maintenance perspective, but with the operational benefits of a drum boiler. A large portion of the feed water to the boiler comes from recycled produced water which is augmented with make-up water that is often drawn from saline aquifers. Table 2.2 shows a summary of the generally acceptable feed water quality requirements for OTSGs.

Table 2.2: Acceptable Quality of OTSG Feed Water

Attribute	Maximum Limit (mg/l)
Total hardness	0.5
Silica	50
Total dissolved solids	10,000
Oil	10

Source: Bridle, 2005

The OTSGs are normally designed for 80 percent steam quality, but many run between 70 percent to 80 percent steam qualities, and 78 percent is considered the industry standard.[32,33] Of the remaining 22 percent that is mostly liquid, about 7 percent is blowdown which could be sent to a disposal well to get rid of hardness and silica, and about 15 percent is recovered and returned back to the process. The presence of impurities in the boiler feed water, due to poor treatment or treatment limitations occasioned by economic and/or operational constraints, necessitate the retainment of a portion of the fluid as liquid so that the impurities can stay in that phase.[33] If the liquid were to be completely vaporized, the impurities would drop out of solution/sludge and deposit onto the internal walls of the boiler tubes; creating sites for overheating and likely damage to the flow channels.

[31] Dejak, M. and Portelance, S., 2016. The case for elimination of lime softening for produced water feeding OTSGs, Eco-Tec Inc.

[32] ibid

[33] Innovative Steam Technologies Inc., 2016. SQ90 information package.

The following three main factors affect the operation of a boiler:

- Fluid flow regime – the phase(s) of the fluid flowing through the boiler pipes;
- Outlet steam quality – the phase(s) of the fluid exiting the boiler pipes;
- Radiant heat flux – the quantity of the heat contacting the boiler pipes as the fluid flows through them.

These factors can be controlled to avoid a dry out in the boiler – which poses the risk of scale deposition and failure of the pipes. For SAGD operations, the steam and water effluent from the boiler are separated with the dry steam sent downhole while the water is recycled or disposed. Table 2.3 shows the typical range of characteristics of the produced and make-up water in SAGD operations.

Table 2.3: Typical Range of Characteristics of the Produced and Make-up Water in SAGD Operations

Attribute	Produced Water (mg/l)	Make-up Water (mg/l)
Total dissolved solids	2,000-8,000	500-25,000
Total hardness	5-1,450	100-6,500

Source: Dejak and Portelance (2016)[34]

Challenges in the Steam Generation Segment

- Requirement of vapour-liquid separators to increase the steam quality as a consequence of the feed water quality and boiler efficiency
- Likelihood of OTSGs to experience dry outs in the boiler pipes at higher efficiencies
- Increasing feed water TDS content due to continual recycling and make-up water quality
- Maintaining the required boiler feed water quality for best performance in the face of upstream disturbances
- Overcoming the impact of poor upstream treatment on boiler performance
- The need for routine cleaning of boiler tubes which leads to downtimes and additional costs
- Fouling and scaling by unremoved oil, hardness, silica, and other materials result in lower efficiencies and potential for damage
- Water use and disposal regulations stipulating recycling requirement and blowdown stream limits

The emerging technologies in the SG segment aim to address some of these challenges. In the following section, we present the technologies that have been identified.

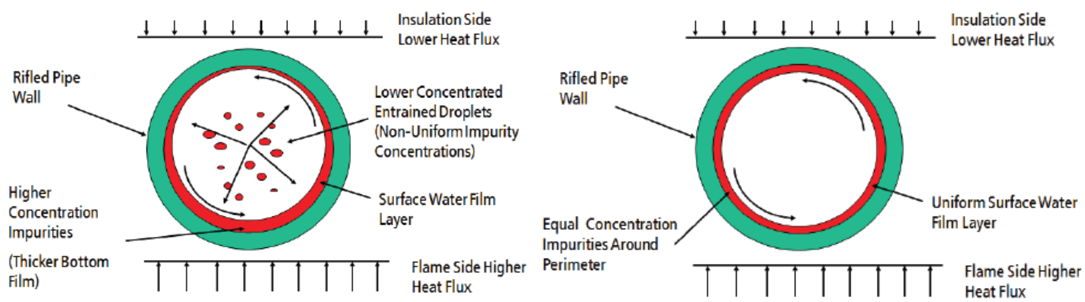
[34] Dejak, M. and Portelance, S., 2016. The case for elimination of lime softening for produced water feeding OTSGs, Eco-Tec Inc.

Emerging Technologies for Steam Generation

Innovative Steam Technologies: SQ90™ OTSG Design

This is a commercially available technology for deployment in the oil sands industry. With most OTSGs in the industry producing 78 percent steam quality, SQ90™ promises to take that to 90 percent while preventing dry outs. The technology is based on the use of rifled pipes within the radiant section of the OTSG. The use of rifled tubes is common in nuclear reactor designs where very high heat fluxes can be easily attained. The pipes are designed with a swirl pattern that induces a rotational flow to the fluid stream, thus, providing an even, wet layer on the pipe wall which promotes heat transfer to the liquid and reduced risk of dry out.[35] The stream travels through the tubing in a spinning motion, creating a centrifugal force that separates water from steam using less energy. This is unlike the traditional smooth pipes where liquid droplets tend to remain in the lower section of the pipe due to the affects of gravity. Figure 2.4 compares the cross-sectional views of a smooth pipe and a rifled pipe in operation.

Figure 2.4: Flow Profile in a Smooth Pipe and Rifled Pipe, Respectively



Source: IST

The OTSG can be operated in one of three modes: constant dry gas, constant firing rate, or constant feed water flow rate. Table 2.4 shows the attributes of the technology when operated at constant dry gas conditions. The technology vendor has also reported that feed water quality does not have to be better than what is currently being fed to the traditional OTSGs for the SQ90™ design to achieve 90 percent steam quality. The technology improves boiler efficiency through the reduction in feed water volumes required for a given steam load, thereby resulting in reduced water treatment cost.[35]

[35] Innovative Steam Technologies Inc., 2016. SQ90 information package.

Table 2.4: Attributes of SQ90TM Operated at Constant Dry Gas Conditions

Attribute	Value	Value	Value
Steam quality (%)	78	80	90
Feed water flow rate per OTSG (kg/hr)	130,625	127,359	113,208
Dry steam flow rate per OTSG (kg/hr)	101,887	101,887	101,887
Blowdown per OTSG (kg/hr)	28,737	25,472	11,321
Burner fuel heat input, LHV (MW)	78.17	77.26	73.31
Fuel consumed per OTSG (kg/hr)	8,091	7,998	7,587
CO_2 production per OTSG (kg/hr)	17,277	17,075	16,201

Source: IST Inc. (2016)[36]

There is a CAPEX premium which arises from the rifling of the pipe within the radiant chamber of the boiler. The overall additional capital cost above the traditional OTSG is reported to be within 2-5 percent. Also, the nature of the pipe design leads to pressure drop, and the pipes must be cleaned with a special pigging device that can clean the ridges and valleys in the pipe wall.

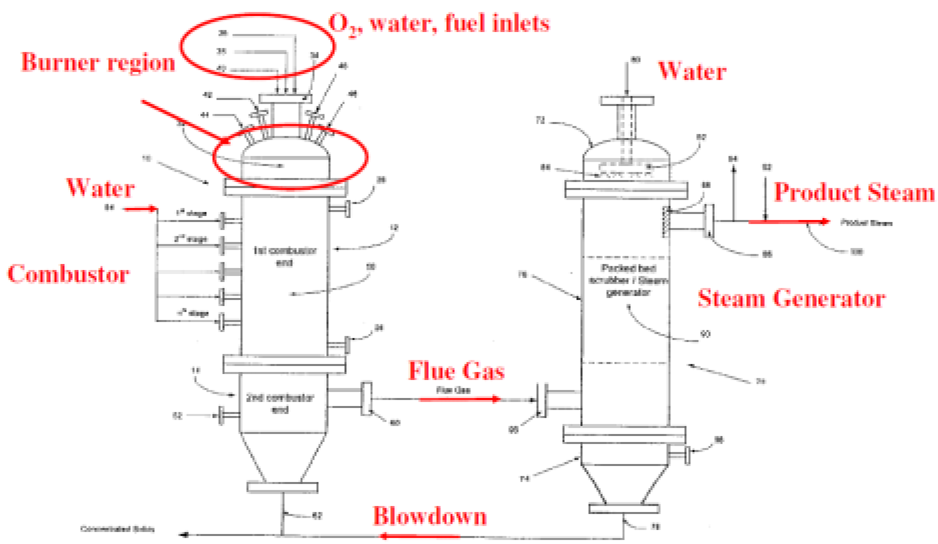
Natural Resources Canada: Direct Contact Steam Generation

Direct Contact Steam Generation (DCSG) is a technology that allows steam to be produced by directly contacting water with a hot gas in order to vaporize it without the need for boiler tubes. The hot gas can be high pressure, high temperature flue gas from the combustion of a fuel with pure oxygen or air. The use of oxygen is preferable for higher quality steam because nitrogen in the air moderates the flame temperature, reducing the heat available for vaporization of the water. The product gas from DCSG is estimated to contain about 90 percent H_2O and 10 percent CO_2.[37] The entire product gas is to be injected into a reservoir where some of the CO_2 is expected to be sequestered. Due to the nature of the boiler, thermal efficiency of the technology is estimated to be up to 98 percent. Any CO_2 that escapes to the surface can be recovered, by flashing the produced fluid, and recycled back to the combustor with the produced gas. Process simulation of DCSG with natural gas as fuel indicated the following potential benefits over a conventional SAGD process: reduction of produced oily water by 52.1 percent, reduction of total water-to-oil ratio by about 7.7 percent, decrease of energy intensity of SAGD by up to 7.6 percent, reduction of GHG emissions and make-up water intake.[37] Overall GHG reduction would depend

[36] Innovative Steam Technologies Inc., 2016. SQ90 information package.
[37] Clements, B.R. and Cairns, P. 2016. HiPrOx direct contact steam generation. Natural Resources Canada.

significantly on the amount of CO_2 that gets stored in the reservoir permanently. The technology developer estimates that up to 70 percent reduction could be achieved.

Figure 2.5: DCSG Process and Technology Design



Source: NRCan

Further benefits may also be derived through even smaller equipment sizes, greater portability, ease of separating and capturing CO_2, and higher steam production per fuel consumed. It is also expected that the use of DCSG will shrink much of the water treatment components of the conventional oil sands CPF into only a de-oiling unit. Figure 2.5 depicts the DCSG unit with its two compartments for combustion and steam generation.

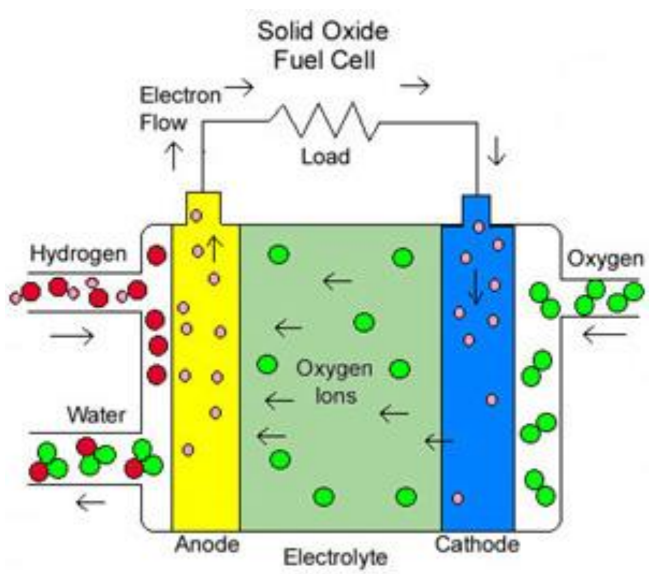
Although the process is expected to recycle any CO_2 that returns to the surface after injection, it is unlikely that it would be able to store all the CO_2 that is injected in the long run as accumulation of the gas in the reservoir would subsequently saturate it. Moreover, when oxygen is used for the firing, additional capital and operating cost requirements must be met for the oxygen supply facility and the air separation process. Other challenges for the technology include high temperature corrosion in the combustor likely due to the presence of hydrogen sulphide and organic acids when the process affected water is not treated prior to feeding it into the combustor. Also, the conditions in the steam generator may warrant the formation of carbonic acid in the product stream which poses further corrosion concerns.

Solid Oxide Fuel Cells for Cogeneration

Cogeneration is the simultaneous production of electricity and heat to meet power and heating needs. Typically, a gas turbine (GT) generates the electricity, and a heat recovery steam generator (HRSG) is used to produce steam. In the solid oxide fuel cell (SOFC), electricity is generated directly by chemically reacting a fuel and oxygen, rather than by combustion.[38] SOFCs operate at high temperatures which makes them relatively fuel-flexible. The fuel could be hydrogen, hydrocarbons or carbon monoxide. A typical design consists of three bonded layers: cathode, anode, and electrolyte, which separates the electrodes. The electrodes are electronic conductors and porous enough for gaseous diffusion through the electrode surface to the electrode/electrolyte interface. The electrolyte is permeable to the oxygen ion but not an electronic conductor.

As shown in Figure 2.6, oxygen flows across the outer surface of the cathode and reaches the cathode/electrolyte interface by pore diffusion. At the cathode side interface, the electrolyte (oxygen ion acceptor), the cathode (electronic conductor), and the pore (source of O_2) meet, and oxygen atoms are ionized with electrons from the cathode. Then the oxygen ions diffuse through the electrolyte to the anode side interface, where the electrolyte (oxygen ion donor), the anode (electronic conductor), and the pore supplying the fuel(s) meet.[39] An exothermic reaction occurs on this side; as the fuel(s) reacts with the oxygen ion to produce steam (and CO_2 if CO is present) – transferring electrons to the anode. The product(s) of the reaction are transported toward the outer surface of the porous anode in order to leave the cell. The product stream can be injected into the reservoir together with steam generated from the waste heat from the electrochemical reaction. Typical SOFC combined heat and power efficiency has been reported at about 80 percent at an operating temperature of about 1,000°C.[39]

Figure 2.6: Illustrative Diagram of a Solid Oxide Fuel Cell Operation



Source: Garrison (2016)[40]

[38] National Energy Technology Laboratory, SOFC Operation. Accessed November 15, 2016.
https://www.netl.doe.gov/research/coal/energy-systems/fuel-cells/operating-principles
[39] ibid
[40] Garrison, E. 2016. Solid Oxide Fuel Cells. Weblink accessed November 10, 2016:
http://mypages.iit.edu/~smart/garrear/fuelcells.htm

The economics of fuel cells as a heat and power source is found to improve in situations where the heat and power requirements do not change over time. The chemical reaction produces only water if only hydrogen is used as fuel, or water and carbon dioxide if a hydrocarbon (which is used to produce syngas) and/or carbon monoxide are used. Consequently, SOFCs are also ideal for carbon capture since the other product is water/steam. The challenge with SOFCs is that at a lower operating temperature the performance of the cells becomes increasingly poor. Reducing the operating temperature requirements can significantly improve economics as cheaper materials could be used in the design without compromising the durability of the fuel cells. A SAGD facility with SOFC could use methane reforming to generate syngas fuel. Therefore, overall costs and operating costs would be affected by natural gas prices. Data on SOFC capacities and costs were obtained from the Lazard database.[41]

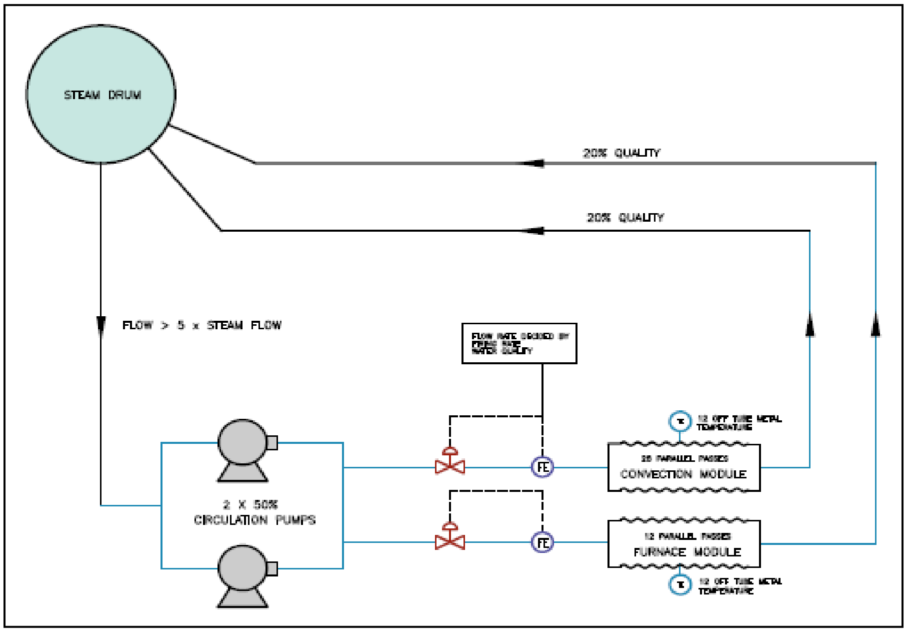
CleaverBrooks: Forced-Circulation Oil Sands Steam Generators

Forced-Circulation Oil Sands Steam Generators (FC-OSSG) combines the features of a typical OTSG with the advantages of a drum-boiler which allows it to operate like a drum-type boiler while managed like an OTSG. FC-OSSG is designed for ease of operation and maintenance like an OTSG while maintaining better reliability attributes of drum boilers. However, it differs from OTSG and drum boilers in that it uses a recirculation pump to draw water from a steam drum and push it through a heat transfer circuit containing a furnace and evaporator.[42] The recirculated water is heated in the circuit to produce steam. In the steam drum, steam is removed and liquid water is returned to the heat transfer circuit again. For each cycle, only 20 percent of feed water is converted to steam.[42] And the advantage of operating at a lower steam quality – i.e. high water content – is that it allows for lower concentrations of impurities in the water and more uniform temperature on the boiler tubes; since the temperature of the water-filled tube closely matches the water temperature rather than the hot gas temperature. This translates to lower rates of failure and cleaning requirements relative to an OTSG.

[41] Lazard. 2016. SOFC capacities and costs. Available at www.lazard.com

[42] Vasudevan M. 2012. Forced-circulation steam generator for SAGD applications, Cleaver-Brooks, 2012

Figure 2.7: Illustrative Diagram of the FC-OSSG Technology



Source: Cleaver-Brooks[43]

Although FC-OSSG can handle water quality upsets and higher steam loads, additional expenses are needed for the evaporator unit and pumping requirements. Figure 2.7 depicts the design and operation of the FC-OSSG technology.

ConocoPhillips and Total E&P: Gas-Turbine Once-Through Steam Generator

The Gas-Turbine Once-Through Steam Generator (GT-OTSG) produces both electricity and steam for SAGD operations. In this technology, waste heat from a turbine exhaust is used to produce steam in the OTSG. The OTSG uses a special burner that burns natural gas and a portion of the hot turbine exhaust; which makes the unit operate more efficiently than other cogeneration configurations while reducing the overall facility emissions. Carbon intensity reduction by this technology has been estimated at 17 percent (COSIA). However, GT-OTSG may not be able to satisfy the steam load for SAGD operations if it is designed primarily for power.

Cenovus: Blowdown Boiler

Blowdown water from boilers, which constitutes about 20 percent of the boiler feed water, is normally disposed of or treated in order to be re-fed to the boiler. This technology allows the blowdown water to be re-boiled with an evaporator without treatment. It converts about 50 percent of the blowdown water into steam for injection thereby reducing the demand for make-up water by about 50 percent (Cenovus). To incorporate this technology, additional expenses for the evaporator and electricity use must be taken into consideration.

[43] Cleaver-Brooks, 2016. Overview of water treatment systems, Online publication at www.cleaver-brooks.com, accessed October 2016.

Table 2.5 summarizes the emerging technologies for steam generation.

Table 2.5: Summary of Steam Generation Technologies

Technology	Brief Description	Economic Factors	Environmental Factors
SQ90TM OTSG design	Based on the use of rifled pipes within the radiant section of the OTSG to produce higher steam quality	-reduced water treatment cost; -2-5% additional capital cost above the traditional OTSG	-reduction in feed water volumes required for a given steam load
Direct Contact Steam Generation	Technology that allows steam to be produced by directly contacting water with a hot gas in order to vaporize it without the need for boiler tubes	-scalability through smaller equipment sizes, greater portability; -ease of separating and capturing CO2, and higher steam production per fuel consumed	-reduction of produced oily water by 52.1%; -reduction of total water-to-oil ratio by about 7.7%; -decrease of energy intensity of SAGD by up to 7.6%; -reduction of GHG emissions and make-up water intake
Solid Oxide Fuel Cells for Cogeneration	Electricity is generated directly by chemically reacting a fuel and oxygen, rather than by combustion	- economics of fuel cells can improve in situations where the heat and power requirements do not change over time; -reducing the operating temperature requirements can significantly improve economics	-at high temperatures fuel-flexible
Forced-Circulation Oil Sands Steam Generators (FC_OSSG)	Combines the features of a typical OTSG with the advantages of drum-boiler which allows it to operate like a drum-type boiler while managed like an OTSG. FC-OSSG is designed for	- ease of operation and maintenance; -maintaining better reliability attributes of drum boilers -additional investment needed for the evaporator unit and pumping requirements	-can operate at lower steam quality; -handles water quality upsets and higher steam loads
Gas-Turbine Once-Through Steam Generator	Produces both electricity and steam for SAGD operations.	-operates more efficiently than other cogeneration configurations	-17% carbon intensity reduction
Blowdown boiler	Allows the blowdown water to be re-boiled with an evaporator without treatment	-additional expenses for evaporator and electricity use have to be taken into consideration	-reducing the demand for make-up water by about 50%

Source: CERI

Reservoir (RES) Segment

Both the SAGD and CSS methods of in situ bitumen extraction rely on the injection of high temperature, high pressure steam into the oil sands reservoir to reduce bitumen's viscosity from typically >100,000 cp to under 10 cp, and thus, mobilize the bitumen to the surface.[44] The major challenges facing these technologies include:

1. High Supply Cost – because of high initial capital outlay and operating costs, in situ-derived bitumen has high supply costs, usually higher than its conventional crude oil counterparts.
2. High Energy Intensity – the nature of the oil sands reservoir and high viscosity of the bitumen in the reservoir make bitumen extraction energy intensive.
3. High GHG Intensity – given that in situ extraction processes have high energy intensity, they consequently generate significant amounts of GHG emissions.
4. High Water Footprint - current in situ extraction processes require the generation and the injection of steam into the reservoir to mobilize bitumen. Usually, an average of 3 volumetric units of steam is required to produce 1 volumetric unit of water (on cold volume equivalent basis).

Major technology options have been identified under the RES segment. The RES segment includes technologies grouped into solvent-based, steam-solvent-based, electromagnetic technologies and others. These technologies, their types of operation, process areas and key performance indicators are tabulated in Table 2.6.

[44] Gates, I.D., Larter, S.R., 2014. Energy efficiency and emissions intensity of SAGD. Fuel 115, 706–713.

Table 2.6: Brief Summary of Technologies Assessed in the RES Segment

Technology	Brief Description	2015 CAPEX for 30,000 bbl/day bitumen capacity	Energy Use Performance Indicators	Direct (fuel use) GHG Emissions
SAGD (RES Base case).	Uses steam for 30,000 bbl/day bitumen production.	C$1,192 Million	SOR of 3 bbl/bbl. 35,910 GJ/day natural gas and 300 kWh/day electricity required.	60.4 $kgCO_2eq./bbl$ from direct natural gas use emissions.
Pure solvent (e.g., Nsolv and Imperial Oil's Cyclic Solvent Process)	Pure condensing solvent is used for bitumen extraction.	SAGD CPF and overall CAPEX reduced by 50% and 30-40%, respectively	75% reduction in SAGD energy intensity. OPEX is similar to that of SAGD base. No bitumen uplift.	75-80% reduction in SAGD direct fuel-derived emissions
Steam-solvent (e.g., SAP/SA-SAGD)	Uses a combination of steam and solvents for bitumen extraction	Additional $C75.6M to the SAGD base case	33-36% SOR Reduction and 35% natural gas use reduction relative to SAGD base. 10.8%-38% bitumen production uplift.	15%-20% emissions reduction relative to the SAGD base
Electromagnetic Heating (e.g. ESEIEH)	Uses electromagnetic heating combined with pure solvents for bitumen extraction	CAPEX similar to pure solvent except additional electromagnetic heating antenna costs of ~ US$8-10 Million per well-pair	Reduces energy intensity of the SAGD base case by 75%. OPEX is $10/bbl (2015 values). No bitumen uplift.	Potential to reduce GHG emissions by 45-59%
Chemical Additive (e.g. steam-surfactant)	Chemicals (e.g., surfactants) are added to steam and the mixture is injected into oil sands reservoirs for bitumen recovery	A CAPEX of C$37,000 per flowing barrel.	Non-energy OPEX of C$5.81/bbl. Energy intensity of the steam-surfactant process is 10-15% less than that of a SAGD.	Potential to reduce GHG emissions by 10-15%.
In situ thermal extraction (e.g. SEGD)	Involves combustion of natural gas and oxygen in a horizontal well, and the heat produced used to generate steam from injected water.	CAPEX is about $30,000-50,000 per flowing barrel.	Potential reduction of natural gas requirements of a traditional SAGD process by 20-30%.	Potential GHG intensity of 0-10 $kgCO_2e/bbl$.

Source: CERI

More details about RES technologies are provided below.

Pure Solvent Processes

Solvent-based technologies use pure solvent as a steam replacement for bitumen extraction from oil sands reservoirs. Examples of this technology are the Nsolv process and Imperial Oil's cyclic solvent process (a $100 million, 3 horizontal well pilot injecting propane solvent). The Nsolv process is assessed here to demonstrate the performance of solvent-based processes.

Nsolv Process

This is a patented solvent-based bitumen extraction process of the Nsolv Corporation. This technology is in the field testing/demonstration stage. From 2003 to 2007, Nsolv was tested in a set of experiments. These tests confirmed the key features of the process such as rapid chamber growth rates, the harmful impact of non-condensable gases, and the enhanced oil quality and uniform disposition of asphaltenes throughout the extracted sand. Nsolv Corporation announced in August 2016 that it had processed well over 100,000 cumulative barrels of partially upgraded oil at its Dover Demonstration Facility. Nsolv claims to have shovel-ready plans to build a 10,000 barrel per day commercial demonstration facility and is in negotiations with major oil producers. The Nsolv process injects a pure, heated solvent (such as propane or butane) vapor into a bitumen reservoir where it condenses, delivering heat to the reservoir and subsequently dissolving the bitumen while leaving high-carbon asphaltenes and heavy metals in situ. The resulting liquid flows by gravity to a production well where it is pumped to a surface facility.

The surface facility separates out the oil and formation water and purifies the solvent for reinjection. Solvent is typically naturally occurring propane or butane. The temperature of operation tends to fall between 40-60^oC and at pressures at or near the original reservoir pressure, allowing for much lower operating pressures than that of SAGD (the Nsolv Dover Demonstration Facility operates at 600 kPag). The technology has a potential for higher oil rates than SAGD; however, the percentage production uplift in comparison to a conventional SAGD process needs to be ascertained. Nsolv published solvent chamber propagation rates of 2.5-3.0 cm per day or up to 3 times those measured with SAGD at the underground test facility.[45]

Higher quality bitumen with 3 percent asphaltenes is produced compared to 16 percent asphaltenes in SAGD oil.[46] Nsolv produced oil is 13-14 degree API gravity (depending on the solvent used) after solvent separation compared to 8 degree API of native bitumen. Thus, diluent requirement for pipeline transportation is reduced by over 50 percent. A physical blend test by Nsolv showed that their partially upgraded oil required 18 percent diluent to achieve pipeline specifications. Nsolv claims that process simplification reduces CPF and overall plant capital costs (see Table 2.6). These estimates include solvent purification units and vaporizers. Due to solvent recovery limitations (about 11.5 percent of the injected solvent is considered to be make-up),

[45] Eichhorn, M., 2016. Observations and Predictions on Field-Scale Solvent Chamber Development. Presented at the World Heavy Oil Congress, Calgary, Alberta, Canada.

[46] Kuhach, J., 2015. Cleaner oil sands production. Presented at the Canadian Heavy Oil Conference, Calgary, Canada.

solvent costs are estimated to be in the C$7.68/bbl bitumen range, assuming solvent to oil ratios of 3 bbl/bbl.

When solvents are considered energy sources, loss of solvents (in reservoirs and in solvent recovery process) increases the energy intensity of the process significantly. A key potential issue with a solvent-based recovery scheme is the amount of solvent that stays in the reservoir (called “hold up”) and must be “topped-up”. In addition, solvent vaporization and purification are required, and can be considered the most energy intensive operations of the Nsolv process. Nsolv reports that its process has potential to reduce energy intensity and direct GHG emissions of the base SAGD process (Table 2.6).

Steam-Solvent Processes

Steam-solvent processes combine the benefits of steam-based SAGD and vapour extraction (VAPEX). In the VAPEX method, a solvent (propane or butane or their mixture with non-condensable gas) is injected into the reservoir to reduce bitumen viscosity and mobilize bitumen. Currently there are at least nine SAGD operations that have recently tested or implemented the steam solvent technology. It has been cited that the base case for future development at the Narrows Lake, Aspen, Cold Lake Expansion project and most likely at Suncor’s Meadow and Lewis developments will use steam-solvent processes. The projects that are using steam-solvent processes include Cenovus Christina Lake (Butane SAP), Cenovus Foster Creek (Butane SAP and condensate SAP), Connacher Great Divide (SAGD+), Conoco Surmont (e-SAGD), Imperial Cold Lake (SA-SAGD-), MEG Christina Lake (eMVAPEX), Nexen Long Lake, Statoil Leismer, and Suncor Mackay. These steam-solvent processes are almost at a commercial stage. Our study focuses on two major steam-solvent processes that are close to commercialization: the Solvent Aided Process (SAP) and the Solvent-Assisted SAGD (SA-SAGD) processes.

SAP Process

SAP is a steam-solvent process of bitumen extraction being developed by Cenovus Energy. A pilot of this process has been implemented at PanCanadian's Senlac Thermal Facility. The SAP method introduces a small amount of hydrocarbon solvents into the steam used for SAGD bitumen recovery and mobilization. Solvent concentration of 10 percent wt. of the steam injection rate seems optimal.[47] It is expected that SAP will result in improved SOR (or reduced energy and GHG intensities) and improved recovery; thus, improved economics.[48]

Reported results show oil rates increased and the SOR experienced a corresponding decrease.[47] For example, energy intensity was reduced by 30 percent (SOR reduction from 2.6 to 1.6 m^3/m^3)

[47] Gupta, S., Gittins, S., Picherack, P., 2002. Field Implementation of Solvent Aided Process, in: PETSOC-2002-299. Petroleum Society of Canada, PETSOC. doi:10.2118/2002-299

[48] Gupta, S., Gittins, S., Benzvi, A., Dragani, J., 2015. Feasibility of Wider Well Spacing With Solvent Aided Process: A Field Test Based Investigation, in: SPE-174411-MS. Society of Petroleum Engineers, SPE. doi:10.2118/174411-MS

with a solvent recovery factor that exceeded 70 percent.[49] Recent results from a single well pair using butane co-injection (10 percent-wt.) show a 31 percent reduction in SOR and a 12 percent increase in oil recovery.[50] The solvent recovery factor was reported to be 64 percent[50] and no significant de-asphalting or partial upgrading is obtained.

The SAP CAPEX is similar to that of the SAGD process but an additional C$63 million (2002 values) would be needed for a 40,000 bbl/day.[47] The additional cost is as a result of modifications of the SAGD facility to allow for solvent storage, treatment, recycle plant, and additional wells. Cenovus Energy had proposed in a suspended project application submitted to the AER to apply SAP in a 45,000 bbl/day Narrows Lake project that would cost C$1,600M (2013 values).[51] For CAPEX calculations, CERI used SAGD Base Case CAPEX and included solvent recovery unit costs.

Gupta et al. (2002)[47] reported an energy intensity reduction from 1 GJ/bbl (6.29 GJ/m^3) to 0.7 GJ/bbl (4.4 GJ/m^3) – a 30 percent reduction, and SOR is reduced from 2.4 to 1.65 m^3/m^3.[47] Reduction in SOR leads to a 15-20 percent reduction in the CO_2 emissions per barrel of oil over a 15-year period.[49] Similar to the pure solvent-based extraction methods, the extent of solvent recovery has a significant impact on the economic and GHG emissions performance of the steam-solvent processes.

SA-SAGD Process

The SA-SAGD process is a steam-solvent process of oil sands bitumen extraction which is being developed and piloted by Imperial Oil at Cold Lake at the Clearwater formation in Alberta. The SA-SAGD technology is ready for full-scale commercial application, and is proposed for Imperial Oil's Cold Lake Expansion Project with its regulatory application and environmental impact assessment (EIA) submitted to the Alberta Energy Regulator. In this process, up to 20 vol.% by volume of hydrocarbon solvent is injected together with 80 vol.% of dry steam in a dual horizontal well SAGD configuration.[52]

Results obtained from the SA-SAGD pilot indicate improvements in oil production rates as well as SOR. Production rates increased from 25-30 m^3/day to 40-75 m^3/day whereas SOR decreased from 5.5 m^3/m^3 to 3-4 m^3/m^3.[52] Solvent recoveries greater than 75 percent can be obtained.

The CAPEX associated with the SA-SAGD is similar to the CSS process but additional CAPEX would be needed for a solvent recycle plant, storage, and additional wells and treatment. A 45,000

[49] Ardali, M., Barrufet, M., Mamora, D.D. and Qiu, F., 2012, January. A critical review of hybrid steam/solvent processes for the recovery of heavy oil and bitumen. In SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.
[50] Gupta, S., Gittins, S., Benzvi, A., Dragani, J., 2015. Feasibility of Wider Well Spacing With Solvent Aided Process: A Field Test Based Investigation, in: SPE-174411-MS. Society of Petroleum Engineers, SPE. doi:10.2118/174411-MS
[51] CanOils, 2015. Oil Sands' project list.
[52] Perlau, D., Jaafar, A.E., Boone, T., Dittaro, L.M., Yerian, J.A., Dickson, J.L. and Wattenbarger, C., 2013, June. Findings from a Solvent-Assisted SAGD Pilot at Cold Lake. In SPE Heavy Oil Conference-Canada. Society of Petroleum Engineers.

bbl/day plant whose application for development in Aspen was submitted to the AER projected a capital cost of C$2,333M (2013 dollars).[53] However, for CAPEX calculations, we used CERI's SAGD Base Case CAPEX and included solvent recovery unit costs.[54]

Loss of solvent, which could be up to 25 percent of injected solvent, is considered a major contributor to OPEX. Though pentanes plus (C$104/bbl in 2011 and C$101/bbl in 2012) was the solvent that was to have been used by Perlau et al. (2013),[52] our calculations used propane (C$22/bbl propane, 2015 values), and assumes no solvent recovery. This is a conservative assumption given that solvent recovery is possible. Reduction in SOR could lead up to a 30 percent reduction of the CO_2 emissions per barrel of oil. Similar issues highlighted for the SAP process which include solvent pricing, solvent retention in the reservoir and low solvent recovery factors are important setbacks to the SA-SAGD process.

Electromagnetic Heating Processes

Electromagnetic (EM) heating processes rely on preferential absorption of EM energy as a means of increasing the temperature of dielectric materials.[55] EM waves exert torques on the polar molecules of water entrained in oil sands. This causes the molecular dipole moments of water to align themselves with the oscillating electric fields of the EM waves. The interactions of oscillating polar molecules with their neighbours take place and generate frictional heat, which raises the temperature of the medium.[55]

In this study, we focus on two processes that are being developed in partnership with some oil sands industry players to illustrate the potential of EM-based technologies. These include enhanced solvent extraction incorporating electromagnetic heating (ESEIEH) and the Radio frequency (RF) XL processes.

ESEIEH Process

The ESEIEH process is being developed by a consortium which includes Harris Corporation, China National Offshore Oil Corporation (CNOOC), Devon and Suncor Energy. Following a successful proof of concept test at Suncor's mine, Suncor and Harris Corporation initiated a pilot of the process at the Dover facility. However, the Climate Change and Emissions Management Corporation (CCEMC) ranked this process as a demonstration project.

The ESEIEH process uses a combination of electricity and solvent to reduce bitumen viscosity to enhance flow-ability. Similar to the SAGD configuration, the ESEIEH process uses horizontal well pairs and a radio frequency (RF) antenna as a heat generation medium. The antenna uses electrical power to produce electromagnetic radiation, which is absorbed by dielectric materials in the oil sands reservoir and consequently heats and mobilizes bitumen. The heat transfer in the

[53] CanOils, 2015. Oil Sands' project list.
[54] Field Implementation of Solvent Aided Process, in: PETSOC-2002-299. Petroleum Society of Canada, PETSOC. doi:10.2118/2002-299
[55] Bera, A. and Babadagli, T., 2015. Status of electromagnetic heating for enhanced heavy oil/bitumen recovery and future prospects: A review. Applied Energy, 151, 206-226.

reservoir is facilitated by the connate water, which is set into vibration when electromagnetically heated. The purpose of adding a solvent in the process is to further reduce viscosity and enhance flow-ability. Here, a radio antenna placed inside injection wells heats up injected fluids and fluids in the surrounding reservoir itself. An example of solvent used is propane or butane.

The ESEIEH process cost is estimated to be at least 120 percent of the conventional SAGD plant cost. Expert opinion suggests a value of up to 200 percent of the conventional SAGD process depending on the number of wells, antenna lifespan and performance. The antennas for RF electromagnetic heating would cost about US$8-10 M per well-pair or US$5-10 M/MW.[56] The OPEX for ESEIEH is $10/bbl (2015 values) which consists of a solvent (propane) cost of $5/bbl and electricity requirement of about 44 kWh/bbl.[57]

The ESEIEH process has the potential to reduce GHG emissions by 45-59 percent.[57] The lower range is achieved using Alberta electric grid (CO_2 intensity of 760 kgCO_2/MWh) whereas the upper end uses cogeneration (CO_2 intensity of 350 kgCO_2/MWh). The ESEIEH process has the ability to reduce energy intensity of the SAGD base case by 75 percent. It reduces SAGD energy intensity from 1.08 GJ/bbl to 0.16 GJ/bbl.[57]

RF XL Process

Radio Frequency XL is a radio frequency (RF) technology which is currently being developed by Acceleware in collaboration with General Electric. RF heating is an emerging technology with the potential to provide an efficient production solution that competes with or enhances traditional steam heating and solvent-based techniques used for producing heavy oil. RF harnesses the energy contained by an EM wave (10 kHz – 100 MHz, corresponding to the RF range), which is indirectly transferred as heat energy to the oil sands reservoir.

The EM heating process directly heats the connate water. Consequently, the heated connate water heats up the oil, therefore reducing bitumen viscosity. Similar to the ESEIEH process, the RF XL process operates through a down-hole deployment of an antenna or applicator which radiates an EM field into an oil-bearing formation.[58] The energy contained in the EM is dissipated into heat and results in an increased temperature of fluids and rocks.

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[56] Koolman, M., Huber, N., Diehl, D. and Wacker, B., 2008, January. Electromagnetic heating method to improve steam assisted gravity drainage. SPE-117481-MS. In: International Thermal Operations and Heavy Oil Symposium. Society of Petroleum Engineers.

[57] Patterson, C., 2016. An Overview of Oil Recovery Using Radio Frequency Heating Technology: The Tools, Techniques and Processes Behind the ESEIEH Hydrocarbon Extraction Process. In: the Heavy Oil Conference, Calgary, Canada.

[58] Vaca, P., Pasalic, D., Okoniewski, M., 2014. The application of radio frequency heating technology for heavy oil and oil sands production. Acceleware Whitepaper: Version 1.0. Available at http://www.acceleware.com/sites/all/pdf/20140604_RF_HEATING_WHITEPAPER.pdf .

The RF XL process has similar cost characteristics with the ESEIEH process. On a per well basis, the antenna cost is about US$8-$10 million per well-pair or US$5-$10 million/MW.[59] Also, solvent costs are estimated to be similar to that of the ESEIEH process. Energy intensity of this process is low. Low SORs can be expected because energy requirements for extracting a unit volume of bitumen from oil sands reservoirs are lower than those required by a traditional SAGD plant.

For example, Vaca et al. (2014)[58] reported an effective SOR of 1.8-2.2 and 1.34 for RF heating with no pressure enhancement and with pressure enhancement, respectively. Application of RF heating process combined with gas injection required 1-2.5 GJ of instantaneous energy to extract 1 m^3 oil against a typical SAGD project which requires an energy/oil ratio of about 9 GJ/m^3.

Others

Some of the technologies that do not fall into the solvent-based or steam-solvent process categories are addressed in this section. These technologies are chemical additive-based or chemically activated in situ combustion methods. Specifically, two technologies are covered, and these are the Steam-surfactant process and the Steam Environmental Generated Drainage (SEGD) process.

Steam-Surfactant Process

The steam-surfactant process is being investigated by several industry players such as Cenovus Energy, Suncor Energy, etc. These processes exhibit similar characteristics in terms of cost, energy and environmental performance. In the steam-surfactant process, surfactants (e.g., petroleum sulfonates) are mixed with other compounds such as alcohol and salt, and added to steam. Surfactants are expensive and are used in minuscule amounts, so alkalis and salts are usually combined with surfactants for better performance and economics. The mixture is then injected into oil sands reservoirs.

Surfactants are amphiphilic organic compounds that contain a hydrophobic group and a hydrophilic group that make them soluble in organic solvents as well as in water. Thus, surfactants reduce interfacial tension and capillary pressure between water and oil, making it easier to sweep both oil and water because of better mixing. A significant reduction of the interfacial tension can reduce the residual oil saturation and increase the oil displacement efficiency and the oil recovery factor.[60]

CAPEX and OPEX reported for the Cenovus Energy steam-surfactant process, which is a typical representation of the steam-surfactant methods, are used in our calculations. A CAPEX of

[59] Koolman, M., Huber, N., Diehl, D. and Wacker, B., 2008, January. Electromagnetic heating method to improve steam assisted gravity drainage. SPE-117481-MS. In: International Thermal Operations and Heavy Oil Symposium. Society of Petroleum Engineers.
[60] Galas, C., Clements, A., Elden, J., Jeje, O., Holst, D., Holst, R. 2013. Identification of enhanced oil recovery potential in Alberta. Phase 2 Final Report for Energy Resources Conservation Board. Sproule Associates Limited, Calgary, Alberta. Available at http://aer.ca/documents/reports/ercb-eor-report2.pdf (accessed January 13, 2017).

C$37,000 per flowing barrel and a C$5.81/bbl non-energy operating costs were reported in the CanOils Project List.[61]

It is expected that the use of water-based solvents mixed with surfactants will increase oil recovery and reduce energy requirements – with minimal associated costs or environmental footprint. Suncor Energy reported that this approach, which was tested at the pilot scale on three well pairs at the MacKay River project in 2013, yielded promising results. The pilot testing has continued on three full pads of mature wells at MacKay River. Injection of surfactants is done in very small proportions (e.g., 0.01-0.1 percent). It is estimated that the energy intensity of the steam-surfactant process is 10-15 percent less than that of a traditional SAGD. More information about this process is presented in the Appendix.

SEGD Process

The SEGD process is an in situ thermal extraction process for oil sands being developed by Valence Energy Corp. The SEGD process involves the combustion of natural gas and oxygen in a horizontal well, and produced heat generates steam from injected water. The generated mixture of steam and hot flue gas from the oxy-combustion of natural gas is used to heat oil sands in the reservoir. Through gravity drainage, the hot oil and steam condensate drains to a lower production well where the hot oil and water are pumped to the surface. Instead of generating steam for in situ bitumen extraction using surface facilities, SEGD generates the steam in the sub-surface.

SEGD is expected to reduce CAPEX of a SAGD base case by about $8,000-$10,000 per flowing barrel. SAGD CAPEX is about $30,000-$50,000/bbl/day but is expected to be lower ($22,000-$42,000 bbl/day) as the technology matures. The SEGD OPEX is expected to be comparable to SAGD.

The SEGD process has the potential to reduce the natural gas requirements of a traditional SAGD process by 20-30 percent and to achieve a GHG intensity of 0-10 kgCO_2e/bbl. The SEGD process utilizes the combustion steam and water in the reservoir. Thus, SEGD will not require significant make up water. It requires about 0.2-0.6 m^3 of makeup water per m^3 of oil. More information about this process is presented in the Appendix.

Upgrading (UPG) Segment

The upgrading section covers partial or full upgrading technologies that are being developed mostly by technology vendors and oil sands industry players. Bitumen extracted from oil sands using any of the commercially viable methods is usually partially or fully upgraded or has added diluent to enhance its flow-ability. The upgrading or diluent addition step helps to reduce the viscosity of the extracted bitumen to pipeline specifications. The practice for most SAGD

[61] CanOils, 2015. Oil Sands' project list.

operators is to ship dilbit, a bitumen-diluent mixture with an approximate 70:30 (bitumen to diluent volumetric) ratio.

Diluent is comprised mainly of natural gas condensates, naphtha or a mix of other light hydrocarbons. The issue with this level of diluent addition is that the diluent takes up 30 percent of the pipeline volume that would have been used to transport bitumen. Thus, pipeline tariff costs are incurred on a volume basis not only for bitumen transport but also for diluent transport. The main challenges addressed in the UPG segment are related to costs associated with partial or full upgrading, and reduction of diluent addition volumes, high energy and GHG intensities.

Upgrading or partial upgrading technologies that are close to market deployment are presented, and the technology's potential to address the above-mentioned challenges are assessed. These technologies use approaches that involve one or a combination of thermal, mechanical and chemical methods. The technologies assessed include Enhanced Jetshear (EJS), Cold Catalytic Cracking (CCC), Desulphurization and Upgrading (DSU), Increased Yields and Qualities (I^YQ), HTL and High Quality (Hi-Q) processes. These technologies, types of operation and key performance indicators are tabulated in Table 2.7.

Table 2.7: Brief Summary of Technologies Assessed in the UPG Segment

Technologies	Brief Description	2015 CAPEX for 30,000 bbl/day bitumen capacity	Energy Use and Performance Indicators	GHG Emissions from Fuel Use and Electricity
Full upgrading (UPG segment benchmark)	Delayed coking upgrading, processing 30,000 bbl/day	C$1,802.3 Million	661 MJ/bbl natural gas and 12 kWh/bbl electricity	132 $kgCO_2$/bbl
EJS	Uses a reactor to strip light ends and pumps resulting in cavitation and mechanical shearing	C$188.3 Million	43.1 MJ/bbl natural gas equivalent and 2 kWh/bbl electricity	3 $kgCO_2$/bbl
CCC	Uses liquid catalyst to convert bitumen to upgraded product or directly to diesel	C$150 Million	C$4/bbl catalyst costs and additional C$1/bbl for natural gas and electricity	20 $kgCO_2$/bbl
DSU	Desulfurizes hydrocarbon feedstocks using sodium metal in addition to hydrotreating	C$511.7 Million	124 MJ/bbl natural gas equivalent, 33 kWh/bbl electricity and operating costs of about $15/bbl	36 $kgCO_2$/bbl
I^YQ	Uses molecular weight reduction and deep conversion in a cross-flow fluidized bed reactor	C$791.7 Million	Energy and operating costs are assumed to be similar to delayed coking upgrading	49 $kgCO_2$/bbl
HTL	Uses high temperature pyrolysis in a circulating sand bed	C$810 Million	Energy intensity reduction of 20% relative to delayed coking. Operating costs are C$2/bbl – C$4.4/bbl	36 $kgCO_2$/bbl
Hi-Q	Uses mild thermal cracking and solvent de-asphalting process	C$900 Million	Operating costs are C$3/bbl – C$4/bbl	57 kgCO2e/bbl

Source: CERI

The assessment aims to determine primarily the ability of the technology to reduce supply costs of bitumen and cut greenhouse gas (GHG) emissions. In order to compute the impact of the technology on the supply cost of oil, capital expenditures (CAPEX) and operating expenditures (OPEX) obtained from the technology vendors, available literature, and expert elicitation are used. More details about UPG technologies are provided below.

Enhanced JetShear (EJS) Process

The EJS is a technology of Fractal Systems Inc. The technology is between the field and launch stages. In 2015, the company announced that it had successfully completed testing of JetShear at its 1,000 bpd commercial demonstration facility with its partner, a major oil sands producer. The facility operated for approximately one-year processing over 100,000 barrels demonstrating long-term reliability. Fractal's EJS technology is a moderately high severity partial-upgrading innovation.

The EJS technology uses a combination of pump and reactor systems to produce a partially upgraded product through stripping of lighter ends, heating to just below thermal cracking temperatures and pumping, consequently causing cavitation and mechanical shearing in a proprietary hammer technology reactor. In addition, the EJS has an olefins removal and low pressure catalytic hydrogen polishing of the naphtha cut which is later blended with the final product. These processes yield higher quality bitumen that requires lower diluent volumes to meet pipeline specifications than the diluent addition process for dilbit production.

Fractal Systems conducted Class 4+ feasibility studies[62] of the EJS facility in 2015. They estimated the economics of the process by assuming the facility is located adjacent to a new or existing SAGD CPF. For an EJS facility processing 51,100 bbl/day, the CAPEX is C$5,460/bbl/day nameplate and C$6,266/bbl/day nameplate for an EJS facility processing 34,100 bbl/day bitumen. The latter CAPEX value is used, being close to the 30,000 bbl capacity basis for our assessments. Operating costs are estimated using energy and non-energy costs. Energy is required or used as heat, hydrogen, flare or electricity.

For a 30,000 bbl/day sized EJS with Acid Reduction Process (ARP) facility, the energy intensity is computed by combining fuel and power requirements:

1. Heater – 41.1 GJ/hr.
2. Hydrogen – 12.1 GJ/hr.
3. Flare – 0.6 GJ/hr., and
4. Operating Power – 4261.4 Kw

These heater, hydrogen and flare energy values are calculated as natural gas equivalents and thereafter natural gas cost is calculated. The power cost is also calculated using power consumption.

The EJS process on its own generates GHG emissions, resulting in an emissions intensity that is equivalent to dilbit if the products are brought to A WTI basis. However, according to a life cycle GHG assessment study carried out by ClimateCHECK in 2016, the EJS process brings some GHG reduction benefits when assessed on a life cycle (wells-to-refinery) basis.

Cold Catalytic Cracking (CCC) Process

The CCC process is an upgrading technology of Bayshore Petroleum. The technology is at field and demonstration stages. The CCC is a process that uses a proprietary liquid catalyst to convert bitumen to upgraded product or directly to diesel. The technology operates at 400-450°C and

[62] Based on a cost classification system applied in engineering, procurement and construction for process industries, a Class 4 or 4+ cost estimate is obtained using an estimating method that factors in costs of equipment and has an expected estimation accuracy of about -30% to +50%.

produces a gaseous stream (mainly methane), diesel and solid coke. The CCC process can also be used for catalytic partial upgrading to convert bitumen to transport-ready bitumen. The partially upgraded product has the following properties: viscosity (143 mPas) and density (0.89 kg/L). Hydrogen is not needed in this process and the process does not require high temperatures and pressures.

The CCC CAPEX is estimated at $8,000 per flowing barrel[63] for bitumen to diesel and $5,000/bbl for partial upgrading. About $4/bbl is the cost associated with the liquid catalyst, about an additional $1/bbl from natural gas and electricity use. Energy and GHG intensity of partial upgrading using the CCC process is calculated at an approximate 30 percent reduction with respect to delayed coking upgrading technology.

Desulphurization and Upgrading (DSU) Process

The DSU process is a technology of Field Upgrading. The technology is currently at a 10 bbl/day pilot scale, while a 2,500 bbl/day demonstration is planned for 2019. In this process, sodium metal (Na), H_2 and hydrocarbon feedstocks are mixed in a continuous stirred tank reactor operating at around 350^{o}C and 750 psig. The DSU process uses different types of feedstocks such as bitumen, heavy oil, vacuum residues, etc. Sulphur in the feedstock reacts with Na (an exothermic reaction that generates heat) to form sodium sulphide (Na_2S), causing hydrogen to replace the double bonds that sulphur previously occupied. As a result, a low sulphur-containing an upgraded oil product with lower viscosity (increased by 8-10 degrees API) is produced.

Heavy metals and the Na_2S are separated from the upgraded product using a centrifuge. The Na metal is recovered from the Na_2S using an electrolytic method. Major energy inputs of the process are hydrogen (needed in small amounts – about one-fifth of what the hydrotreating processes require) and electricity for electrolytic Na recovery. However, the exothermic formation of Na_2S produces the same amount of energy (as heat) output as the electricity input.

Unlike partial upgrading technologies, the oil product from the DSU process is targeted for the bunker fuel market compared to partial upgrading technology companies whose aim is to reduce the amount of diluent added to bitumen to make it pipeline-ready. The bunker fuel has a market size greater than 2 million bbl/day. The market strategy of Field Upgrading stems from an anticipation of an agreement by the International Maritime Organization's Marine Environment Protection Committee to implement the global 0.50 percent sulphur limit by 2020. This agreement was announced in October 2016. The current sulphur standard is 3.5 percent in residual heavy fuel oil products. The 0.5 percent sulphur cap is seen in many quarters to be a challenging goal to realise. However, the DSU's oil product has only 0.1 percent sulphur content.

Using bitumen as a feedstock, the capital cost is estimated at $35,000/bbl/day whereas the capital cost is about $30,000/bbl/day for vacuum residue. The operating costs associated with

[63] Stastny, R.P, 2016. The long and winding road to partial oil sands upgrading in Alberta still has ways to go. JWN Energy, June 3, 2016. Available at http://www.jwnenergy.com/article/2016/6/long-and-winding-road-partial-oilsands-upgrading-alberta-still-has-ways-go/ (accessed January 13, 2017)

the conversion of bitumen to low sulphur, upgraded oil is about $15/bbl whereas the operating costs associated with upgrading vacuum residual oil using the same process is $10/bbl.

The emissions from the process are derived mainly from the H_2 production and electricity generation emissions. The energy requirements of the process include 200 scf H_2/bbl and an electricity requirement of 8 MW for a 10,000 bbl/day plant. Since the cost of elemental Na is about $2,000/tonne there are obvious concerns that the requirements of Na for a process scaled up to several tens of thousands of barrels of bitumen per day will drive up the costs of Na if the Na recovery process is not efficient.

Increased Yields and Qualities (I^YQ) Process

The I^YQ process is an upgrading technology of ETX Systems. I^YQ is registered trademark and an acronym for increased yields and qualities. This technology is a primary upgrading method, which focuses on molecular weight reduction and deep conversion. It uses a cross-flow fluidized bed reactor fluidized by recycled product gas or natural gas. The I^YQ technology vaporizes bitumen in a cross-flow fluidized bed. Natural gas is charged into the bottom of the reactor and the gaseous products of conversion move upwards by the fluidizing gas and are collected at the top of the reactor.

Different fractions of the gaseous products are drawn from the reactor, quenched, separated, and cleaned up. These fractions include a vacuum gas oil (VGO) cut (API gravity of 15.4), a diesel cut (API gravity of 23.2) and a kerosene cut (API gravity of 32.5). Also, for every barrel of bitumen processed, 25 kg of coke is produced. ETX Systems claims that the major benefits of the I^YQ process over the delayed coking process include:

1. a 9 percent higher liquid yield per barrel of raw bitumen, I^YQ produces approximately 0.89 bbls of distillable liquids compared to approximately 0.80 bbl for delayed coking;
2. increase in quality of the oil; and
3. a reduction in the size of the reactor.

For a 60,000 bbl/day processing capacity, a CAPEX savings of $600 M over the delayed coking process is reported. Operating costs of the I^YQ process are estimated to be similar to that of the delayed coking process with utility requirements of $5.5-6.0/bbl range.[64] Disposal of coke is a challenge that this process will deal with and consequently, associated coke transport and landfill costs become significant. Due to the increase in yield, a 10 percent reduction in emissions is expected when compared to delayed coking.

[64] Svrcek, B., Flint, L., Remesat, D., Penner, R., Guo, J. 2016. Partial Upgrading Background Review "White Paper" In Support of The National Partial Upgrading Program (NPUP). A Report prepared by Revamping & Optimising (ROI) Inc for AI-EES. AI-EES Contract #2280.

I^{Y}Q is different from most partial upgrading approaches in that it seeks to both maximize the value of the partially upgraded product through deep conversion as well as eliminate the need for diluent and provide a pipeline ready product.

Heavy to Light (HTL) Process

The HTL process is a heavy oil upgrading technology of the now liquidated Ivanhoe Energy, whose intellectual property rights were purchased by FluidOil. The technology is in the demonstration phase and uses rapid and high temperature (~500ºC) pyrolysis in a circulating sand bed. Using a circulating transport bed of hot sand, heavy feedstock is heated to produce lighter products. The upgraded products are quenched at the exit of the reactor cyclone and routed to the atmospheric distillation unit where distillates and lighter materials are sent to product tank and blended with straight-run oils.[65]

The process can selectively remove metals, salts, water and nitrogen from the feedstock, while maximizing the liquid yield, and minimizing coke and gas production. The extent of upgrading that the process achieves meets pipeline specifications,[66] thus diluent needed for pipeline transportation is eliminated.[67] The technology can be deployed in the upstream, at the well head or integrated into the SAGD operation. This technology is characterized as being in the demonstration stage.[65]

The HTL process is economic at feed capacities of 10,000-150,000 bbl/day and the typical Class 4 cost estimate for the HTL plant ranges from C$27,000-C$42,000 per barrel capacity depending on the capacity. Operating cost is estimated at US$1.8-$3.8/bbl. The process can operate as a net zero natural gas importer given that it can burn lighter hydrocarbon products to be self-sustaining, but it would require 30-35 kWh/bbl electricity.[67] GHG emissions of the process are more than that of dilbit when compared on a WTI basis. However, the GHG emissions intensity is lower than that of SCO.

High Quality (Hi-Q) Process

The Hi-Q process is a partial upgrading technology of MEG Energy. This process is in the demonstration stage with a 3,000 bbl/day unit in construction. The Hi-Q is a mild thermal cracking and solvent de-asphalting process that converts bitumen to asphalt-free, pipeline-ready, heavy oil. The Hi-Q process heats bitumen at high temperatures which consequently generate light oil and a residual fraction. The light oil is collected as upgraded oil whereas the heavy components are routed to the de-asphalter. At the de-asphalter, the feed is used to produce solid asphaltenes and lighter liquids.

[65] Castañeda, L.C., Munoz, J.A. and Ancheyta, J., 2014. Current situation of emerging technologies for upgrading of heavy oils. Catalysis Today, 220, 248-273.
[66] Freel, B., Graham, R.G. 2012. Rapid thermal processing of heavy hydrocarbon feedstocks. US Patent 8,105,482.
[67] Svrcek, B., Flint, L., Remesat, D., Penner, R., Guo, J. 2016. Partial Upgrading Background Review "White Paper" In Support of The National Partial Upgrading Program (NPUP). A Report prepared by Revamping & Optimising (ROI) Inc for AI-EES. AI-EES Contract #2280.

The lighter liquids are combined with the light oil collected at the first stage of the process to produce partially-upgraded bitumen requiring much less diluent than crude bitumen. A combination of mild thermal cracking and solvent de-asphalting processes results in an overall yield of up to 90 percent.[67]

Hi-Q CAPEX is estimated to be about $30,000 bbl per flowing capacity[68] whereas the OPEX is estimated to be $3.0/bbl to $4/bbl. Emissions from this process is about 57 $kgCO_2e$/bbl in addition to bitumen extraction emissions. Hi-Q emissions are reported to be 20 percent lower than the delayed coking upgrading process.[68]

Pipelines and Transport (PT) Segment

In this section, we briefly describe pipeline and transport technologies that enable shipment of produced bitumen or dilbit from the CPF to Hardisty. Transport from Hardisty to terminals in the United States is outside the scope of this study.

Bitumen pipeline and transport have become an issue of national and international interest because of the associated environmental and ecological impacts. Key examples are the rejection of the Keystone XL pipeline by the United States former administration and the opposition to the Energy East pipeline by environmental groups, First Nations and other communities. Major challenges facing the PT sector include:

1) Pipeline leakage – the occurrence of pipeline leakage leads to financial and environmental consequences and public concern
2) Pipeline plugging
3) Pipeline monitoring

Due to the paucity of data, a full economic assessment is not performed but some technologies are presented to give a qualitative view of costs and emissions reduction potentials in this segment. These technologies include: 1) Armadillo, 2) Spectrum XLI, and 3) SmartBall. These technologies are described in detail in the Appendix.

Business Management and Analytics (BM) Segment

Business management and analytics is seen as a formidable accelerator of product and service innovation in many industries. Digitalization is one of such BM areas that has been around for a while but the scale and rate of adoption in the oil and gas sector has been minimal. According to an MIT study,[69] the digital maturity of oil companies is among the lowest at 4.68 on a scale of 1 to 10. The reason is that in previous years of high oil prices, more focused effort was put on productivity than on efficiency. Many pundits now see the digital oil field as a great opportunity

[68] Fellows, G.K., Mansell, R., Schlenker, R., Winter, J. 2017. Public-interest benefit evaluation of partial-upgrading technology. The School of Public Policy Research Papers, University of Calgary, Vol. 10, Issue 1, January 2017.
[69] Kane, G.C., Palmer, D., Phillips, A.N., Kiron, D., Buckley, N, 2015. Strategy, not technology, drives digital transformation. MIT Sloan Management Review and Deloitte University Press, July 2015.

for the industry. A recent survey[70] performed by JuneWarren, General Electric and Accenture revealed that oil companies unanimously agree on the higher return on investment of digital technology than other investment opportunities.

Most of the global companies such as GE, BP, Exxon Mobile, Shell, ConocoPhillips, Total, Statoil, etc., are already active in the digital oil field with some deployments of the technologies in various offshore sites around the world. Oil sands companies are poised to exploit digitalization opportunities to improve economic and environmental performance of their operations. Through the application of sophisticated software and data analysis techniques, operators aim to improve their key performance indicators (KPIs). This requires a combination of technologies, processes, and human resources. Essential ingredients of digitalization include: machine learning, visualization, networking and communication.

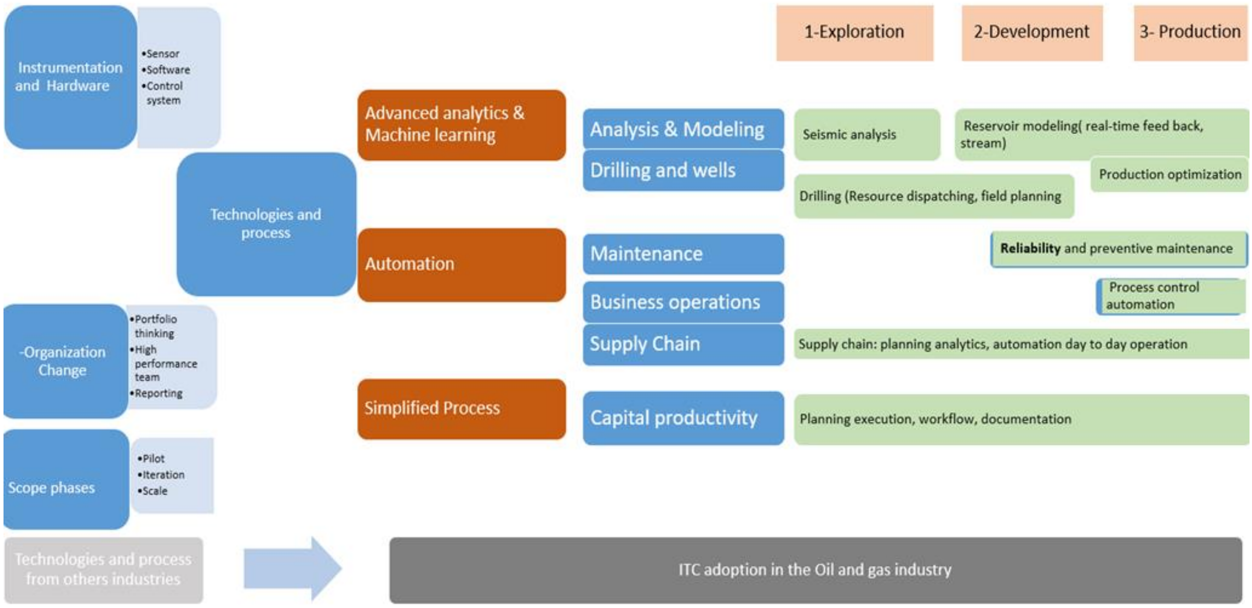
The 2015 BP Technology Outlook[71] sees a 13 percent cost reduction and a 4 percent increase in volume production from 2016 to 2050 due to digital oilfield technology. A recent IHS CERA report[72] observes that digitalization improves productivity by 2 percent to 8 percent, with an operating expense reduction of 5 percent to 25 percent and a capital expenditure reduction from 1 percent to 10 percent (depending on site localization). Concerns about digitalization are the cost of implementation, cyber security and organizational barriers. Figure 2.8 illustrates the opportunity areas for implementing digitalization in the oil sands industry. BM technologies developed by various vendors are presented in the next section.

[70] JWN, 2015. Digital oil field outlook. JuneWarren, October 2015

[71] British Petroleum, 2015. BP Technology Outlook: Technology choices for a secure, affordable and sustainable energy future. Available at http://www.bp.com/content/dam/bp/pdf/technology/bp-technology-outlook.pdf

[72] Edward, T. Adding Value from Digital Oilfield. Available at http://s428994907.websitehome.co.uk/stepchange/wp-content/uploads/2010/05/adding-value-from-digital-oilfield-HP-20102.pdf

Figure 2.8: Adoption and Implementation of Digitalization in the Oil Sands Industry



Sources: CERI, Mckinsey

Business Management and Analytics (BM) Technologies Segment

There are different technology vendors identified under the BM segment. These technologies, their types of operation, process areas and key performance indicators are tabulated in Table 2.8.

Table 2.8: Brief Description of BM Technologies and their Performance

Company	Process Area	Type of Operation	Principal Cost Reduction
OPLII	Inspection and operations management	Connecting fields with the office	40-50% inspection costs
Fotech	Acoustic optic fiber sensor	Well and pipeline integrity	Reduction of OPEX
Tachyus	Steam flood and heat management	Fluid injection and flow optimization	20% reduction of SOR
AER	Digital regulation	Integrated digital repository and process review/risk based request screening	Significant reduction in time for application approval
WireIE	Network service	Mobile high quality network as a service	75% reduction of communication cost
Vista project	Digital engineering environment	Synchronize and shared database for project front end engineering design	16% reduction of front end engineering design
SAS Analytics	Predictive maintenance	Predicting asset failures and reducing downtime	70% downtime reduction
SAS Analytics	Production Optimization	Steam flood injection optimization	7-15% production uplift
SAS SAGD Solution	New technology testing solution	Isolating new technology performance amidst noises	Performance depends on technology

Source: CERI

A more detailed description of the technologies under the BM segment are presented below.

OPLII Calgary

OPLII Calgary is a software company that provides a software-as-service paperless solution, which could reduce inspection costs by 40 percent to 50 percent. This tool is an operations and asset integrity management platform. OPLII extends into remote offline areas, allowing field users to conduct inspections, log work orders and administer projects via smartphone or tablet. This OPLII technology enables operators to take control of sites, facilities, equipment, inspections, work orders, projects, HSE, maintenance and much more – all under the same roof. Functionality includes dashboard KPIs, easy material transfers and powerful quick-searching capability.

WireIE

WireIE is a company that offers a communications network with low latency and high availability. The network is applicable at any stage of a project. At the drilling exploration phase, WireIE can perform complete logistics needed for exploration, operation, shut down and installation of the network from site to site. The company achieves this by offering three options that best fit the needed evolution of the life cycle of a project. These options include fiber backhaul, fixed access modular, and fixed nomadic for drill site.

During the production phase, WireIE can also offer a communications spectrum, IP video surveillance, and real-time telemetry. The company estimates 75 percent reduction in cost of communication from logistics, increased reliability compared to alternative options such as satellite and the LTE system. It also improves communication quality with only 50 percent of the cost of a fiber quality connection. It increases the data quality and safety, creating an opportunity to collect data more broadly from the different systems which is a critical step for any digital oil strategy.

Tachyus

Tachyus is a software company based in California providing software as service "SAAS" for steam flood optimization in oil production. It creates value by leveraging *Data Physics*™, which it developed for processing data using the speed of data science and machine learning techniques, coupled with the physical laws and equations that govern reservoir behavior and well performance, as used in traditional reservoir simulation workflows. *Data Physics*™ is used for real time closed loop reservoir management and cash flow optimization by describing, predicting and prescribing the quantity and placement of injectant fluids required for optimum operations.

The company has a set of applications that optimize fluid injection and cash flow. The most advanced with respect to commercial application in heavy oil are *Atmion* and *Thermion*, with an existing client base in California. *Atmion* and *Thermion* are applicable for thermal oil sands in situ extraction and heat management.

Atmion and *Thermion* are best plugged into mature, brownfield projects with high well count and large quantities of data, or greenfield with 2-3 years' operation data. It depends on how frequently data are collected. Together, the software solutions have helped operators realize an average SOR reduction of 20 percent and/or an average cost reduction of 40 percent and offer streamlined surveillance for engineers to drive decision-making.

SAS Analytics

SAS is an analytics, business intelligence, and data management company with a track record in other industries such as automotive, banking, energy, and utilities. SAS software is used for analytics, business intelligence, and data management. Its oil sands in-situ extraction focus areas are in asset performance analytics, production optimization, and new field technologies integration assessment.

Both steam generation plant and reservoirs generate a large volume of physics data (temperature, pressure, fluid dynamics, etc.). The model documents this massive data set to extract information needed to send an optimal volume of steam in the reservoir. A complex model applying multivariate, random forest analysis between sub-cool temperature and wellhead pressure is used as a proxy to establish a reservoir production profile. The model is adjusted as reservoir conditions change and for each well. The solution, which is scalable and requires no programming skills, can be an asset to bridge the existing digital knowledge gap in the industry.

SAS claims to have achieved a production increase of about 7 percent to 17 percent in an ongoing project in Alberta. The company is also exploring predictive asset maintenance opportunities for monitoring asset performance and predicting failures before they occur. SAS is said to be able to predict a sub-cool event 21 hours in advance – thus, reducing plant downtime and maintenance costs through efficient planning and scheduling.

To implement this technology at a SAGD facility, SAS collects and analyzes operational data to make recommendations on how to improve performance. As with the other data analytics technologies, field demonstrations must be used to establish the specific performance metrics of each deployment.

Fotech

Fotech is a UK-based company with offices in Canada and the US. It develops a Distributed Acoustic Sensor (DAS) for oil and gas wells and pipelines. DAS uses optic fiber and relies on a small variation of light in the refractive index in the fiber. There is a spectrum of backscattered mechanism such as Rayleigh, Brillouin that are used in distributed sensing.

Fotech proposes two applications to oil industry well integrity and pipeline integrity management.

In terms of well integrity, an optic fiber is placed in the well and provides a continuous acoustic profile. The optic fibre can detect casing breaches, tube and bypass leaking and cement casing fractures. The primary output of this technology is a real-time intelligence of the well and downhole tools. It also informs the operation team where production is coming from and the need for concentrating the steam injection effort in the most productive area. Also, it prevents and reacts in real-time to sand inflow and leak detection, limits downtime and updates reservoir seismic data.

For pipeline integrity management, an optic fiber coupled with acoustic sensors is buried along the pipeline to detect any movement, transform it into data and to transmit the data to the pipeline monitoring team. The pipeline application helps to prevent intrusion, leak detection, sound of fluids propagation and warming. It is also used in the pig tracking during pipeline inspection and cleaning.

When deployed for pipeline inspection, the automated system sends a message directly to the infrastructure monitor about an intrusion or any digging around the pipeline. The optic fiber has a life span of 10 to 20 years and can resist high temperatures (300^{o}C) and hydrogenation, and can provide a constant data stream.

Vista Projects

Vista Projects, an Engineering Procurement and Construction (EPC) company, has recently promoted the value add of digitalization in the early stages of a project through their integrated data portal and dashboard called Aveva Net. The portal offers a project database that can be shared by all parties involved in the project execution with real-time updating features.

The expected capital cost reduction reported by Vista Projects is 20 percent relative to the best-executed CPF projects without integrated procurement and construction. This reduction comes from minimizing handover costs, compressing the schedule and improving project execution. The engineering team delivers significant efficiency improvements by:

1. Simplifying the process: All the stakeholders have access to the information they need, and any modification or adjustment is directly updated to the database. The Aveva database is said to synchronize in a manner that enhances information exchange rather than mere flow of emails, spreadsheets, and design patterns.
2. Electronic squad checks: Typically, project reviews required sequential approvals by the teams involved, including engineering, construction, fabrications, and electrical teams. Aveva allows this to be done simultaneously as everyone can access all information on a real-time basis through the shared platform. This could reduce the reviewing hours by about 40 percent. Any required changes to the project can be generated automatically in an updated 3D design that would be ready for implementation.
3. Data-centric progress tracking and digital approvals: Any progress is updated in the shared platform and this helps all stakeholders to align their workflow appropriately.

Vista projects also sees a likely improvement on the environmental performance (relative to a typical SAGD project) of a project if much of the hard-copied documentation can be avoided. While using less paper is always a nice achievement to target, the more substantial cost savings of a digital execution model stem from the potential to minimize construction delays, shorten the project schedule and reduce handover costs. The Aveva platform is said to achieve about 10 percent reduction of total installed cost and 15 percent to 40 percent reduction of engineering cost.

Alberta Energy Regulator Innovation and Efficiency Improvement

The Alberta Energy Regulator (AER) is simplifying procedures and increasing transparency by proposing digital platforms such as Digital Data Submission (DDS), Environmental Site Assessment Repository (ESAR) and reclamation platforms. Their new application process review and integrated application are two innovations which reduce regulatory cost for oil companies and internal workflow within the AER and third-party stakeholders.

Implementation of the new application review process has led to a significant reduction in processing times. The improvements recorded in the Oil Sands Conservation Act under Directive 078 for new and amended commercial schemes are as follows:

- Scheme amend category 1: 21 business days BAU now 10 business days
- Scheme amend category 2: 226 business days BAU now 3 to 6 months
- Scheme amend category 3: 750 business days BAU now within 1 year.

The time reduction comes from simplification and streamlining of risk assessment requirements. The AER also implements an integrated application process for a project by accepting wells, CPF, storm water ponds, pipelines, roads, and land access applications at the same time and in the same form. This reduces the entire application process from 7 years to about 1 year. According to Suncor Energy, the reduction in the application process alone is expected to save about $64 million over the life cycle (25 to 40 years) of its 80,000 barrels per day project at Meadow Creek in Northern Alberta.

There are also cases where technology innovations have spurred regulation change. The development of high fidelity Multiphase Flow Meters (MPFM) which allow simultaneous measurements of the various phases of inflow or outflow of fluids, during development and production from a well, have resulted in more flexible regulatory requirements which are acceptable to all stakeholders. Two such MPFM technologies are the EGAR-50 and Schlumberger VX meter.

Schlumberger describes the VX Spectra surface multiphase flowmeter as using an advanced full-gamma spectroscopy to accurately capture multiphase flow dynamics while enabling real-time data monitoring and analysis – thus, helping to make better-informed decisions and to maximize reservoir productivity. The MPFM can meter gas, water, and oil with an accuracy of +/- 2 percent. The new regulation, driven by the MPFM, is estimated to significantly reduce costs linked to reporting by reducing the number of meters needed (which is normally one for each fluid phase).

Wells and Well Pads (WWP) Segment

Drilling in viscous sand and carbonate present unique challenges because the oil is poorly consolidated, sticks to drilling materials, increasing the cost and delaying the completion of the well. During the past ten years, new solutions such as fluid drilling (Halliburton N-solate Packer Fluid System) were used to tackle these challenges resulting in improved efficiency of the drilling operations.

Although bottom line drilling time (time allocated to deepening the hole count from 35 percent to 50 percent of the total) is optimized, a flat and non-productive time falls out of the control of drilling companies and increases the cost of drilling.

Rather than looking at technologies delivering incremental efficiencies, this study will target the organizational change inspired by other industries that offer higher efficiencies and reduces the cost of drilling.

This section focuses on how lean manufacturing principles apply to drilling operations, and how the modularization of well pads is a viable option to reduce costs in a low oil price environment.

Lean Manufacturing to Lean Drilling

The core idea of lean manufacturing is to maximize customer value while minimizing waste. Lean drilling is being considered as a promising way to reduce cost and delays from drilling. However, lean drilling was applied during BP's Andrew project in 1964, but did not receive traction as in other industries.[73] Drilling process improvement can be achieved through the following avenues:

- Well completion time reduction;
- Tracking efficiency improvement by identifying relevant Key Performance Indicators (KPIs);
- Identifying the variabilities arising from process, equipment, and geology.

Implementing lean strategies can address sources of waste during drilling in order to reduce well time. Process organization tools within Lean, such as Pareto diagram, Total Productive Maintenance, 5S, Mistake Proofing (Poka Yoke), are among the tools to reduce waste, identify improvement opportunities, apply the needed change, and measure their impacts.

Modularization

During the years of fast growth in the oil sands, the industry faced labour scarcity, delays in project schedules, and cost escalation. A study by the Construction Industry Institute (CII) found that projects in Alberta were likely to cost over five times the capital expenditure and took almost twice the time needed to complete a similar project in the US.[74] Modularization was encouraged as an avenue to address this challenge. Although modularization can be used in all the segments of a facility, it seems to hold significant benefit for the well pad segment from cost reduction by standardization and customization of designs to specific geologies. Below, we present some technologies that come as modular designs.

Different technologies and vendors identified under the WWP segment, their types of operation, process areas and key performance indicators are tabulated in Table 2.9.

[73] de Wardt, J.P., 1994. Lean Drilling-introducing the application of automotive lean manufacturing techniques to well construction. In SPE/IADC Drilling Conference, 1994, January. Society of Petroleum Engineers.

[74] COAA and Alberta Energy, 2009. The Alberta Report: COAA Major Projects Benchmarking Summary. Research Contract UTA05-782. Available at https://www.construction-institute.org/nextgen/publications/COAA/COAA_Alberta_Report.pdf

Table 2.9: Brief Description of WWP Technologies and their Performance

Company	Process Area	Type of Operation Performed	Principal Cost Reduction Achieved
Various service providers	Drilling operation management	Lean drilling	Shortening time to complete well and reduce waste
Integrated Thermal Solution (iTS)	Standardization & Modularization	Manufactures wellpad service packages	20-50% CAPEX and time reduction
Wood Group	Standardization & Modularization	Simplified design	40%-50% CAPEX reduction

Source: CERI

A more detailed description of the technologies under the WWP segment is presented below.

Integrated Thermal Solution

Integrated Thermal Solutions Ltd. (iTS) offers a suite of standardized turn-key products and solutions for thermal heavy oil central processing facilities, pipelines, and well pads. The particular product of interest is called the Well Pad Manufactured Solution (WPMS). WPMS integrates reservoir, drilling, completion, surface facility, and operational planning into a single service package. Potential benefits of this technology through schedule enhancement, uncompromised safety, and improved quality via product standardization has been estimated as:

- Field construction reduction up to 20 percent of well pad cost
- 30 percent reduction in overall well pad delivery costs (earth works, D&C facilities)
- 50 percent reduction in well pad delivery lead time
- 300 percent increase in drainage box coverage from a single well pad

Wood Group Standard Well Design (Well 2.0)

Wood Group Mustang, an engineering, procurement and construction management company (EPCM), has presented a standard well pad design which uses a 10-meter spaced drilling pattern with the production wells and steam injection wells arranged in two parallel rows. Electric submersible pumps provide the mechanical lift for the production wells. Cost reduction comes from less material use and simplified design. The design promises to reduce costs from about $4-$6 million to $2.4 million per well pad.

Chapter 3: Study Approach

In this chapter, the framework for this study is described. The data sources, study assumptions and methodology are presented.

Data Sources

This study is data-driven, and the type of information available and accessible are critical in choosing the methods used in assessing the technologies. Since the technologies are grouped into different segments across the in-situ production process and their cost and environmental reduction potentials compared, it is important to employ an objective and consistent basis for comparison.

In all cases, the information available must be adequate and the choice reasonable enough to make an "apples to apples" comparison. Where sufficient data is not available, reasonable assumptions are made and those are clearly stated in the report. Data used in this study are thoroughly analyzed, cross-checked and validated.

Different methods of data gathering were used. These include the following:

- Publicly available data in the form of study reports, conference and journal papers, websites, government documents and patents, etc.
- Expert elicitation through interviews. We consulted oil and gas industry professionals through one-on-one interviews and quantitative surveys to understand the key technologies, their level of progress and challenges.
- Surveys. A sample survey administered to participants is included in the Appendix.

Methodology and Assumptions

Several assumptions were made in this study, some are general, affecting the entire life cycle process, whereas others affect only one or more process segments. The assumptions made are briefly covered in this section. Further details are provided in the Appendix.

Bitumen Extraction: SAGD Base Case

A conventional SAGD process is used as a benchmark for the process. We assume a base case which is modeled after the conventional SAGD in a recent study by PTAC.[75] The SAGD base case uses a mechanical lift system powered by electric submersible pumps. The reservoir is a relatively oil-rich type in the Athabasca region of Alberta, Canada, with an SOR of 3.25 m^3/m^3 (cold water equivalents), and a gas-to-oil (GOR) ratio of 8. The reservoir pressure is assumed to be 3,000 kPag. Similar reservoir characteristics are assumed in this study, with the exception of the SOR, which is adjusted to 3.0 m^3/m^3. This is consistent with CERI's production forecasting model.

[75] PTAC, 2012. Assessment of Innovative Applications of Electricity for Oil Sands Development. JACOBS Consultancy, Available at www.ptac.org/attachments/1425/download

We also assume that no emulsion flashing takes place at the well pad through to the central processing facility. This is because flashing is eliminated by raising the well pad discharge pressure to 4,800 kPag – a step that reduces heat loss from the well and maximizes process energy efficiency.

Diluent Addition

For comparative purposes, the base process, which is a conventional SAGD process is assumed to produce bitumen, a product that is converted to dilbit by adding diluent to SCO by upgrading. The dilbit mixture contains produced bitumen with diluent (natural gas condensates and light hydrocarbons) in a 70:30 (bitumen to diluent volumetric) ratio. The dilbit meets pipeline specifications: 20-22 API gravity, 3-3.6 wt.-% sulfur [76] and <350 centistoke viscosity. This is an important assumption given the predominant industry practice – most SAGD-derived bitumen produced from Alberta is sold as dilbit. Diluent is assumed to be transported to the field where dilution takes place. The diluent price is assumed to be equivalent to the WTI price (C$52/bbl) at Edmonton whereas the diluent pipeline transport tariff from the supply source to the oil sands processing field is estimated at C$0.3/bbl of bitumen.

Partial and Full Upgrading

A number of partial and full upgrading technologies are assessed herein. These technologies are developed as alternatives to diluent addition. While it is instructive to assess these technologies using dilbit economic and environmental performance as a benchmark, it is also deemed important to compare the performance of new partial upgrading technologies using a conventional upgrading technology as a basis. Thus, we used delayed coking bitumen upgrading to synthetic crude oil (SCO) as a yardstick. This is because some of the new and emerging technologies in this area are aimed to achieve deep conversion and, thus, preclude the use of diluent. The products from the partial upgrading and deep conversion technologies vary in chemical and physical characteristics and economic value. For this reason, a WTI equivalent basis was another criterion used to benchmark the economic and GHG emissions performance of the technologies.

Capital and Operating Costs

Capital and labour costs which were relatively high prior to the onset of the recession (in 2014) have experienced some reductions. This led CERI to revise its existing cost assumptions in our 2016 Oil Sands Supply Costs and Development Projects (2016-2036) report. A 14-29 percent reduction in the capital costs for oil sands projects reported in a recent CanOils' report[77] corroborates this fact.

[76] CEPA, 2011. Pipeline Transportation of Diluted Bitumen from the Canadian Oil Sands. Canadian Energy Pipeline Association.

[77] CanOils, 2016. CanOils' Producers Benchmark Report, May 2016. Available at http://www2.jwnenergy.com/summaryproducerbenchmarkstudy

Capital costs are calculated based on the most recent projects (2013-2015) and the closest upcoming ones (2016-2019). This gives an average capital cost of C$39,760 per flowing barrel (C$/bbl/day) or a total installed cost of C$1,192M for a 30,000 bbl/day capacity. The supply cost of the SAGD base plant is calculated to be $43.31/bbl and the capital cost component is $19.65. The capital cost component is 16 percent lower than that reported in CERI Study 152.[78] This is consistent with what was reported by CanOils.[79]

It is also assumed that the facility is operated at 90 percent utilization (assuming one month downtime). When necessary, the six-tenths rule[80] was used for equipment or plant capacity scale-up or scale-down. Using the Nelson-Farrar cost indices for refinery construction, the dollar values reported for different years are converted to 2015 dollar values. The cost indices account for industry's inflationary or deflationary pressures on costs. Where applicable, all cost information in this assessment is brought to 2015 real Canadian dollars, with 2015 as a base year. Unless specifically stated, the dollar values are provided in Canadian currency (C$) and amounts in US dollars (US$) are converted to Canadian dollars using the Bank of Canada conversion rate of C$1/US$0.85.

Table 3.1: 2016 Field Gate Bitumen and SCO Supply Costs

Item	Bitumen at the Field Gate	Dilbit at Field	SCO from Upgraded Bitumen at Field
	C$/bbl	C$/bbl	C$/bbl
Fixed Capital (initial & Sustaining)	19.25	19.25	34.43
Operating Working Capital	0.40	0.40	0.49
Fuel (Natural Gas)	5.87	5.87	11.35
Other Operating Costs (incl. Elec.)	7.54	7.54	8.73
Royalties	7.14	7.14	0.04
Income Taxes	2.82	2.82	8.27
Emissions Compliance Costs	0.27	0.27	2.52
Abandonment Cost	0.03	0.03	0.61
Diluent cost		10.6	
Total Supply Costs	**43.31**	53.9	**66.44**

Source: CERI

78 Millington, D. and Murillo, C.A., 2017. Canadian oil sands supply costs and development projects (2015-2035). Canadian Energy Research Institute (CERI) Study No. 152. August, 2015. Available online at http://resources.ceri.ca/PDF/Pubs/Studies/Study_152_Full_Report.pdf

79 CanOils, 2016. CanOils' Producers Benchmark Report, May 2016. Available at http://www2.jwnenergy.com/summaryproducerbenchmarkstudy

80 Peters, M.S., Timmerhaus, K.D., West, R.E., Timmerhaus, K. and West, R., 1968. Plant design and economics for chemical engineers (Vol. 4). New York: McGraw-Hill.

The operating costs were divided into fixed and variable expenditures. The variable costs account for energy (natural gas, electricity, chemicals, etc.). In Table 3.1, the supply cost of bitumen extracted from the SAGD base case and that of the SCO from upgraded bitumen from the same process are presented. The detailed breakdown of the CAPEX and OPEX of the SAGD base as well as the Upgrader (Delayed Coker) can be found in the Appendix.

The capital costs, which were listed under *Drilling and Production*, *Core Facility, Offsite Equipment*, *Home Office and Engineering Services,* and *Owner's Costs* in PTAC's (2012) report were split between the process segments:

1. Water and Waste Treatment
2. Steam Generation
3. Wells and Well Pads
4. Reservoir
5. Upgrading
6. Pipelines, Storage and Transport
7. Business Management and Data Analytics

Indirect costs related to different segments were proportionally weighted according to CAPEX amounts.

Similarly, full upgrading is modelled after the delayed coking base case presented in PTAC (2012). For processing of 30,000 bbl/day bitumen, a CAPEX of C$1,802.3 million is required. For more detailed cost information, refer to the Appendix.

The supply cost of bitumen is the minimum constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes and earn a specified return on investment.[81] Our economic model assumes a 3-year construction period starting in 2015, a 30-year lifespan and a 10 percent real discount rate for SAGD, partial and full upgrading plants.

Technology Assessment

Most of the operational assumptions and costing are provided by new technology developers and vendors. However, some adjustments are made to fit the basis for our economic and environmental assessments. Data is also collected through secondary sources: available literature and expert elicitation.

Specific methods and assumptions are made for some technologies and processes.

Water Treatment Technologies

Water treatment processes are considered to operate under steady state conditions – constant throughput. Warm lime softening is assumed as a base case for waste and water treatment

[81] AER, ST98: Supply Cost. Available at https://www.aer.ca/data-and-publications/statistical-reports/supply-cost

whereas other technologies are considered as its alternatives. Evaporator technologies are powered by electricity.

Steam Generation Technologies

Natural gas-fueled OTSGs are used as a benchmark for steam generation and 80 percent efficiency is assumed. Injected steam quality is taken to be 100 percent.

Reservoir Technologies

Solvent purification units and vaporizers are required, and CAPEX and OPEX are accounted for in solvent and steam-solvent based processes. However, solvent trucking costs are excluded. Both SOR reduction and production uplifts from steam-steam processes are included in the analysis. Electromagnetic heating processes assume 42 well pairs and antenna lifespan of between 15 and 30 years.

Upgrading Technologies

For all upgrading processes assessed, the emissions and supply cost calculations include those of SAGD bitumen extraction and partial/full upgrading. Though some of the technologies can process different raw materials (coal, coke, biomass, etc.), our analysis focused only on SAGD bitumen as the input material. The boundary is wells to Edmonton/Hardisty (transport of product from field to terminal included). Partial or full upgrading plants are considered to be sited in close proximity to the SAGD plant, thus no pipeline cost is considered for transporting bitumen from field to an upgrading plant.

Partially or fully upgraded products of bitumen are brought to WTI equivalent quality, and where necessary, premiums or discounts are applied for higher or lower value products, respectively. This is done to benchmark and compare the different partial/full upgrading technologies with different processes, products, economic and emissions characteristics. The supply cost is calculated by blending with an amount of diluent necessary to produce a WTI equivalent product with 32 degrees API gravity. For example, dilution of SAGD bitumen (8 degrees API gravity) to a WTI equivalent product requires about 50.6% vol. of diluent for every barrel, with the rest being bitumen. Similarly, partial upgrading technologies are adding diluent to reach WTI-equivalent. On the other hand, synthetic crude oil from the delayed coker does not need dilution because it was assumed to be equivalent to WTI.

Benchmarking the partial/full upgrading products against the WTI quality may not be appropriate for some of the upgrading technologies whose products are not intended as a petroleum refining feedstock. An example of such technology is the DSU. The DSU product is a low sulfur diesel purposed for marine fuel. Thus, diluent addition does not necessarily apply here. However, for the purpose of this normalization of the different upgrading technologies, the WTI benchmark is used.

Business Management and Data Analytics

Cost reductions associated with Data and Business Management applies mostly to the OPEX. Software as services is the primary method for technology deployment in this segment.

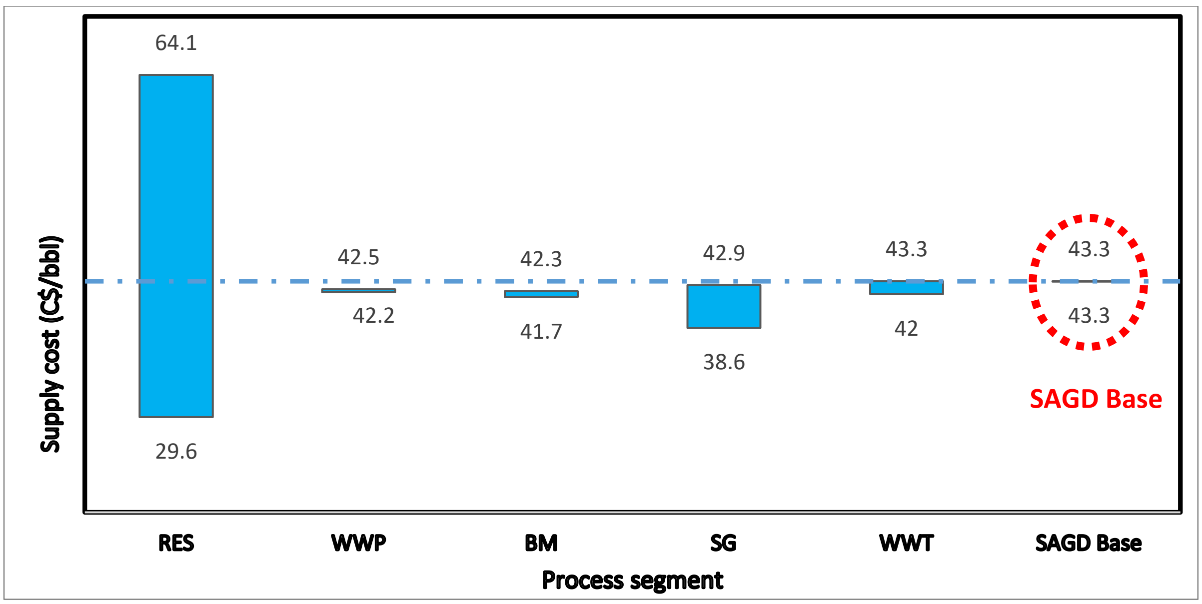
Chapter 4: Results

Bitumen Supply Costs

The economics and emissions reduction potentials of various technologies in each segment are assessed and the results are presented in this Chapter.

For bitumen production supply costs, CERI's supply cost model is used to evaluate the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes as well as earn a 12 percent nominal (10 percent real, with 2 percent inflation rate) return on investment. The supply cost assessed here is the constant 2015 bitumen price (at the field gate) in Canadian dollars per barrel (C$/bbl) that gives a net present value of zero (using a real discount rate of 10 percent) at the end of life of an *in situ* bitumen extraction project (assumed to be 30 years). This excludes diluent addition, upgrading or transportation costs.

Figure 4.1: Range of Supply Costs for Various Bitumen Extraction Process Segments



Source: CERI

The range of bitumen supply costs associated with oil sands technologies, described under RES, WWP, BM, SG and WWT segments, which are likely to be commercial in 5-7 years are shown in Figure 4.1. From the range plot (Figure 4.1), the supply costs from each segment are compared with that of the SAGD Base. From the values, the potential supply cost reductions can be deduced. The blue horizontal dashed line in Figure 4.1 aligns with C$43.3/bbl, which is the bitumen supply cost of the SAGD Base.

The SAGD Base uses OTSGs for steam generation (with 80 percent efficiency), injects high pressure steam (12 barg, steam quality of 100 percent) into an oil sands reservoir, and uses free water knock-out and mechanical treaters for oil treating, and lime warm softening for water treatment. In addition, the SAGD Base has a cumulative SOR of 3 m^3/m^3.

The results shown in Figure 4.1 are obtained by applying emerging technologies in the segment assessed but keeping other process segments consistent with the SAGD Base technology design and make-up. However, in cases where other segments are altered by the application of a new technology, changes are made accordingly to the affected areas. For example, the application of the Pure Solvent technologies, particularly the Nsolv process in the RES segment, leads to a 50 percent reduction of the CPF. This is because water treatment and steam generation facilities are almost eliminated. New equipment for heating solvent to about 60^{o}C will replace steam generation equipment, and since only produced water needs to be treated, the magnitude of water treatment facilities required is dramatically reduced.

RES technologies have the most significant impact on bitumen supply cost reduction, with a potential reduction of 32 percent relative to the SAGD Base. The RES technology with the lowest bitumen supply costs is the steam-solvent process (greenfield development), with potential cost reductions ranging from C$0.50/bbl to C$13.70/bbl.

The magnitude of bitumen production uplift arising from the application of the steam-solvent process is a major contributor to the supply cost reduction. There is a high degree of variability in production uplift (10.8 percent-38 percent relative to SAGD Base) whereas the reported improvements on instantaneous SOR do not vary significantly. Thus, a production uplift of 10.8 percent-38 percent and an SOR improvement of 35 percent are used.

A best case of the steam-solvent process has a supply cost of C$29.60/bbl when a bitumen production uplift of 38 percent is assumed. A worst case of C$42.40/bbl is obtained with 10.8 percent production uplift. The results show that for a greenfield development to be more profitable than the SAGD Base, the steam-solven*t* process must have a production uplift of about 9 percent relative to the SAGD Base.

The steam-solvent process is suitable for both brownfield and greenfield developments. Its application in brownfield developments results in a bitumen supply cost of C$38.10/bbl–$45.40/bbl. The lower and upper ranges represent steam-solvent process with production uplifts of 38 percent and 10.8 percent, respectively. Therefore, for a brownfield development to have supply costs lower than that of the SAGD Base, the steam-solvent process must have a production uplift of more than 19 percent. Another *RES* technology that is also suitable for application in brown and greenfield developments is the steam surfactant process. The results show that this process has the potential to reduce bitumen supply costs of the SAGD Base by about 3 percent.

On the other hand, some RES technologies are applicable to only greenfield developments. Examples of these are the *pure solvent* and the *electromagnetic heating* technologies. The pure solvent processes have the potential to reduce bitumen supply costs by C$3.40/bbl, which is an 8 percent reduction in bitumen supply costs relative to SAGD Base. However, oil from this process is a partially upgraded bitumen with an API gravity of 13-14 against an API gravity of 8 for raw bitumen.

A bitumen product with higher quality, lower viscosity than raw bitumen means that lower amounts of dilution with diluents are required to meet pipeline transport specifications. Therefore, the results show that about C$4/bbl diluent cost can be avoided by using of the *pure solvent* method. This is significant given other benefits are realized alongside diluent cost reduction. These include reduction of pipeline volumes that would have been occupied by diluent, the possibility of a higher price of the product and higher downstream conversions.

However, some RES technologies, specifically the *electromagnetic heating* processes are more cost-intensive than other alternatives, and will not be commercial in a low oil price environment. The bitumen supply cost of *electromagnetic heating* processes is C$60 - C$64 per barrel. The high supply costs from the *electromagnetic heating* process is due to its high CAPEX and OPEX. Major contributors to these costs are high costs of heating electromagnetic antenna costs, disproportionately higher electricity requirements than other technologies and solvent make-up costs. For example, project sustaining costs are increased significantly if heating antennas must be changed mid-life of the project.

Given that some of the reservoir technologies partially upgrade bitumen, when the quality of the bitumen product is accounted for by bringing the product to a Western Canadian Select equivalent (WCS eq.) basis, a greater reduction in supply costs is possible. Relative to the SAGD Base WCS eq. supply cost at Hardisty which is calculated to be C$55/bbl, supply cost reductions obtained are -1 percent to -16 percent for steam-solvent, -14 percent for pure solvent, +27 percent to +30 percent for electromagnetic heating and -8 percent for chemical/surfactant treatmen*t* technologies.

It can be observed that the technologies most favoured by product quality improvements are those using significant amounts of solvents, such as the pure solvent and electromagnetic heating processes, and the chemical/surfactant methods.

The SG segment has the second highest potential to reduce bitumen supply cost. It can reduce the supply costs by 1 percent-11 percent relative to the SAGD Base. The major technology driver for the highest cost reduction under this segment is the use of solid oxide fuel cells (SOFCs) for cogeneration of steam and electricity. SOFCs generate energy directly by chemically reacting a fuel and oxygen, rather than by combustion; thus, SOFCs have a high efficiency. Typical SOFC combined heat and power efficiency can reach 80 percent at an operating temperature of about 1,000^{o}C.

Though the SOFCs technology looks most promising among the SG technologies, application for in situ oil sands extraction applications, it is likely to face significant technical and economic hurdles. Some of the identified setbacks include:

1) Generation of large amounts of electricity that must be sold to the grid

2) Industry-wide deployment of SOFCs will require large investments in new power transmission infrastructure, and
3) Technical issues associated with SOFCs durability and operation at temperatures lower than 1,000°C.

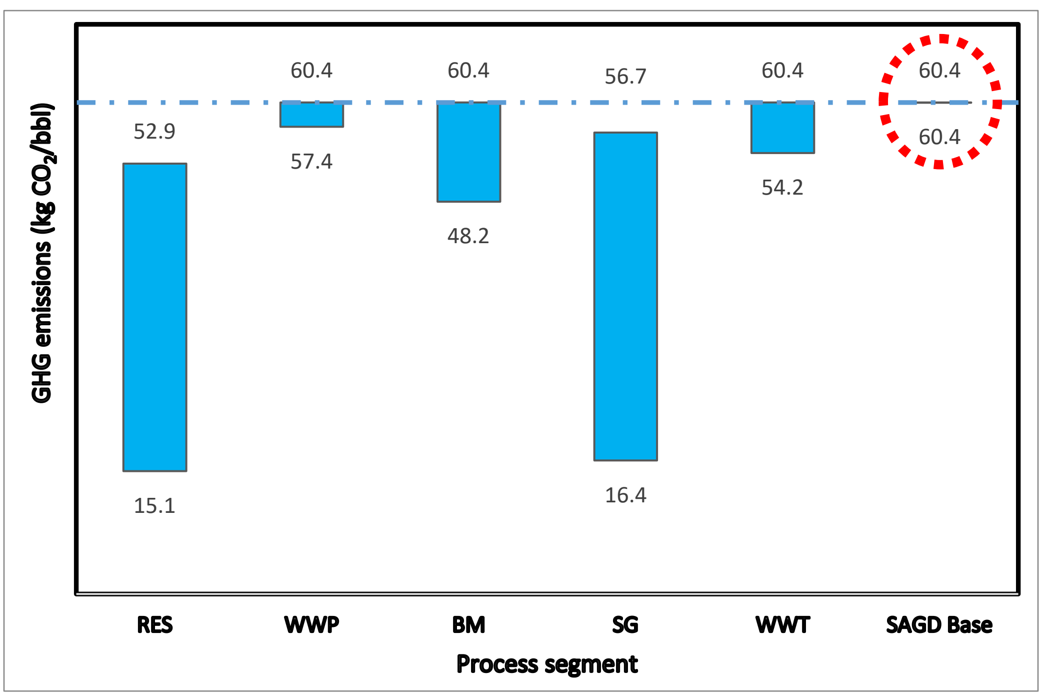
Supply cost reductions from other SG technologies are below 3 percent that of the SAGD Base. However, some of these technologies are already commercially available and are likely to be more widely deployed than the SOFCs.

Incremental cost reductions are achievable through other segments, mainly in WWP, BM, and WWT with potential supply cost reductions of C$0.80-$1.10, C$1-$1.70 and C$0.0-$1.30 per barrel, respectively.

GHG Emissions from Bitumen Production

The potential for the process segments to reduce direct fuel-derived emissions of bitumen extraction are assessed. In this section, flaring and fugitive emissions and emissions from electricity (grid or cogeneration) generation are excluded. This is because most of the technologies assessed do not target reducing emissions associated with electricity generation, flaring or venting. Also, given that significant portions of the electricity requirements of the oil sands industry are met by the Alberta electric grid, the associated electricity generation emissions are not directly attributed to oil sands production. Based on the existing carbon policy regulations, the power producers are directly responsible and pay carbon tax for the GHG emissions they generate.

Figure 4.2: Range of Direct GHG Emissions for Various Bitumen Extraction Process Segments



Source: CERI

Figure 4.2 is a range plot for bitumen extraction emissions. It shows the range of direct GHG emissions associated with implementing oil sands technologies under the RES, WWP, BM, SG and WWT segments. The GHG emissions from each segment are compared to the SAGD Base (60.4 kgCO_2e/bbl bitumen). From Figure 4.2 the potential emissions reductions can be deduced. The blue horizontal dashed line in represents direct GHG emissions of the SAGD Base (60.4 kgCO_2e/bbl).

Interestingly, the RES and SG (steam with CO_2 co-injection) segments which gave the lowest supply costs, are also most likely to achieve the greatest direct emissions reductions.[82] The RES technologies have the greatest promise for emissions reduction followed by steam generation technologies. Marginal emissions reductions come from the other segments (wells/well pads, data analytics-based steam flood management under the BM segment, and water/wastewater treatment).

The RES and SG segments can independently reduce direct GHG emissions of the SAGD Base by 70-75 percent. This is achieved by technologies such as *pure solvent* extraction and *DCSG*.

The *pure solvent* reservoir process uses heated condensing solvents such as propane or butane in *lieu* of steam for bitumen extraction in reservoirs. The fact that the solvent is only heated to about 60°C consequently reduces the energy intensity of the process to about 25 percent relative to the SAGD Base. Further energy efficiency improvements and emissions reductions are possible if the pure solvent process uses cogeneration equipment to meet its energy requirements. However, as mentioned earlier, the economics of an industry-wide adoption of cogeneration is uncertain.

The pure solvent process, the Nsolv process in particular, is at a field demonstration stage, and claims to have shovel-ready plans to build a 10,000 bbl/day commercial demonstration facility in their next phase of development. It would be expected that issues related to solvent losses in the reservoir, as well as solvent retention in the final bitumen product be clearly understood. Additionally, the economic feasibility of pure solvent process applications must be favorably established for a variety of reservoirs with different geological characteristics if this technology is to be widely deployed by the industry.

The SG segment realized low levels of emissions as shown in Figure 4.2 through the use of DCSG. An example of this technology is the NRCAN's DCSG. Based on previous studies,[83] it is assumed that 30-60 percent of the CO_2 generated from combustion can be sequestered by co-injecting steam and flue gases into the reservoir. The rest of the emissions reductions (up to 12 percent) come from an efficient heat transfer mechanism and waste heat utilization. The nature of the direct contact steam generation boiler makes it possible to reach a thermal efficiency of up to 98

[82] Direct emissions do not include electricity, flaring and fugitive emissions.
[83] Nduagu, E.I, Gates, I.D., 2014. An ultra-low emissions enhanced thermal recovery process for oil sands. Energy Procedia, 63, 8050-8061.

percent. In addition to that, the steam together with flue gases is injected into the reservoir, a process that eliminates waste heat.

However, the *DCSG* faces important technical and economic setbacks. First, the use of oxygen for combustion incurs significant additional capital and operating costs associated with oxygen production requirements through an air separation facility. Second, high temperature corrosion can take place in the combustor due to the presence of hydrogen sulphide and organic acids when untreated process-affected water is fed into the combustor. Third, favorable performance of co-injecting non-condensable gases, such as CO_2, with steam into a SAGD-type process have not been clearly demonstrated. For example, steam-CO_2 co-injection results in low oil production rates. Fourth, CO_2 leakage issues and the long-term fate of the CO_2 contained in the oil sands reservoirs are important issues that need to be addressed. The enormity of these challenges show that this technology may require lengthy experimentation and piloting before it can be considered commercially ready.

In terms of GHG reductions, the *electromagnetic heating* process, which also uses pure condensing solvent performs more favorably (55 percent less than SAGD baseline) relative to its supply costs reduction performance. This result is obtained by assuming that there is an on-site cogeneration plant that meets the electricity requirements of the process. However, if electricity is drawn from the grid, direct GHG emissions of the process becomes insignificant. In that case, the *electromagnetic heating* process becomes the technology with the least direct emissions. However, the high supply costs associated with this process make it uncompetitive, at least in the short term.

Interestingly, in the BM segment, data analytics, particularly steam flood and production optimization technologies, result in considerable emissions reduction, and higher return on investment with low adoption cost but relatively high performance. Examples of technologies under this segment are *SAAS*, *Atmion* and *Thermion* from Tachyus; these technologies can together realize an average SOR reduction of 20 percent through steam flood optimization. Similarly, another analytics company, SAS uses its production optimization solution to achieve a production increase of about 7 percent-17 percent. Reductions in SOR and/or production improvements results in proportionate reductions in emissions intensity.

Optimal Technology Configurations

In this section, optimal facility configurations are identified (Table 4.1) – these configurations incorporate the potential costs and emissions reductions from different compatible technologies within and across the process segments.

Table 4.1: In Situ Oil Sands Production and Processing Segments and their Associated Technologies

<table>
<tr><th rowspan="2"></th><th colspan="6">Compatible Processes and Technologies</th></tr>
<tr><th colspan="2">BM</th><th>WWP</th><th>RES</th><th>WWT</th><th>SG</th></tr>
<tr><td colspan="7">Brownfield Development</td></tr>
<tr><td>Steam solvent</td><td></td><td>Steam flood management</td><td></td><td>Steam Solvent</td><td>Magox precipitation and CO_2 conversion</td><td>OTSG</td></tr>
<tr><td colspan="7">Greenfield Development</td></tr>
<tr><td>Steam with CO_2 co-injection</td><td rowspan="5">Digitalization of EPC</td><td rowspan="5">Steam flood management</td><td rowspan="5">Well pad standardization</td><td>Steam/CO_2 co-injection</td><td rowspan="2">Evaporator</td><td>DCSG</td></tr>
<tr><td>Steam with CoGen</td><td>Steam</td><td>SOFC</td></tr>
<tr><td>Steam-solvent</td><td rowspan="2">Steam Solvent</td><td rowspan="2">Chemical water treatment</td><td>RT-OTSG</td></tr>
<tr><td>Steam-solvent Cogen</td><td>SOFC</td></tr>
<tr><td>Pure Solvent</td><td>Pure Solvent</td><td></td><td></td></tr>
</table>

Source: CERI

The costs and GHG emissions shown for different segments above (see Figures 4.1 and 4.2) can be compounded considering brown and greenfield developments. Compatible technologies within and across the process segments are considered by eliminating mutually exclusive technologies and processes.

The cumulative economic and direct GHG emissions impacts of adopting a given technology or process are captured as an overall impact, relative to the baseline SAGD facility. Six optimal configurations comprising compatible technologies from the process segments are identified; one for the brownfield and five for the greenfield facilities.

For a brownfield development, the optimal technology configuration (Table 4.1) is one that requires only a slight modification of the existing plant and infrastructure but could have a notable potential for cost and emissions reductions. A brownfield case pertains to a currently existing SAGD facility whereas a greenfield relates to plants that will become operational after 2017.

Brownfield Facility Configuration

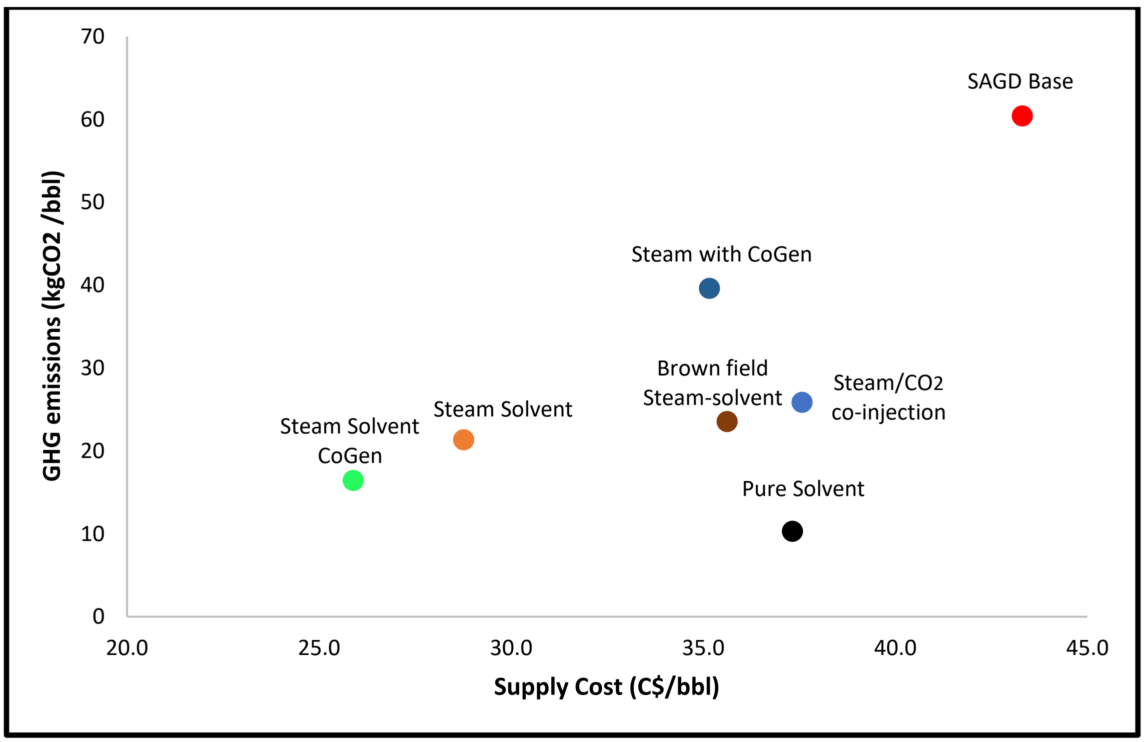
For brownfield production, only cost minimization is applicable. The technologies with high potentials to reduce GHG emissions are relatively capital-intensive because they require a significant modification of the existing equipment and facilities. Thus, these technologies are not considered to be suitable for deployment in a brownfield due to high CAPEX. Suitable technologies for brownfield developments are chosen based on their ability to allow only slight modification of existing infrastructure but have a potential for notable cost reduction (Table 4.1).

The technology configuration that suits brownfield development is the steam solvent configuration. This configuration combines once-through steam generators (OTSGs), steam solvent reservoir technologies such as Solvent-Aided Process (SAP) or the Steam Assisted SAGD (SA-SAGD), data analytics-based steam flood management (e.g., software solutions from Tachyus or SAS) and dissolved magnesium addition in lime softening and CO_2 conversion (CH2M technology).

Relative to the SAGD Base, the total impact of the brownfield steam-solvent configuration is an 18 percent and 61 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

Figure 13 shows the impact on supply cost and emissions by the identified optimal technology configurations applicable to green and brownfields facility configurations.

Figure 4.3: Combined Impact of Technologies under Different Cost and GHG Emissions Scenarios



Source: CERI

Greenfield Facility Configuration

Greenfield development benefits from a high flexibility to combine different mutually inclusive technologies within and across the different process segments. Five optimal technology configurations are suitable for greenfield development (Table 4.1).

Three technologies from two process segments (BM and WWP) are applied to the five greenfield technology configurations. These technologies are digitalization of Engineering Procurement and Construction (EPC), well pad standardization and data analytics-based steam flood management. Vista Projects is one of the companies that uses digitalization of EPC through the integrated data portal, Aveva Net to deliver capital cost reductions.

In addition to these technologies, each greenfield technology configuration comprises other complementary technologies as explained below:

- The *steam with CO_2 co-injection* technology configuration uses direct contact steam generation (DCSG) with co-injection of steam and CO_2 into reservoirs and the use of evaporator in water treatment. The DCSG is a technology that allows steam to be produced by directly contacting water with hot flue gases (a mixture of CO_2 and steam) in order to vaporize the water without the need for boiler tubes. The entire product gas is to be injected into a reservoir where about 30-60 percent of the injected CO_2 are assumed to be sequestered.

Relative to the SAGD Base, the total impact of this technology configuration is 13 percent and 57 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

- The *steam with CoGen* technology configuration comprises cogeneration of steam and electricity by solid oxide fuel cells (SOFC) and evaporator use in water treatment. SOFC generates energy directly by chemically reacting a fuel (hydrogen, hydrocarbons or carbon monoxide) and oxygen, rather than by combustion, with an overall efficiency of 80 percent. Here, natural gas is used as fuel and only steam is injected into the reservoir for bitumen mobilization.

Relative to the SAGD Base, the total impact of this technology configuration is 19 percent and 34 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

- The *steam-solvent* technology configuration combines rifle tube once-through steam generator (RT-OTSG), steam solvent reservoir technologies (such as SAP or SA-SAGD) and chemical water treatment. The chemical water treatment process refers to the front-to-back (FTB) process. The FTB process is made up of a Dissolved Gas Flotation (DGF) unit, a high temperature electrocoagulation (EC) unit, a filtration step, and rifle tube boiler. An ion exchanger can be added after the filter press for polishing.

Relative to the SAGD Base, the total impact of this technology configuration is 34 percent and 65 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

- The *steam-solvent Cogen* technology configuration uses a combination of steam-solvent reservoir technology (e.g., SAP, SA-SAGD, etc.), SOFC cogeneration of steam and power and FTB water treatment process. In the *Steam-solvent Cogen* configuration, a mixture of steam and solvents are injected into the reservoir.

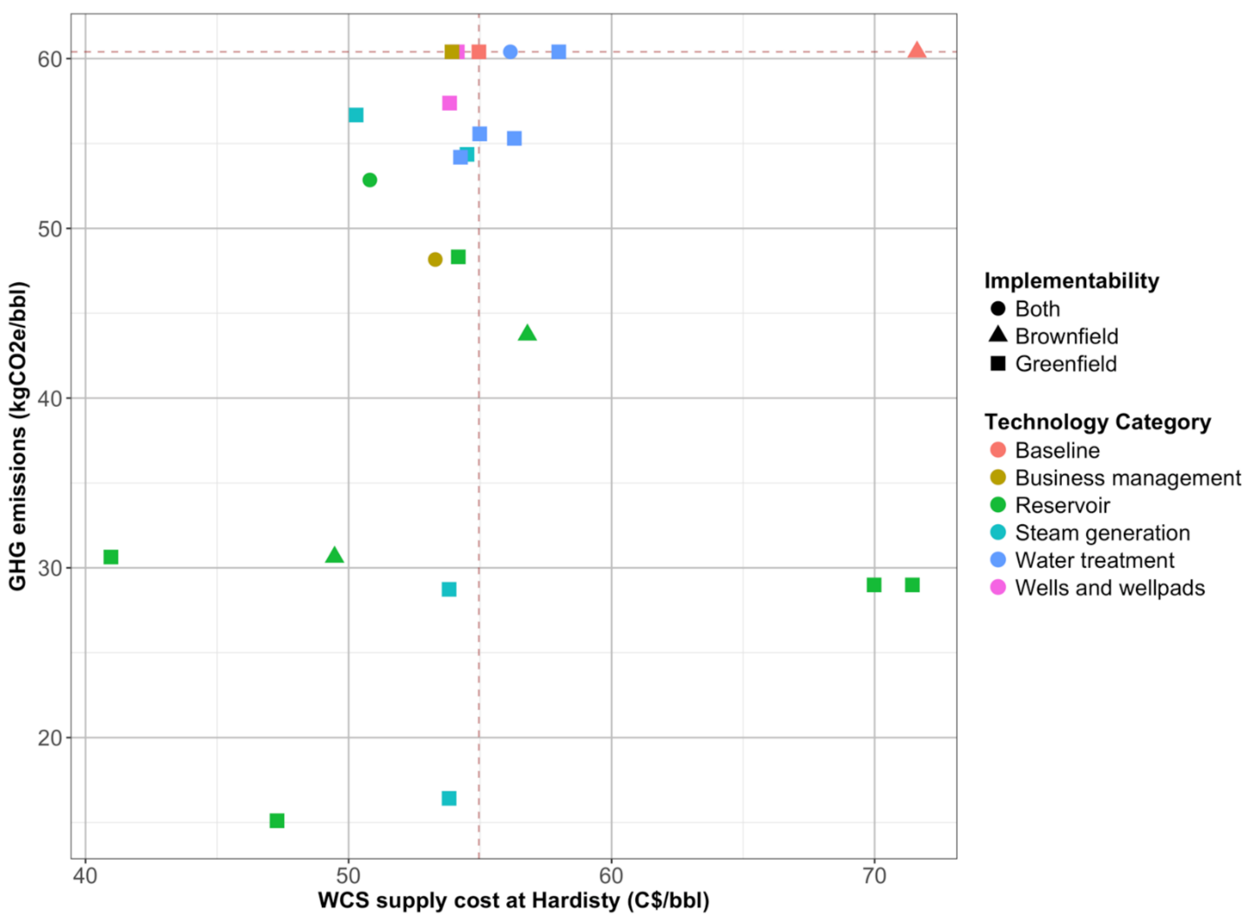
Relative to the SAGD Base, the total impact of this technology combination is 40 percent and 73 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

- The *pure solvent* technology configuration uses pure solvent reservoir technology (such as the Nsolv process), which precludes the use of steam for bitumen recovery. Consequently, SG and WWT segments are of no significance. However, the process still requires treatment of produced water and energy for solvent heating and purification.

Relative to the SAGD Base, the total impact of this technology configuration is 14 percent and 83 percent reduction in supply cost and direct GHG emissions, respectively (Figure 4.3).

Overview of Results from Technologies Assessed

Figure 4.4: Direct GHG Emissions and Western Canadian Select (WCS) Supply Costs for Different Technologies Assessed under Each Technology Category



Source: CERI

Figure 4.4 shows the direct GHG emissions and supply costs (in Canadian dollars) when different technologies under each technology category are used for in situ bitumen extraction and processing. The supply costs presented here are benchmarked against the Western Canadian Select crude, which is sold at Hardisty. In total, twenty-three technologies are assessed; these include ten reservoir, two wells and well pads, two business management and data analytics, four steam generation, and five water and waste treatment technologies. Color schemes indicate the technology categories whereas shapes of the data points show whether the technology can be applied to a brownfield (triangle) or greenfield (square) development or both (circle).

The orange data points show the baselines for greenfield (orange square) and brownfield (orange triangle) developments. The dotted orange vertical and horizontal lines specify the Western Canadian Select supply cost and direct GHG emissions for the greenfield facility. A key finding from the results of this assessment is that the majority of the technologies assessed show potential to reduce both GHG emissions and supply costs below that of the greenfield facility baseline. Also, the reservoir and steam generation technology are key technology opportunity segments that bring the highest emissions and cost reductions.

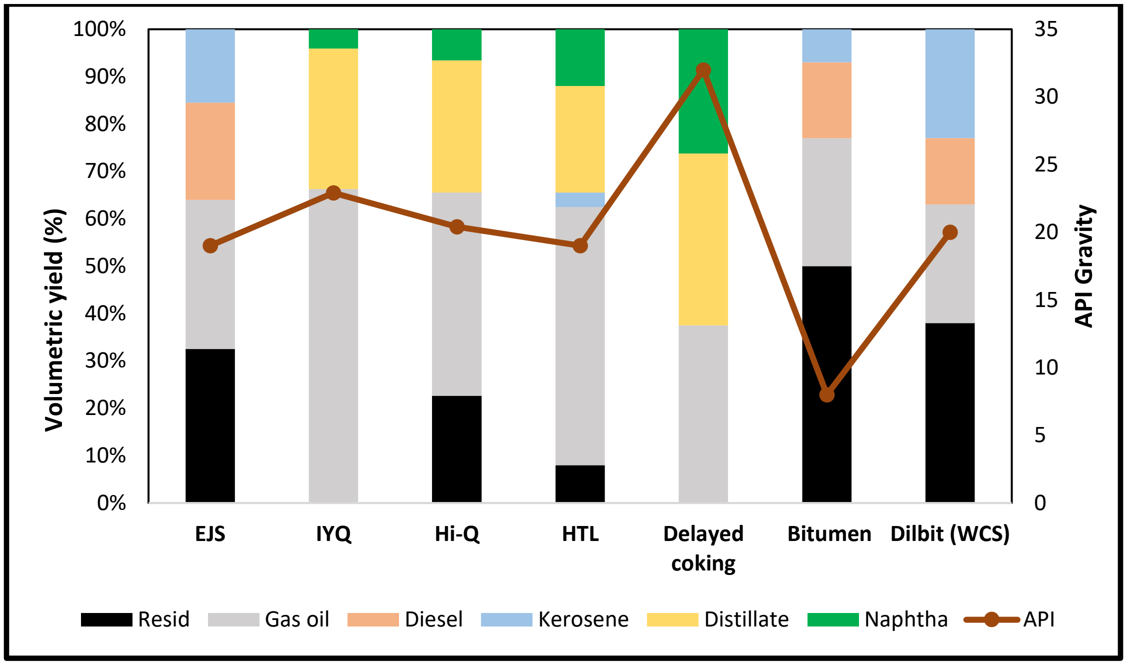
Upgrading

The assessments of the segments presented above centre on bitumen extraction at the field gate, but partial and full upgrading are essential value add components of the overall oil sands process. A significant share of costs and emissions of oil sands are associated with full or partial upgrading or blending.

Major promising technologies assessed under this segment are EJS (Enhanced Jetshear) by Fractal Systems, $I^{Y}Q$ (Increased Yield and Quality) by ETX Systems, Hi-Q® by MEG Energy, HTL by Fluid Oil (formerly Ivanhoe Energy), DSU™ by Field Upgrading and CCC by Bayshore Petroleum.

A few important parameters that determine the extent of value addition for a partial or deep conversion technology includes the distillation profile and volumetric yield of the products and the products' viscosity. The products from the partial upgrading and deep conversion technologies vary in chemical and physical characteristics and economic value. Figure 4.5 shows how these parameters vary widely for partial and full upgrading and deep conversion technologies.

Figure 4.5: Volumetric Yield and API Gravity of Products from Partial and Full Upgrading Technologies

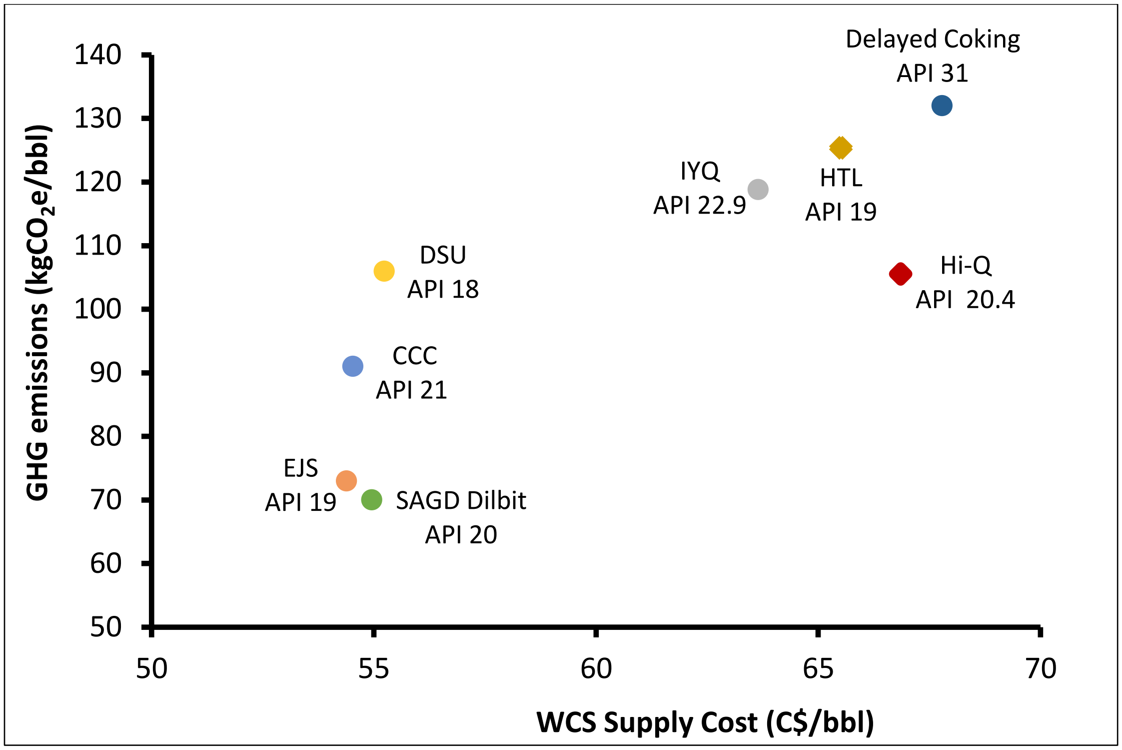


Source: CERI

These technologies are developed to reduce diluent requirements or as alternatives to diluent addition or full upgrading. These technologies are assessed using economic and environmental performances of dilbit and SCO (from delayed coker) as benchmarks. Some of the technologies, for example, those that dramatically reduce vacuum resid such as I^{Y}Q, HTL, Hi-Q, etc., aim to achieve deep conversions and, thus, preclude the use of diluent. Their products would be priced higher than those that require diluent addition.

These technologies are assessed relative to dilbit (diluted bitumen) and fully upgraded synthetic crude oil (SCO) from delayed coking. On a Western Canadian Select (WSC)-equivalent basis, the supply costs for products from partial or full upgrading technologies are assessed at the facility gate. The product quality is brought to a WCS-equivalent basis by blending with diluent when required. The WCS-equivalent assumes a pipeline-ready dilbit with an API gravity of 20. The WCS-eq. supply costs and associated emissions of the products from the partial upgrading technologies are shown in Figure 4.6.

Figure 4.6: GHG Emissions and Supply Cost of Partial and Full Upgrading Technologies



Source: CERI

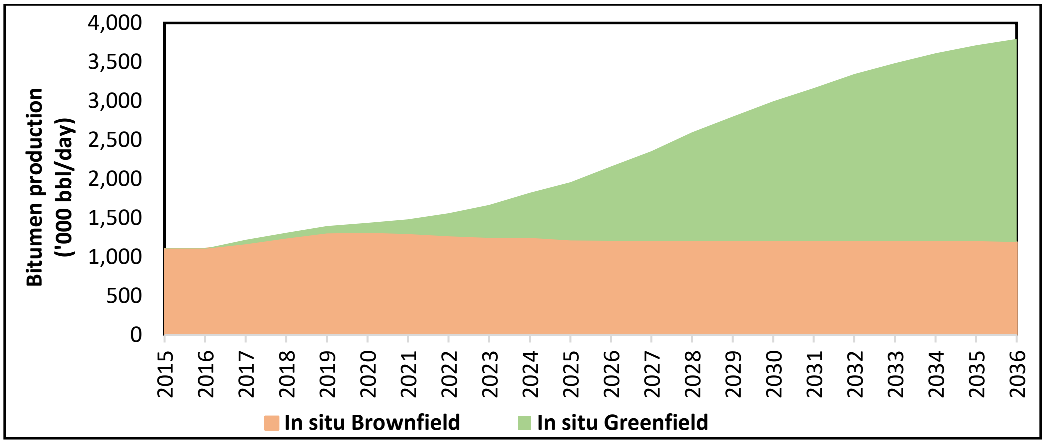
The partial upgrading technologies show potential to add value to bitumen without significantly increasing costs and emissions. However, when brought to West Texas Intermediate (WTI)-equivalent, which is a product that is comparable to the SCO product grade, the supply costs of some of the technologies may not be considered competitive in a low oil price environment.

Though a supply cost based assessment of partially upgraded products provides some insights into the economics of the technologies, varying product make-up and characteristics (conversions, distillation fractions, API gravity, total acid number, sulphur content, etc.) make this assessment complex. Thus, a more comprehensive approach would involve an understanding of the price that the refiners are willing to offer for the value add through partial upgrading. However, such extent of analysis is beyond the scope of this study.

Oil Sands Production Growth

CERI's oil sands projection is used to determine bitumen production from in situ brownfield and greenfield developments within the study period (see Figure 4.7).

Figure 4.7: Brown and Greenfield In Situ Oil Sands Production Forecast

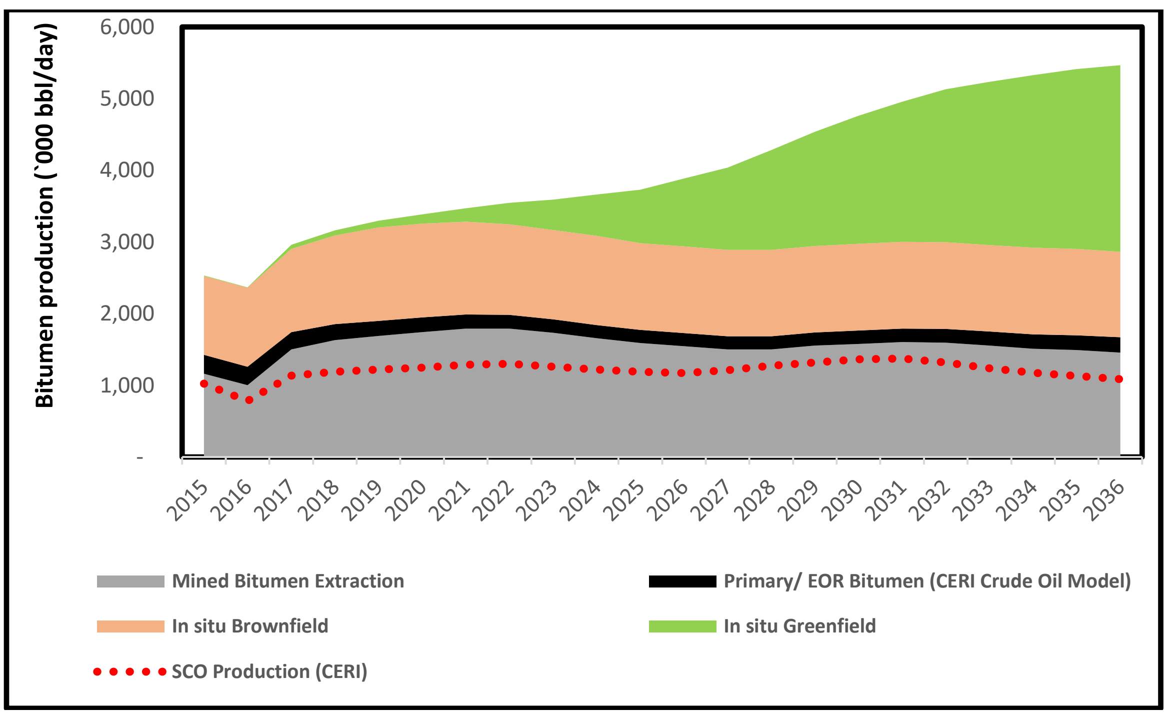


Source: CERI

In situ bitumen production covers SAGD and CSS processes. With the assumption of a project life of 30 years, most brownfield projects today would still be operational by 2036. Thus, no significant change in brownfield developments is expected.

However, greenfield development may experience notable growth between 2016 and 2036, resulting in an increase of *in situ* bitumen production from 2016 levels of 1.1 million bbl/day to 3.8 million bbl/day in 2036. The in situ production profile is later used to determine in situ emissions profile for the SAGD Base and for cases where new technologies were applied.

Figure 4.8: Oil Sands Production Forecast



Source: CERI

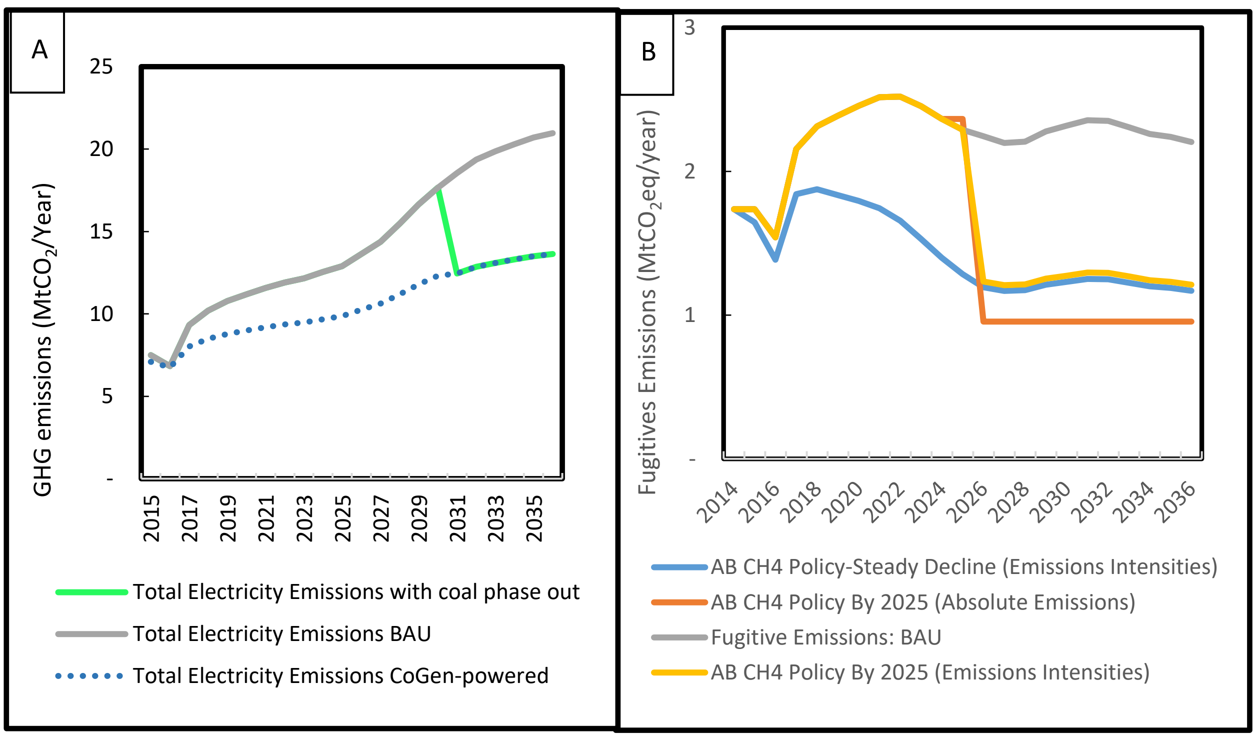
An overall picture of oil sands production growth from in situ, mining, and primary/enhanced oil production (EOR) processes can be seen in Figure 4.7. The deflation seen in Figure 4.8 is a result of the forest fire incident that caused a temporary shutdown of oil sands operations in 2016.

While oil sands production from in situ bitumen extraction methods is expected to experience growth within the next 20 years, bitumen mining is likely to slightly increase in the next few years and level-off afterwards. Most of the future production growth will come from in situ production.

Policy Changes

Two additional provincial regulations, particularly, phase-out of coal-fired power generation and oil and gas methane emissions reduction regulations in Alberta will affect oil sands industry emissions. As of 2015, the coal- and natural gas-fired electricity generation constitute 51 percent and 39 percent of the generation options in Alberta with the rest generated by renewables.[84]

Figure 4.9: Regulatory Impacts: Coal Power Phase-out (A) and CH_4 Emissions Reduction (B)



Source: CERI

Electricity requirements and associated emissions intensities of mining (14.7 kWh/bbl), in situ (16.7 kWh/bbl), primary production (13 kWh/bbl), and upgrading (10.7 kWh/bbl) are used in combination with bitumen production projections[90] to assess oil sands industry on site and imported electricity use emissions profile. The emissions intensity of Alberta's electricity grid and

[84] Alberta Energy, Electricity Statistics. Available at http://www.energy.alberta.ca/electricity/682.asp

natural gas combined cycle (NGCC) are assumed to be 760 $kgCO_2$ and 390 $kgCO_2$ per MWh electricity, respectively.

Two hypothetical cases of no coal-power phase out (*Total Electricity Emissions BAU*) and full deployment of NGCC for all oil sands operations (*Total Electricity Emissions CoGen-powered*) are considered.

Results (Figure 4.9A, *Total Electricity Emissions BAU*) show that without implementation of the coal phase-out policy, direct and indirect emissions from oil sands electricity requirements will rise from current 8 $MtCO_2e$ per year levels to almost 30 $MtCO_2e$ per year by 2036.

If CoGen is fully deployed to meet all the power requirements of the oil sands industry, an emissions profile (Figure 4.9A, *Total Electricity Emissions CoGen-powered*) that is significantly lower than that of the "*Total Electricity Emissions BAU"* profile is observed before the planned coal power phase-out in 2030.

Coal phase-out brings significant reductions in oil sands electricity use emissions. This is evident from the profile "*Total Electricity Emissions with coal phase out"*. This profile is generated by assuming the existing coal power stock in Alberta is replaced by NGCC power plants. Beyond 2030, this assumption could vary significantly given the uncertainties of the Alberta power generation make-up. However, there is a high probability that most of the coal power fleet in Alberta will likely be replaced by natural gas-fired plants. Thus, our assumption is reasonable. Consequently, coal phase-out is likely to bring electricity emissions reduction benefits of more than 5 $MtCO_2e$ per year by 2030.

Similarly, emissions reductions are anticipated from Alberta's methane emissions regulation. This regulation requires oil and gas facilities to reduce methane emissions by 45 percent relative to 2014 levels by 2025. There is currently no detail about how this regulation will be implemented. Therefore, as shown in Figure 4.9B, we modeled a business as usual case (*Fugitive Emissions: BAU*) and three implementation scenarios:

1) *AB CH4 Policy-Steady Decline (Emissions Intensities).* This scenario implements a steady reduction of fugitive and flaring emissions on an intensity basis to reach the 45 percent reduction by 2025.

2) *AB CH4 Policy By 2025 (Absolute Emissions)*. This scenario applies the entire 45 percent reduction of fugitive and flaring emissions on an absolute basis by 2025.

3) *AB CH4 Policy By 2025 (Emissions Intensities).* Here, 45 percent reduction of fugitive and flaring emissions on an intensity basis is implemented by 2025.

The results show that the scenarios modeled can achieve fugitive and flaring emissions reduction of 1-1.4 MtCO2/year by 2025. The *"AB CH4 Policy By 2025 (Absolute Emissions)"* scenario which is based on absolute emissions reduction achieves, by 2025, about 0.4 MtCO2/year more reduction than the other intensity-based scenarios.

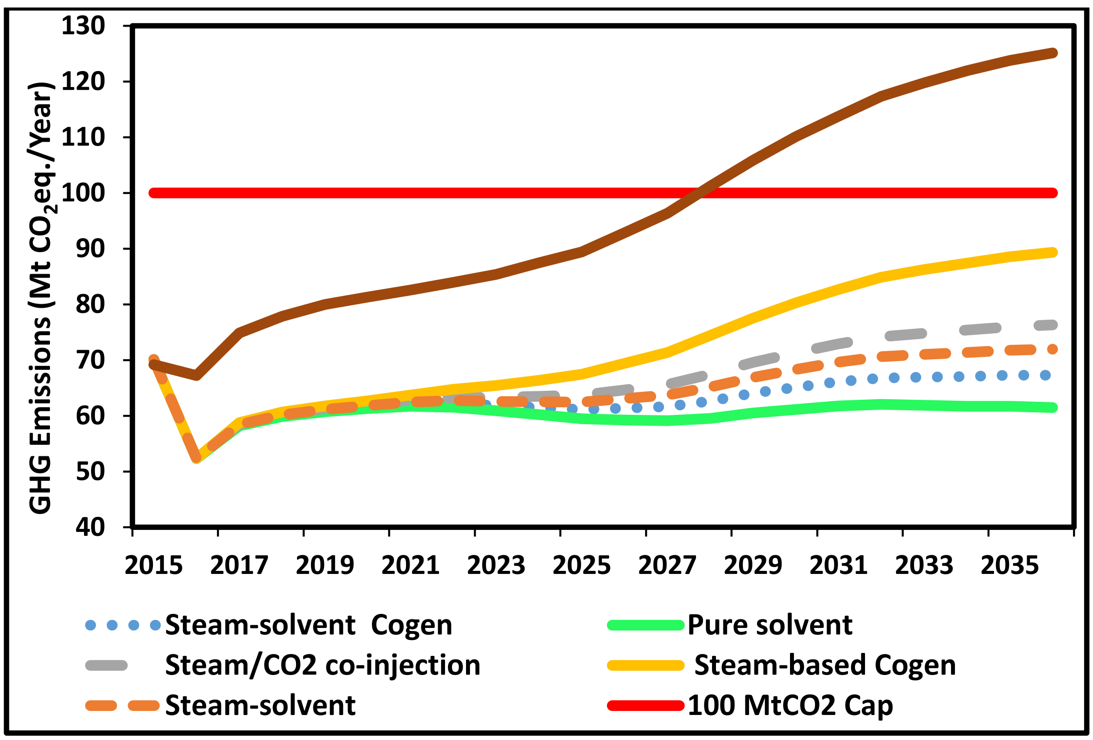
However, for the assessment of overall oil sands emissions profiles, the scenario that implements a steady reduction approach, the *"AB CH4 Policy-Steady Decline (Emissions Intensities)"* is used.

Oil Sands Emissions Profile

The different technology configurations (in Table 4.1 and Figure 4.3) result in new direct emissions profiles[85] for the oil sands industry and these are compared with the business as usual profile (***BAU with policy changes***[86]) which represents the emissions profile for the SAGD Base and the ***100 MtCO₂ cap*** in in Figure 4.10.

Under the Climate Leadership Plan,[87] the Government of Alberta legislated (Oil Sands Emissions Limit Act)[88] a hard limit of 100 Mt CO_2eq. per year on oil sands operations to spur efficiency improvements that yield higher productivity with fewer carbon emissions per barrel.

Figure 4.10: GHG Emissions Profile for the Oil Sands Industry and the 100 MtCO₂/year Emissions Cap



Source: CERI.

[85] Based on the oil sands production forecast generated in the CERI's 2016 oil sands update.
[86] The profiles in Figure 19 include current direct and indirect emissions of all the oil sands production methods (mining, in situ, enhanced oil recovery and primary heavy oil production) and upgrading. Policy changes refer to the coal phase-out and methane emissions reductions.
[87] Climate Leadership Plan of the Alberta Government. See https://www.alberta.ca/climate-leadership-plan.aspx
[88] Fall 2016 – Bill 26: Oil Sands Emissions Limit Act. Available at https://albertandpcaucus.ca/our-work/project/fall-2016-bill-25-oil-sands-emissions-limit-act

The observed deflation (in 2016) in the emissions profile can be explained by the downturn due to global oil glut and Alberta wildfires in 2016.

The results show that the ***BAU with policy changes*** profile[89] will reach the 100 Mt CO_2eq. per year cap by 2028. Although 70.1 MtCO_2 emissions is observed in 2015, the 2016 wild fires in Fort McMurray, which led to the shutdown of a number oil sands facilities, reduced emissions levels to 67.2 MtCO_2 that year.

Over 2015-2036, all the emissions profiles (***BAU with policy changes*** profile and those of the technology configurations) consist of direct and indirect emissions from current mining, in situ, primary recovery and upgrading capacities. However, in accordance with emissions regulation provisions, imported electricity, future cogeneration and upgrading emissions are excluded after 2016.

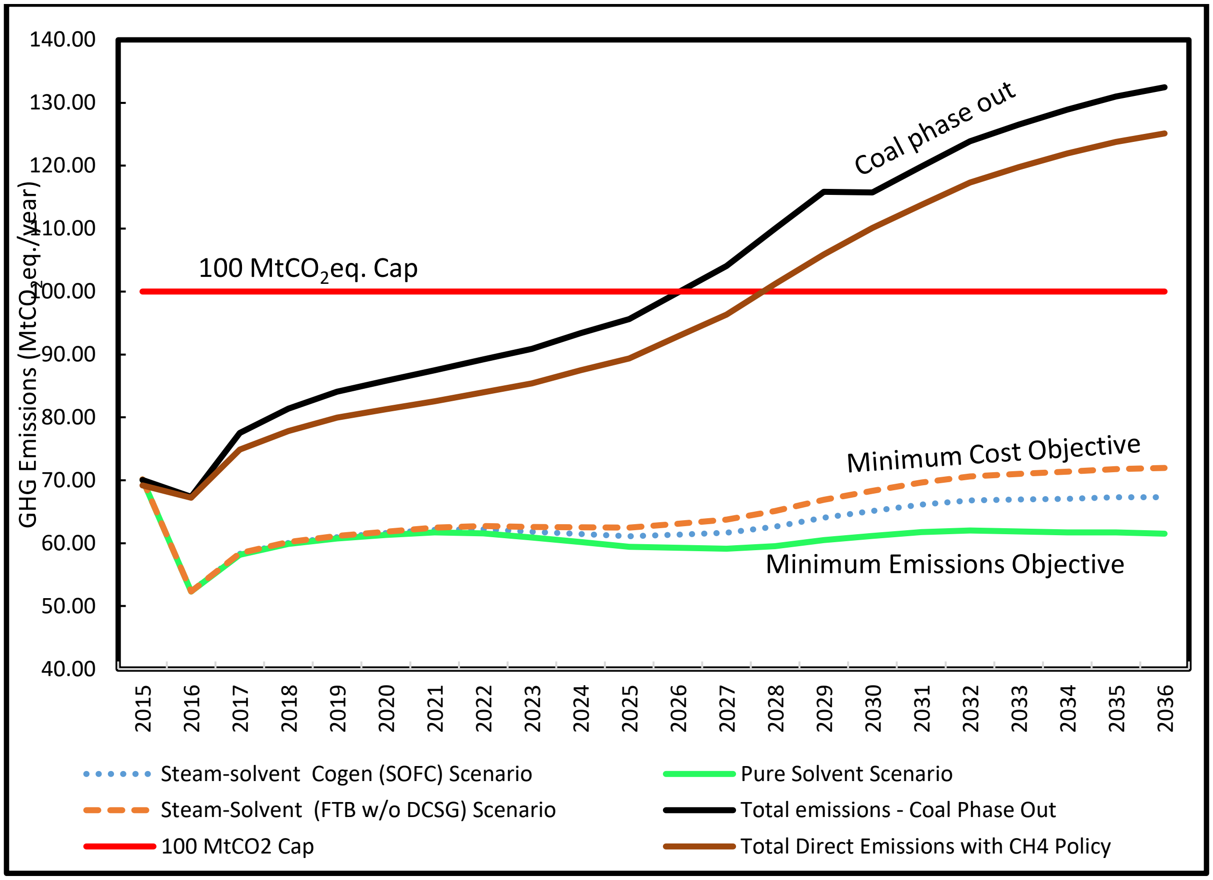
The new GHG emissions profiles[90] generated from the optimal cost and emissions technology configurations will allow for oil sands production growth within the allowed emissions cap. These technology configurations have the potential to reduce bitumen supply cost by 40 percent, avoid reaching 100 Mt CO_2eq. per year cap during the study period (2016-2036) and further delay the time until the emissions cap is reached by several decades.

Costs and GHG Emissions Minimization Objectives

Minimizing cost and GHG emissions are considered to be two principal objectives that will drive decision-making in technology development and commercialization. A combination of technologies is applied to brown and green field production considering these two objectives.

[89] Included in this profile are the current direct and indirect emissions of all the oil sands production methods (mining, in situ, enhanced oil recovery and primary heavy oil production) and upgrading.
[90] Based on the oil sands production forecast generated in the CERI's 2016 oil sands update.

Figure 4.11: GHG Emissions Profile for the Oil Sands Industry and the 100 $MtCO_2$/year Emissions Cap with Coal Phase-Out



Source: CERI

In a low-price environment, producing at the lowest possible supply cost is a necessity; therefore, technologies that realize the minimum cost objective are preferred.

However, given an imposed carbon tax and a 100 $MtCO_2e$/year emissions cap on the oil sands industry, producing at lower GHG intensity becomes reasonable and sustainable.

A simplified version of the emissions profiles in Figure 4.10 are presented in Figure 4.11. In Figure 4.11, the profiles generated from the minimum emissions and cost objectives are shown. Also included in Figure 4.11 are SAGD Base profiles with or without future cogeneration additions or grid electricity.

As shown in Figure 4.11, these objectives lead to a 34-40 percent (a C$14.50/bbl-C$17.40/bbl reduction)[91] and 82 percent (a 50.1 $kgCO_2$/bbl reduction) reduction in bitumen supply costs and direct GHG emissions, respectively, relative to the SAGD Base.

[91] The range for cost reduction considers both the *steam solvent* and the *steam solvent* technology configurations to be minimum cost cases.

The minimum cost objective profiles are the steam-solvent process with Cogen, which is shown as "*Steam-solvent Cogen (SOFC) Scenario*" in Figure 4.11 and the steam-solvent process without Cogen or DCSG, which is represented as "*Steam-solvent FTB w/o DCSG Scenario*". These objectives lead to a 34-40 percent (a C$14.50/bbl-C$17.40/bbl reduction)[92] reduction in bitumen supply costs relative to the SAGD Base. However, solid oxide fuel cells face technical challenges that make them unfeasible for short term commercial application. Therefore, the minimum cost technology configuration is likely to be the steam-solvent configuration with a potential cost reduction of 34 percent relative to the SAGD Base.

The minimum emissions objective profile is the *pure solvent* process, which is shown as "*Pure Solvent Scenario*" in Figure 4.11. This profile leads to an 82 percent (a 50.1 $kgCO_2$/bbl reduction) reduction in direct GHG emissions relative to the SAGD Base.

Note that the *BAU with policy CH4 Policy* profile and those of the minimum emissions and costs objectives consist of direct and indirect emissions from current mining, in situ, primary recovery and upgrading capacities. However, in accordance with emissions regulation provisions, imported electricity, future cogeneration and upgrading emissions are excluded after 2016. In accordance with the emissions cap regulation, the 100 $MtCO_2$eq. cap will be reached by 2028.

However, if the imported electricity and future cogeneration are included, the profile obtained shows an increase in emissions as seen from the emissions profile, "*Total Emissions – Coal Phase Out*" (Figure 4.11). The deflation seen on this profile by 2030 is a result of coal power phase-out. If direct and indirect emissions from oil sands electricity use were to be included in the 100 $MtCO_2$eq. cap, the industry will exceed the cap by 2026.

[92] ibid.

Chapter 5: Conclusions

This study shows that the costs and emissions challenges facing the oil sands industry are real and serious, and if not urgently addressed may stunt the growth of the industry. The 100 $MtCO_2eq.$ emissions per year cap imposed on the oil sands industry will be reached by 2028. This means that the industry has about 10 years to act to continue oil sands production growth by reducing its emissions intensity. On the other hand, high bitumen supply cost is another important factor that makes oil sands production less competitive relative to other competing world crude oils.

This study identifies clear technological pathways that will enable the oil sands industry to significantly reduce costs as well as emissions. Six technology configurations that reduce both bitumen supply costs and GHG emissions are identified: one for brownfield and five for greenfield developments. With the implementation of any of the configurations, chances of reaching the 100 MtCO2eq./year cap are reduced to zero within the study period (2016-2036).

More so, the technology configurations that meet the minimum costs and emissions objective criteria will allow for significantly more room for oil sands production growth. These technology configurations have the potential to reduce bitumen supply cost by 34-40 percent, reduce fuel-derived emissions from in situ oil sands production by more than 80 percent, and consequently delay the time until the emissions cap is reached by several decades.

Reducing emissions usually comes with a cost penalty. Interestingly, the results of this study prove otherwise. They show that emissions and cost reduction objectives are not adversely related. This means the two objectives can be achieved simultaneously. Even more interesting is the fact that by just choosing to implement the minimum cost objective configuration, dramatic emissions cuts are made as a result.

However, further research and development work is needed to de-risk the promising technologies through pilot and field demonstration studies if the prospects of delivering these costs and emissions reductions are to be realized. For more information on possible ways of how to fuel a greener and more cost competitive oil sands industry, see the Appendix.

Key Findings

Below are the key findings in this study:

1) The 100 $MtCO_2eq.$ emissions per year cap imposed on the oil sands industry will be reached by 2028. This means that the industry has about 10 years to act to raise the ceiling on oil sands growth by reducing its emissions intensity.

2) High bitumen supply cost is another important factor in the competitiveness of the oil sands industry.

3) Identification of clear technological pathways to significantly reduce costs as well as emissions. With the implementation of any of the configurations, chances of reaching the 100 $MtCO_2$eq./year cap are eliminated within the study period (2016-2036).

4) More so, the technology configurations that meet the minimum costs and emissions objective criteria can achieve potential reduction of bitumen supply cost by 34-40 percent, reduce fuel-derived emissions from in situ oil sands production by more than 80 percent, and consequently delay the time until the emissions cap is reached by several decades.

5) Emissions and cost reduction objectives are not adversely related. For example, by choosing to implement the minimum cost objective configuration, dramatic emissions cuts are made as a result.

6) However, further research and development work is needed to de-risk the promising technologies through pilot and field demonstration studies if the prospects of delivering these costs and emissions reductions are to be realized.

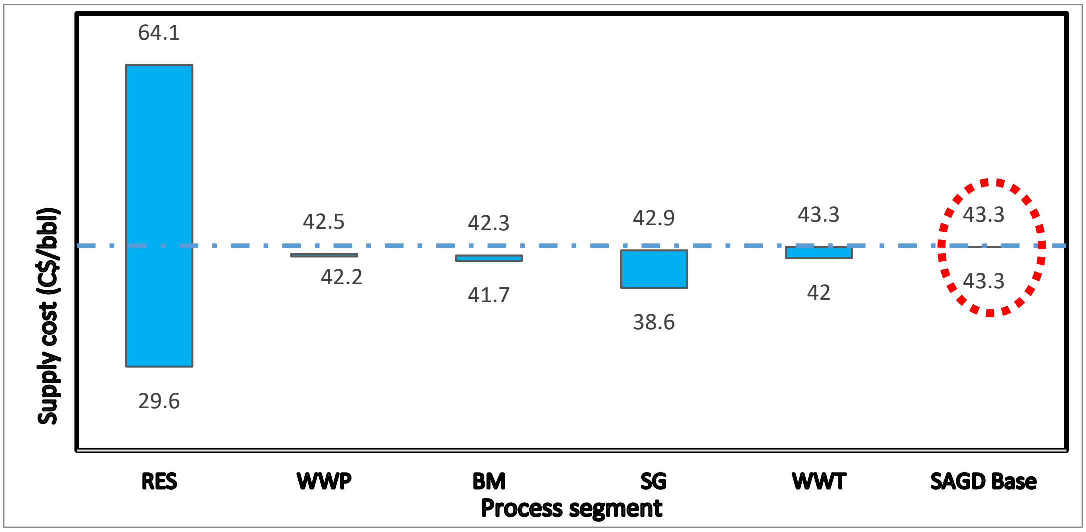
Given the depositional characteristics of bitumen in Alberta – with more than 70 percent of the resource being too deep to mine – this study focuses on in situ-based bitumen production where the majority of future developments are anticipated – covering steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) approaches. Existing in situ technologies are primarily SAGD and CSS, which require injection of high pressure and high temperature steam into oil sands reservoirs to reduce bitumen viscosity, mobilize and recover bitumen.

Therefore, a conventional SAGD facility with SOR of 3 and 30,000 barrels per day (bbl/day) production capacity is set as a baseline for this study. For our purposes, we divide in situ oil sands operations and processes into seven segments: water/wastewater treatment (WWT), steam generation (SG), wells/well pads (WWP), reservoir (RES), upgrading (UPG), pipeline/transport (PPT), and data and business management (BM).

Bitumen Production Supply Cost and GHG Emissions

The potential supply costs and fuel-derived GHG emissions performance of five of the segments (RES, WWP, BM, SG and WWT) are compared with that of the SAGD Base in Figure E.1 and Figure E.2, respectively. The results from the UPG and PPT segments are presented separately because results in these segments are presented in different units.

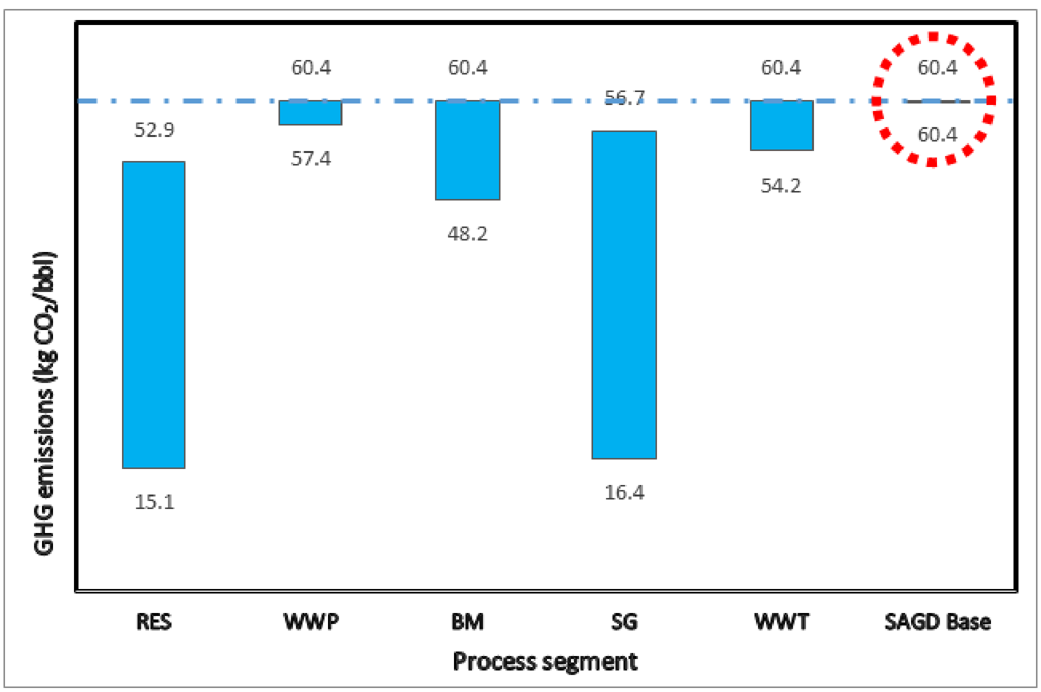
Figure 5.1: Range of Supply Costs for Various Bitumen Extraction Process Segments



Source: CERI

Figures 5.1. and 5.2. are range plots which show the ranges of supply costs and direct GHG emissions associated with oil sands technologies under the RES, WWP, BM, SG and WWT segments. The supply costs and GHG emissions from each segment can be compared with that of the SAGD Base and the potential emissions reductions from each segment deduced. The blue horizontal dashed lines in Figures 5.1. and 5.2 represent a baseline that aligns with the supply costs and direct GHG emissions associated with the SAGD Base.

Figure 5.2: Range of Direct GHG Emissions for Various Bitumen Extraction Process Segments



Source: CERI

The impacts of reservoir and steam generation technologies on supply cost reductions are most significant, with potential reductions of 32 percent and 11 percent, respectively, relative to the SAGD Base. However, some of the reservoir technologies are more cost-intensive than other alternatives, and will likely be unviable for commercialization over the next 5 to 7 years.

Similarly, reservoir and steam generation (steam with CO_2 co-injection) processes are more likely to achieve the greatest direct emissions reductions.[93] Marginal cost and emissions reductions come from the other segments (wells/well pads, data analytics-based steam flood management under the BM segment, and water/wastewater treatment).

Optimal Technology Configurations

Our assessment identifies optimal facility configurations (Table 5.1) that incorporated the potential costs and emissions reductions from different technologies under each segment.

Table 5.1: Optimal Technology Configurations for Brown and Greenfield Developments

<table>
<tr><th rowspan="2"></th><th colspan="6">Compatible Processes and Technologies</th></tr>
<tr><th colspan="2">BM</th><th>WWP</th><th>RES</th><th>WWT</th><th>SG</th></tr>
<tr><td colspan="7">Brownfield development</td></tr>
<tr><td>Steam solvent</td><td></td><td>Steam flood management</td><td></td><td>Steam Solvent</td><td>Magox precipitation and CO_2 conversion</td><td>OTSG</td></tr>
<tr><td colspan="7">Greenfield development</td></tr>
<tr><td>Steam with CO_2 co-injection</td><td rowspan="5">Digitalization of EPC</td><td rowspan="5">Steam flood management</td><td rowspan="5">Well pad standardization</td><td>Steam/CO_2 co-injection</td><td rowspan="2">Evaporator</td><td>DCSG</td></tr>
<tr><td>Steam with CoGen</td><td>Steam</td><td>SOFC</td></tr>
<tr><td>Steam-solvent</td><td rowspan="2">Steam Solvent</td><td rowspan="2">Chemical water treatment</td><td>RT-OTSG</td></tr>
<tr><td>Steam-solvent Cogen</td><td>SOFC</td></tr>
<tr><td>Pure Solvent</td><td>Pure Solvent</td><td></td><td></td></tr>
</table>

Source: CERI

The cumulative economic and direct GHG emissions impacts of adopting a combination of technologies or processes are captured as an overall impact, relative to the baseline SAGD facility. Six optimal configurations comprising compatible technologies from the process segments are identified; one for the brownfield and five for the greenfield facilities. For a brownfield development, the optimal technology configuration (Table E.1) is one that requires only a slight

[93] Direct emissions do not include electricity, flaring and fugitive emissions.

modification of the existing plant and infrastructure but could have a notable potential for cost and emissions reductions.

The technology configuration that suits brownfield development is the *steam-solvent configuration*. This configuration combines once-through steam generators (OTSGs), steam-solvent reservoir technologies such as Solvent-Aided Process (SAP) and the Steam Assisted SAGD (SA-SAGD), data analytics-based steam flood management and dissolved Magnesium addition for lime softening and CO_2 conversion.

However, greenfield development benefits from a high flexibility to combine various compatible technologies within and across the different process segments. Five optimal technology configurations are suitable for greenfield development (Table E.1). Three technologies from two process segments (BM and WWP) are applied to the five greenfield technology configurations. These technologies are digitalization of Engineering Procurement and Construction (EPC), well pad standardization and data analytics-based steam flood management. In addition to these technologies, each greenfield technology configuration comprises other complementary technologies as explained below:

- The *steam with CO_2 co-injection* technology configuration uses direct contact steam generation (DCSG) with co-injection of steam and CO_2 into reservoirs and the use of an evaporator in water treatment. The DCSG is a technology that allows steam to be produced by directly contacting water with hot flue gases (a mixture of CO_2 and steam) to vaporize the water without the need for boiler tubes. The entire product gas is to be injected into a reservoir where some of the CO_2 is expected to be sequestered.

- The *steam with CoGen* technology configuration comprises cogeneration of steam and electricity by solid oxide fuel cells (SOFC) and evaporator use in water treatment. SOFC generates energy directly by chemically reacting a fuel (hydrogen, hydrocarbons or carbon monoxide) and oxygen, rather than by combustion, with an overall efficiency of 80 percent. Here, natural gas is used as fuel and only steam is injected into the reservoir for bitumen recovery.

- The *steam-solvent* technology configuration combines rifle tube once-through steam generator (RT-OTSG), steam solvent reservoir technologies (such as Solvent-Aided Process and Steam Assisted SAGD) and electrochemical treatment. The electrochemical water treatment process refers to the front-to-back (FTB) process. The FTB process is made up of a Dissolved Gas Flotation (DGF) unit, a high temperature electrocoagulation (EC) unit, a filtration step, and rifle tube boiler. An ion exchanger can be added after a filter press for polishing.

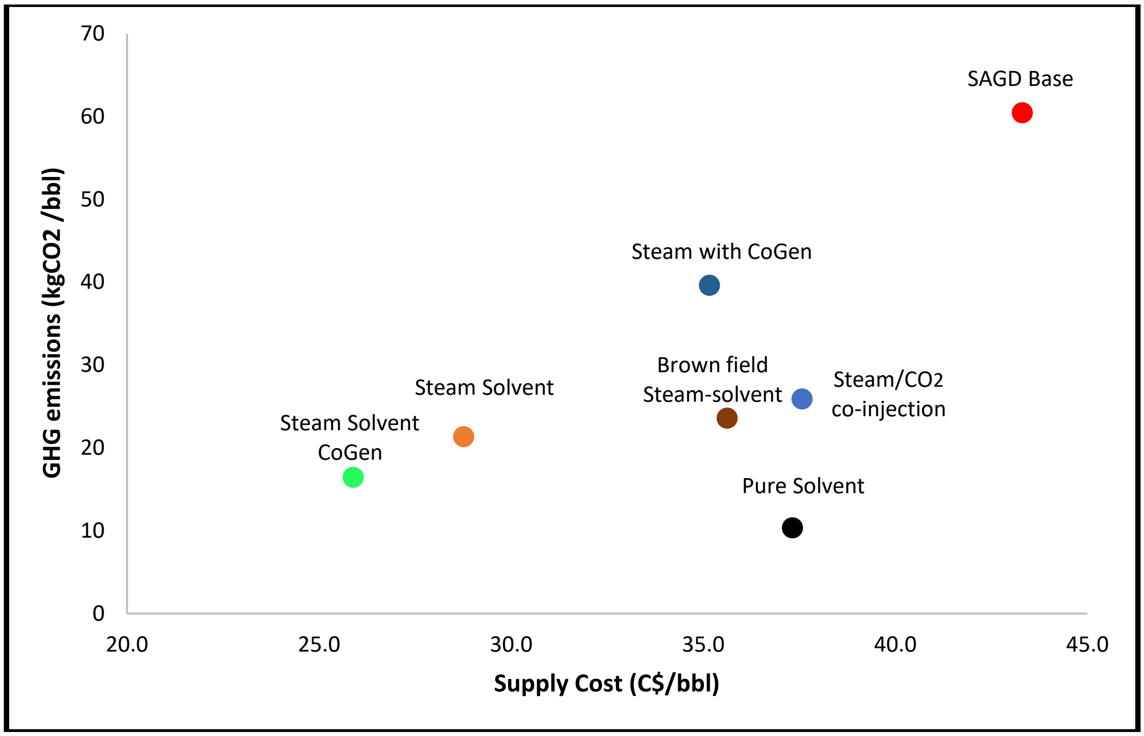
- The *steam-solvent Cogen* technology configuration uses a combination of steam solvent reservoir technology (e.g., SAP, SA-SAGD, etc.), SOFC cogeneration of steam and power and FTB water treatment process. In the *Steam-solvent Cogen* configuration, a mixture of steam and solvents is injected into the reservoir.

- The *pure solvent* technology configuration uses pure solvent reservoir technology (such as the Nsolv process), which precludes the use of steam for bitumen recovery. Consequently, SG and WWT segments are of no significance. However, the process still requires treatment of produced water and energy for solvent heating and purification.

Supply Costs and GHG Emissions

Figure 5.3 shows the impact on supply cost and emissions by the identified optimal technology configurations applicable to green and brown fields.

Figure 5.3: Combined Impact of Technologies under Different Cost and GHG Emissions Scenarios



Source: CERI

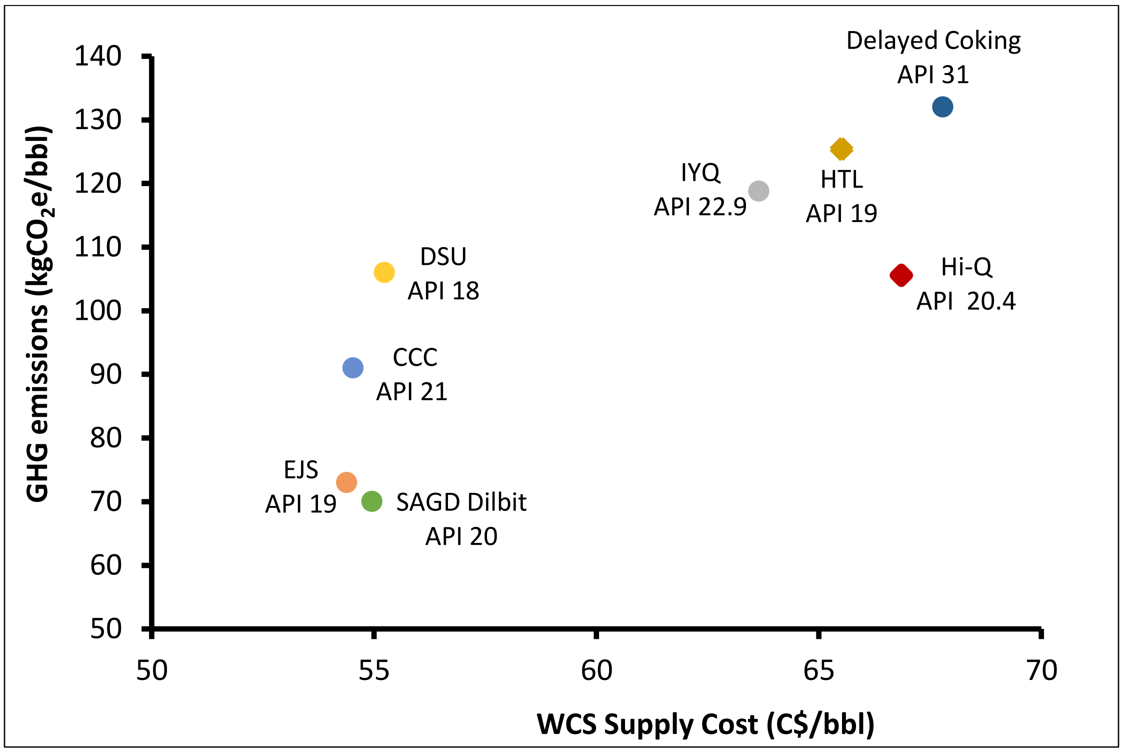
Minimizing cost and GHG emissions are considered as two principal objectives that drive decision making in technology development and commercialization. As shown in Figure 5.3, these objectives lead to a 40 percent (a C$17.40/bbl reduction) and 82 percent (a 50.1 $kgCO_2$/bbl reduction) reduction in bitumen supply costs and direct GHG emissions, respectively, relative to SAGD Base.

As aforementioned, the greenfield developments allow for more flexibility to explore both cost and emissions minimization scenarios. Under the cost minimization objective, two optimal process configurations were identified: steam-solvent extraction, with or without CoGen (SOFC - solid oxide fuel cells). On the other hand, the GHG minimization objective aligns with pure solvent, steam-solvent CoGen, steam-solvent (non-CoGen) technology configurations (Figure 5.3). These three configurations lead to reductions in costs and emissions relative to the base.

Upgrading

Partial or full upgrading are value add components of oil sands processes. A significant share of costs and emissions of oil sands is associated with full or partial upgrading or/and blending. Major promising technologies assessed under this segment are EJS (Enhanced Jetshear) by Fractal Systems, I^YQ (Increased Yield and Quality) by ETX Systems, Hi-Q® by MEG Energy, HTL by Fluid Oil (formerly Ivanhoe Energy), DSU™ by Field Upgrading and CCC by Bayshore Petroleum. These technologies are assessed relative to dilbit (diluted bitumen) and fully upgraded synthetic crude oil (SCO) from delayed coking. On a Western Canadian Select (WCS)-equivalent basis, the supply costs for products from partial or full upgrading technologies are assessed at the facility gate. The product quality is brought to WCS-equivalent by blending with diluent when required. The WCS equivalent assumes a pipeline-ready dilbit with an API gravity of 20. The WCS-eq. supply costs and associated emissions of the products from the partial upgrading technologies are shown in Figure 5.4.

Figure 5.4: GHG Emissions and Supply Cost of Partial and Full Upgrading Technologies



Source: CERI

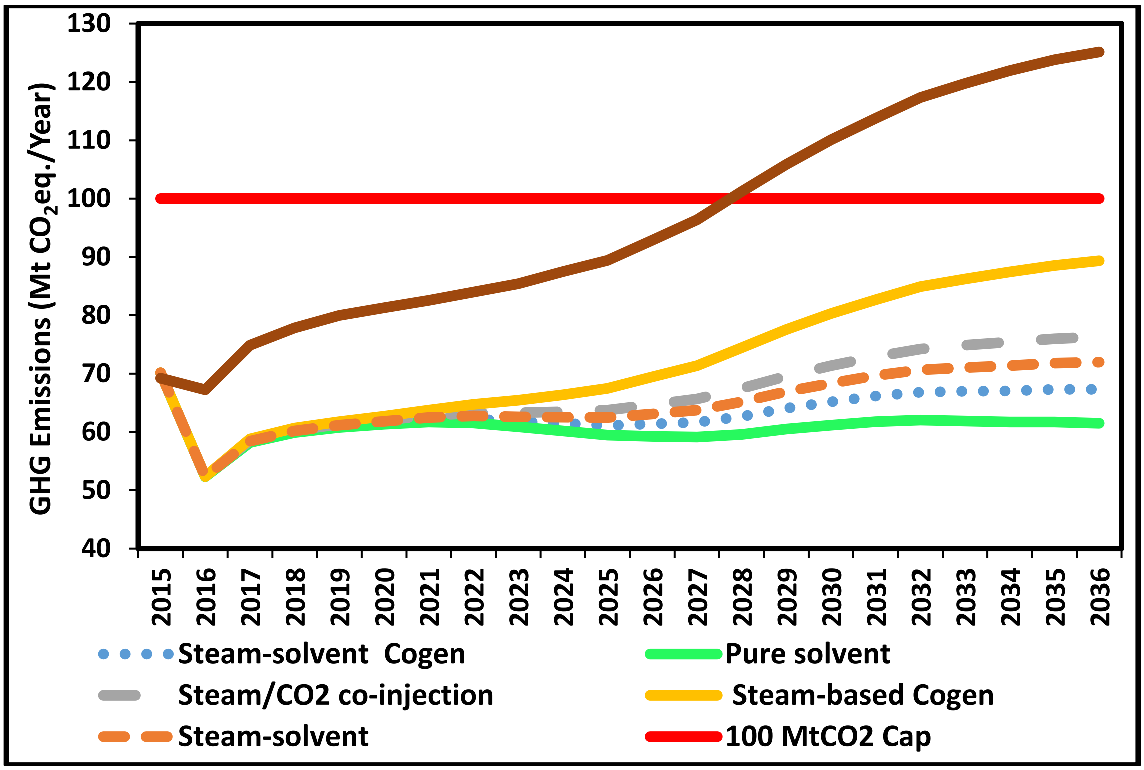
The partial upgrading technologies show potential to add value to bitumen without significantly increasing costs and emissions. However, when brought to West Texas Intermediate (WTI)-equivalent, which is a product that is comparable to the SCO product grade, the supply costs of some of the technologies may not be competitive in a low oil price environment.

Though a supply cost-based assessment of partially upgraded products provides some insights into the economics of the technologies, varying product make-up and characteristics (conversions, distillation fractions, API gravity, total acid number, sulphur content, etc.) make this assessment complex. Thus, a more comprehensive approach would involve an understanding of the money value that the refiners are willing to offer for the value add through partial upgrading. However, such extent of analysis is beyond the scope of this study.

Oil Sands Emissions Profiles and the 100 $MtCO_2$ Emissions Cap

The different technology configurations (in Table 5.1 and Figure 5.3) result in new direct emissions profiles[94] for the oil sands industry and these are compared with the business as usual profile (***BAU with policy changes***[95]***)*** and the ***100 $MtCO_2$ cap*** in Figure 5.5. Under the Climate Leadership Plan,[96] the Government of Alberta legislated (Oil Sands Emissions Limit Act)[97] a hard limit of 100 Mt CO_2eq. per year on oil sands operations to spur efficiency improvements that yield higher productivity with fewer carbon emissions per barrel.

Figure 5.5: GHG Emissions Profile for the Oil Sands Industry and the 100 $MtCO_2$/year Emissions Cap



Source: CERI.

[94] Based on the oil sands production forecast generated in the CERI's 2016 oil sands update.

[95] The profiles in Figure E.5 include current direct and indirect emissions of all the oil sands production methods (mining, in situ, enhanced oil recovery and primary heavy oil production) and upgrading.

[96] Climate Leadership Plan of the Alberta Government. See https://www.alberta.ca/climate-leadership-plan.aspx

[97] Fall 2016 – Bill 26: Oil Sands Emissions Limit Act. Available at https://albertandpcaucus.ca/our-work/project/fall-2016-bill-25-oil-sands-emissions-limit-act

The methane emissions policy of the Alberta Government is also applied. This regulation is part of the Climate Leadership Plan and requires a reduction of methane emissions in oil and gas operations by 45 percent of 2014 levels by 2025.

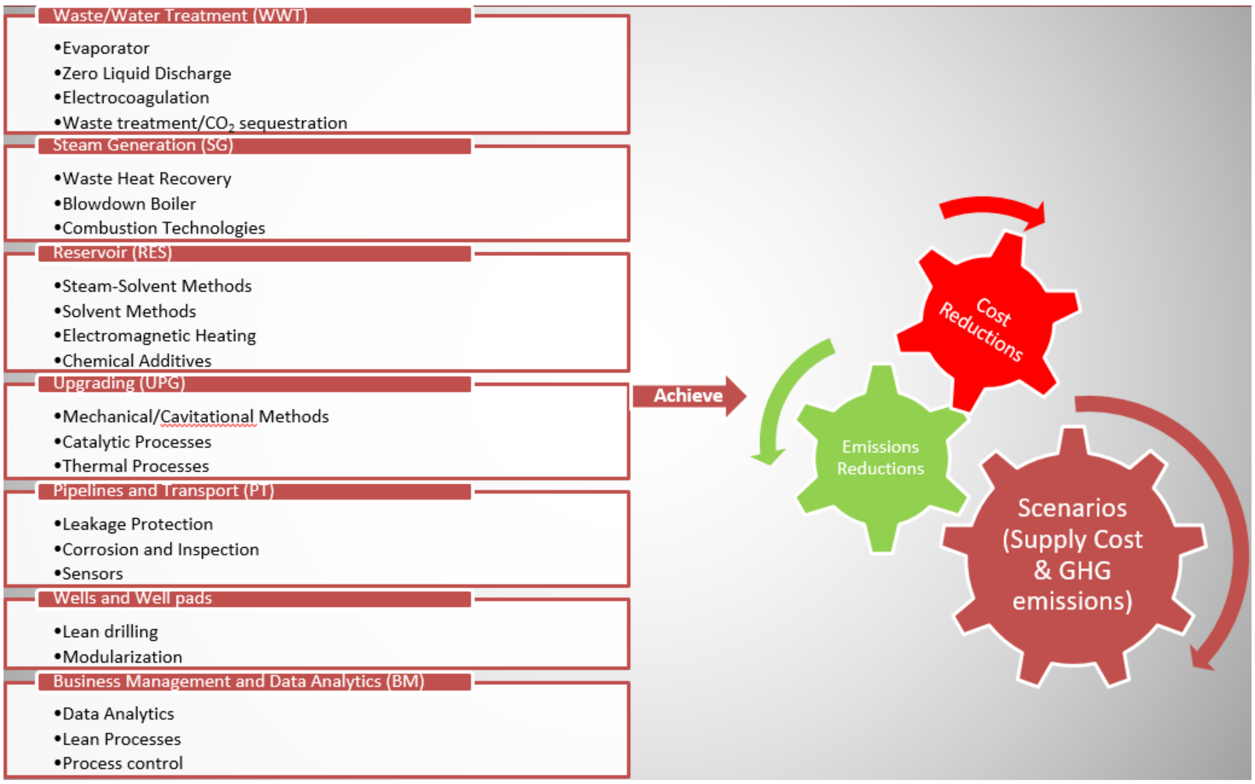
The results show that the ***BAU with policy changes*** profile[98] will reach the 100 Mt CO_2eq. per year cap by 2028. Although a 70.1 MtCO_2 emissions level is observed in 2015, the 2016 wild fires in Fort McMurray, which led to the shutdown of a number oil sands facilities, reduced emissions level to 67.2 MtCO_2 that year.

Over 2015-2036, all the emissions profiles (***BAU with policy changes*** profile and those of the technology configurations) consist of direct and indirect emissions from current mining, in situ, primary recovery and upgrading capacities. However, in accordance with emissions regulation provisions, imported electricity, future cogeneration and upgrading emissions are excluded after 2016. The new GHG emissions profiles[99] based on the optimal cost and emissions technology configurations will allow for oil sands production growth. These technology configurations have the potential to reduce bitumen supply cost by 40 percent, and avoid reaching the 100 Mt CO_2eq. per year cap during the study period (2016-2036).

[98] Included in this profile are the current direct and indirect emissions of all the oil sands production methods (mining, in situ, enhanced oil recovery and primary heavy oil production) and upgrading.
[99] Based on the oil sands production forecast generated in the CERI's 2016 oil sands update.

Appendix – Additional Assumptions and Methodologies

Figure A.1: Different Types of Technologies to be Considered in Each Segment of the Processes



Source: CERI

Theoretical Framework: Economic Theory of Carbon Policy and Innovation

The concept of innovation is a focal point of discussion in climate change debates and plays an important role in developing climate change policy frameworks. Here we analyze how technology innovation plays a central role in fostering a low carbon society without derailing economic growth.

GHG emissions and global warming are positively linked and have an adverse impact on the environment. Also, emissions and economic growth are correlated; therefore, one of the viable policy options is to tax companies' production. This could lead firms to reduce their emissions and/or cut their production.

A heated opposition started among economists known as the Nordhaus–Stern Controversy, based on the estimation of how high the taxation can be and how it can change over time. Nordhaus argued that taxation should be low at the beginning and move up progressively and double every 20 years. This avoids huge shocks on production, but delaying intervention increases short run production and consumption which boosts the economy; however, it may result in future environmental damage.

On the other hand, Stern suggests that we should act now with a heavy carbon tax to avoid future damage, consequently reducing drastically the actual production today. This policy approach would have an immediate negative effect on near-term growth and result in a longer-term downward shift of the overall growth trend of the economy.

The above discussion is based on a model that is unable to adequately integrate innovation in the economic modeling. The analysis of the role of technology innovation in climate change policy is relatively recent in economic literature. Most of the theories and analyses are focused on building scenarios and impact analysis on arbitrary parameters that ignore the drivers of innovation. Some empirical studies have been done and show the link between the pace of innovation and cost paid by consumers in the air conditioning market, as an example. Recently however, a seminal paper[100] proposed a new way to explain how technology innovation may reconcile climate policy and economic growth. This is called the Acemoglu, Aghion, Bursztyn and Hemous (AABH) model.

The key finding of the AABH model is to establish a new paradigm in the conception and application of climate policy based on innovation and carbon taxation at the firm or sectoral levels. For the AABH model, productivity growth is endogenous and takes into account knowledge spillover and complementarities. More importantly, compound effects of innovation do not follow a deviation from a past trend as is the case for previous models.

The AABH climate change and innovation model performs its analysis at the firm level where clean and dirty processes are competing, and firms' researchers are maximizing their profit toward innovating in clean and dirty inputs.

For illustrative purposes, let us examine the implication of the AABH model to oil sands extraction processes. We can consider the SAGD base case (high GHG emissions but well-developed, and economically viable process) and a pure solvent-based process (low GHG emissions, under development and not yet commercially viable) as using dirty and clean inputs, respectively. Assume that Company A and Company B compete by developing innovations that maximize profit on technologies that use the dirty and clean inputs, respectively.

Company A has a higher competitive advantage because it uses a mature and profitable process and will invest in improvements of the high emissions process. On the other hand, Company B has less competitive advantage because it is investing in a low emissions process that is riskier due to technology maturity level.

[100] Acemoglu, D., Aghion, P., Bursztyn, L. and Hemous, D., 2012. The environment and directed technical change. The American Economic Review, 102(1), 131-166.

Without a proper climate policy, Company A outcompetes Company B in the market. An AABH-backed policy requires a subsidy to Company B and a carbon tax on the economy. This policy supports clean innovations as well as technology diffusion.

The AABH necessitates that the subsidy be transitory and transition to a lower carbon economy should be made as quickly as possible. For our case, if a pure solvent-based method is not feasible in a reasonable timeframe, solvent-steam methodology, which can be considered as an intermediate option between the dirty (SAGD base case) and cleaner (pure solvent method) might become a transitory process before a cleaner method reaches its full potential. To avoid getting locked into the solvent-steam process (transitory technology), research in cleaner technologies would need to be stepped up.

The innovation policy will need public and private sector involvement (private market forces need to be mobilized and directed toward cleaner technologies). An optimal output is reached if public policy is transparent, non-discriminatory and avoids industry capture.

Companies are subject to path dependence, where firms may be locked into innovating in dirty goods. Path dependence is a common phenomenon in socioeconomic systems, which arises when initial conditions and their historical antecedents influence eventual outcomes.[101] Path dependence might push companies to lobby for a less restrictive regulation, generating inertia as a result of that.

In the following section, we relate the AABH model to the Alberta innovation ecosystem and how it can provide enough technologies to fuel greener and cost competitive oil sands extraction.

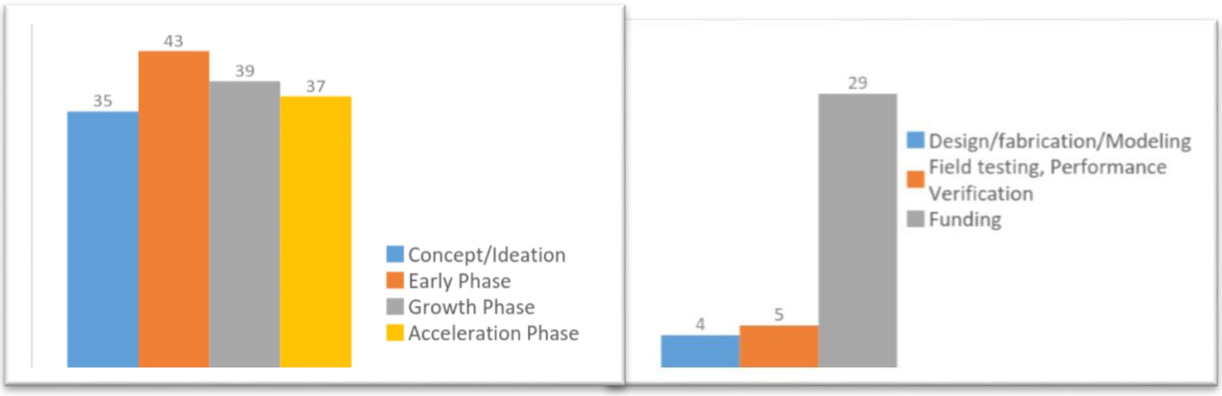
Alberta Innovation Ecosystem

The goal in this section is to look at how institutions are organized to support an efficient innovation ecosystem that delivers technologies able to mitigate climate change. The primary objective of the innovation ecosystem, which is technologically directed towards climate policy, is to promote the development of clean technologies, their adoption, spillover of knowledge and emerging complementarities between products and technologies. In another sense, policy makers need to set a policy that shifts people’s expectations and changes the initial conditions (funding clean technology research or infrastructure) to de-risk technologies.

A repository developed by AlbertaIN (an online directory) shows a variety of organizations and services an entrepreneur can get in Alberta. About 65 private (non-investors), not-for-profit and public organizations are positioned along of product development. About 77 percent of the organizations can provide services linked to energy innovation and GHG emissions reduction.

[101] Acemoglu, D., Aghion, P., Bursztyn, L. and Hemous, D., 2012. The environment and directed technical change. The American Economic Review, 102(1), 131-166.

Figure A.2: Organizations Involved in the Innovation Ecosystem in Alberta



Source: CERI

Seen from an economics point of view, the multitude of players might create competition and help any entrepreneur/innovator to find a best fit. In reality, the inventor finds it hard to navigate through this jungle and may perceive it as a waste of time. As shown in Figure A2, only a few organizations can deliver key services, such as prototyping and field testing, which are critical to the success of oil sands technology development. Even though 29 organizations in Alberta claim to support innovators in research and development funding, only about 5 of them provide direct funding whereas the rest help in networking to find partners and investors.

For those who support innovators through funding, most of the grants are not significant for early stages such as proof of an idea or concept before the acceleration phase. The stages preceding the acceleration phase are the riskiest part of the innovation journey and require greater support.

These organizations are relevant for independent inventors, but for private, well-established companies who have enormous resources and knowledge to develop clean technologies, they do not need the ecosystem as much as the small and independent innovators do. However, most of the well-established companies are locked in a path dependence innovation system where projects that improve production and help meet new regulations get approved easier than those cleaner substituting alternatives.

A major part of the Alberta Innovation ecosystem is the Canadian Oil Sands Innovation Industry Alliance (COSIA). As of November 2016, partners and associate members have shared 936 distinct technologies and innovations that cost nearly $1.33B to develop. COSIA has made promising first steps but it is still considered by some to be slow, and the organization is not immune to competition among its partners. The direct link between environmental performance and production make this collaboration challenging and ineffective in some ways. Although COSIA members aim to collaborate in accelerating improvement in the oil sands industry's environmental performance, they acknowledge that they are competitors in all respects. No company wants to share information or technology that will reduce its competitive edge. Therefore, the collaboration in COSIA can be considered suboptimal equilibrium.

Provincial and national governments play a key role in innovation. When formulating innovation policies, the government needs to be aware that directed technical change is exposed to dynamic market failures and can potentially amplify the resistance to change. Helm (2012)[102] shows how the government picking winners and losers makes the cost of change to a lower carbon economy substantial. Picking of winners locks the system in new path dependence based on the favored innovation. The challenge for policy makers is to design a market-based innovation policy that is transparent and non-discriminatory against any innovative approach. This means that the policy makers should be technology-neutral.

In an early stage of technology development when investors and private companies are highly risk-averse to fund technology development, provision of funding to public research institutes or universities for basic and early-stage research by the government can drive innovation. In the past, public research institutes have had remarkable success in innovation; an example is AOSTRA, which was critical in the development of in situ SAGD bitumen recovery. However, a recent presentation by Swedish economist, Thomas Sterner at College de France[103] shows that a flow of funding for green technology in universities ended up with more paper publications rather than true technologies development.

In a market-driven innovation ecosystem, the most challenging issue is how to allocate the public funds properly; the actual process has been based mostly on grant applications. The grant application process is not able to capture an optimal degree of newness because experts tend to be overcritical of novel ideas proposed in their own domain.

For example, a Harvard and NorthWestern University study shows that the most novel proposals or research projects get worse ratings than familiar projects.[104] Indeed, the grant application process might reject audacious projects even though they might have a greater impact because they are screened by experts in their area. Consequently, some novel and potentially disruptive concepts don't receive public funding and may not have a chance to be implemented. This leads to a suboptimal use of public funds.

There is a gap between industry and public research agendas, independent innovators and universities believe that industry should be keener to test new technologies, and industry on the other side, are of the view that public and independent innovators should address the right problems.

Recently, new players have come on board to seek to close this gap to bring all the stakeholders together for increased innovation effectiveness in the energy industry. Two examples of these are Kinetica Ventures and Newwavo. Kinetica Ventures is an accelerator in Innovate Calgary focusing on de-risking new energy technologies. Kinetica Ventures grand challenge bridges the

[102] Helm, D., 2012. The Carbon Crunch: How We're Getting Climate Change Wrong – and How to Fix It. London: Yale University Press.
[103] College de France, Développement durable – Environnement, énergie et société (2015-2016)
[104] Lakhani, L., 2014. Looking across and looking beyond the knowledge frontier: intellectual distance, Novelty, and resource allocation in science. INFORMS 2014.

gap between the energy companies and technology innovators by identifying the most pressing challenges in four areas: hydrocarbon recovery; energy transport; carbon capture, re-use and disposal; and renewable energy. They provide access to capital, expertise and relationships to commercialize industry-validated technologies more efficiently and cost effectively, and achieve faster adoption by energy sector partners.

Newwavo is a consulting company seeking to fill a gap in new technology field trials, where interoperability with existing field technology, and integration with business activities, IT, and databases, might be challenging for independent innovators. Newwavo assembles multidisciplinary technical advisors and operational change experts to help independent innovators control target conditions and plan and execute field trials in an optimal way.

CAPEX and OPEX

When necessary, the six-tenths rule was used for equipment or plant capacity scale-up or scale-down. The six-tenths rule is given as:

$$c_1 = c_2 \left(\frac{S_1}{S_2}\right)^n$$

where c_1 and c_2 are the unknown and reference CAPEX of equipment (or plants) 1 and 2, respectively, S_1 and S_2 are the known sizes of equipment 1 and 2, respectively, and the exponent n is a constant. Here n = 0.6. The six-tenths rule is only applied where the equipment is similar in characteristics. For more information about this rule, the reader may refer to Peters et al.[105]

[105] Peters, M.S., Timmerhaus, K.D., West, R.E., Timmerhaus, K. and West, R., 1968. Plant design and economics for chemical engineers (Vol. 4). New York: McGraw-Hill.

SAGD Base Case Capital Cost

Table A.1: SAGD Base Case CAPEX Details

Case Description	Units	CAPEX
Drilling and Production		
Production		
Drilling & completion (includes EPCM & Cont.)	$M	116.55
Production Pumps (TIC)	$M	30.35
Total Drilling and Production-SAGD	**$M**	**146.90**
Core Facility (ISBL)		
Well Pads		
Well Pads	$M	76.48
Gathering lines/Pipelines	$M	50.99
Central Processing & Water treatment		
Oil treating	$M	39.46
De-oiling	$M	23.67
Warm line softeners	$M	49.17
Raw water/Disposal Treatment	$M	2.43
Steam Generation		
OTSG	$M	72.8
Sulphur Treating Blocks	$M	8.50
Total Construction Indirect and others costs	$M	135.97
Total ISBL-SAGD	$M	**459.52**
Offsite CAPEX (Line items & Factored costs)		
Storage and pipeline		
Utilities & Main Rack	$M	78.91
Products Storage	$M	13.35
CPF Infrastructure	$M	15.78
Connecting Pipelines	$M	60.70
Road and Infrastructure Improvement	$M	7.28
Non-process Buildings	$M	5.46
Total OSBL-SAGD	**$M**	**181.50**
Others costs		
Home Office and Engineering Services		
EPCM costs – Pads and Gathering lines	$M	9.11
EPCM costs – CPF	$M	61.92
Total EPCM Costs	$M	**70.41**
Owners Cost		
Owner Costs (% of TIC)	$M	47.35
Logistics (% of TIC)	$M	15.78
Startup (% of TIC)	$M	15.78
Capital Spares (% of TIC)	$M	7.89

Catalyst and Chemicals (% of TIC)	$M	7.89
Camp Operations	$M	30.35
Land (assumed = 0)	$M	
SAGD Total "Others Costs"	$M	**125.05**
Totals		
Drilling and Production (subsurface)	$M	146.90
SAGD surface facilities	$M	836.48
Contingency		
SAGD Contingency Percentage (excl. sub-surface)	%	15
SAGD Contingency (excl. sub-surface)	$M	209.42
Total Installed Cost (TIC) with contingency		
Total Drilling and Completions	$M	146.90
Total SAGD surface facilities	$M	1045.90
Total Installed Cost (TIC) with contingency	$M	**1192.80**

Source: CERI

SAGD Base Case Operating Cost

Table A.2: SAGD Base Case OPEX Details

Case Description	Units	OPEX
Variable Costs		
Power	$/MWh	33
Natural gas	$/GJ	2.08
Water treatment chemicals	$M/Yr	5.1
Oil treatment chemicals	$M/Yr	4.5
Carbon Emission Costs @ $15/MT	$/tons	15
Land Fill Costs @ $44.1 /MT	$M/Yr	1.0
Fixed Costs (per location)		
Maintenance of production pumps	$M/Yr	9.6
Maintenance supply	$M/Yr	43.7
Insurance and regulatory fees	$M/Yr	3.7
Staffing	$M/Yr	14.5
Total "Fixed Costs"	$M/Yr	70.6

Source: CERI

Bitumen Upgrader (Delayed Coker) CAPEX

Table A.3: Bitumen Upgrader (Delayed Coker) Capital Cost (2015 Values)

Case Description	Units	Cost
Purchased		
Athabasca Bitumen	bbl/day	30,000
Natural Gas	GJ/hr	826.65
Power	MWhr	15
Products Generated		
30-32 API SCO	bbl/day	26,500
Sulfur	Tons/day	168.3
Coke	Tons/day	37.35
CAPEX		
Diluent Recovery unit	$M	102.3
Vacuum Distillation Unit	$M	72.6
Coker	$M	303.7
Naphtha Hydrotreater	$M	16.5
Diesel Hydrotreater	$M	42.9
Mild Hydro Cracker	$M	320.2
Hydrogen Plant	$M	105.6
sulfur Plant	$M	56.1
Air Separation Unit	$M	-
Total ISBL	**$M**	**1020.0**
Offsite	$M	617.3
contingency	$M	165.0
Total Installed Costs	**$M**	**1802.3**

Source: CERI

Bitumen Upgrader (Delayed Coker) Operating Cost

Table A.4: Bitumen Upgrader (Delayed Coker) Operating Cost (2015 Values)

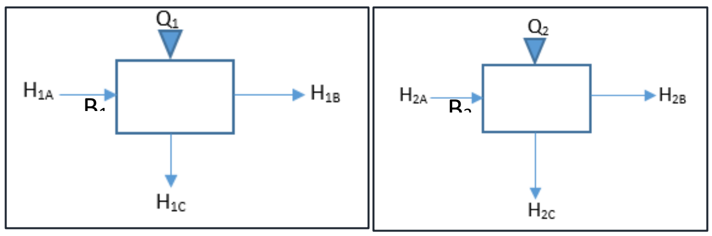
Case Description		Units	Cost
Basis Data			
Athabasca Bitumen		bbl/day	30,000
Natural gas		GJ/hr	826.65
Natural gas imports		MW	229.65
Power imports		MW	15
Total energy imports		**MW**	**244.5**
Variable Expenses			
Natural Gas		$/GJ	2.07
Power imports		$/MWh	$33
Cat & Chem Costs (1.5% ISBL)		Mil $/ YR	$47.0
Total Variable expenses		Mil $/ YR	$288.9
Fixed Expenses	4.5% of TIC	Mil $/ YR	$81.1

Source: CERI

Steam Generation Segment

Calculation of the Impact of Efficiency Improvement on the OPEX (fuel use) of a Boiler

Consider two steam generators B_1 and B_2 which have efficiencies E_1 and E_2, where $E_2 > E_1$. As shown in the figure below, corresponding heating rates are Q_1 and Q_2. If both systems must satisfy the same steam load required at the same conditions, then we can obtain the enthalpies of streams H_{1B}, H_{1C}, H_{2B}, and H_{2C} from steam tables for the saturated steam (H_{1B}, H_{2B}) and water (H_{1C}, H_{2C}) at the requirement conditions.



The savings in heating requirement – which is the net of Q_1 and Q_2 – amounts to the difference in fuel costs (OPEX) between the two boilers.

$$E_1 = \frac{H_{1B}}{Q_1 + H_{1A}}, \qquad E_2 = \frac{H_{2B}}{Q_2 + H_{2A}}$$

Often, only the heat rate of one boiler might be known. In that case, we use the knowledge that streams H_{1B} and H_{2B} have the same specific enthalpy, and streams H_{1A} and H_{2A} can be assumed to have the same specific enthalpy since they are coming from the same process. Therefore, (if Q_2 is known) Q_1 can be calculated from the overall energy balance around boiler B_1.

Water/Wastewater Treatment Segment

Producing carbonic acid for in situ magnesium precipitation

$H^+ + OH^- + CO_2 \rightarrow H^+ + HCO_3^-$

Precipitating the dissolved magnesium with slaked lime

$Mg^{2+} + H^+ + 2HCO_3^- + 2Ca(OH)_2 \rightarrow 2CaCO_3 + \mathbf{Mg(OH)_2} + 2H_2O + H^+$

Since in situ Mg requires basic pH to precipitate out, a base must be added to remove the hydrogen ions. Carbon dioxide requirement is calculated using the above equations. The cost of capturing this CO_2 is also included in order to find the net impact on the operating cost if in situ magnesium is to be used.

Reservoir Segment

Solvent-Based Processes. The costs and emissions parameters of solvent-based technologies are highly sensitive to the recoverability of the solvents both in surface and sub-surface facilities. However, it seems that solvent lost in a commercial surface facility can be recovered and used as fuel gas to reheat solvent for injection. This is a benefit that minimizes energy and cost penalty. On the other hand, using the recovered solvent as a fuel is not an optimal use of a high premium solvent. Solvent that is not ultimately recovered sub-surface is reflected in operating cost and indirect GHG emissions of solvent supply. Note that part of the unrecovered solvent may be entrained in the oil. This study does not take into account fugitive emissions and environmental impacts of the solvents that may be trapped in reservoirs after remediation.

Here are other highlights of the solvent-based processes. The presence of some of the unrecovered solvent in the bitumen may reduce the viscosity of the bitumen, thus improving its pipeline transport quality. The simplicity of the process and a major reduction in the amount of rotating equipment may lead to a significantly lower CAPEX and a quieter operation than a SAGD operation. In addition, due to the low temperature operation, odors associated with the generation of H_2S are almost non-existent. Also, the solvent-based process has the prospect of low pressure operations, which minimizes the risk of cap rock breach and allows recovery of shallow resources that are inaccessible by traditional SAGD.

Solvent-Steam Processes. Major considerations include that solvent price increase leads to low profitability. Solvent retention in the reservoir is an important factor to consider. Retention of solvent is estimated at about 2 percent or less. The cost of solvent retained in the reservoir either dynamically, as a running inventory, or ultimately, after final solvent scavenging, is an important setback of the process. Solvent recovery factor is expected to be around 70-90 percent.[106] Butane recovery factor was reported to be 64 percent.[107]

Electromagnetic Heating Processes. The prospects and setbacks of the EM method are highlighted herein. The EM heating method is beneficial in many ways:[108]

- EM makes it efficient to work in shallow wells where other aqueous thermal methods like steam injection cannot work.
- EM does not require a large water supply like SAGD.

[106] Ardali, M., Barrufet, M., Mamora, D.D. and Qiu, F., 2012, January. A critical review of hybrid steam/solvent processes for the recovery of heavy oil and bitumen. In SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.
[107] Gupta, S., Gittins, S., Benzvi, A., Dragani, J., 2015b. Feasibility of Wider Well Spacing With Solvent Aided Process: A Field Test Based Investigation, in: SPE-174411-MS. Society of Petroleum Engineers, SPE. doi:10.2118/174411-MS
[108] Bera, A. and Babadagli, T., 2015. Status of electromagnetic heating for enhanced heavy oil/bitumen recovery and future prospects: A review. Applied Energy, 151, 206-226.

- EM can be applied to heterogeneous reservoirs even in the high permeability zones or fractured area.
- Heat loss can be reduced by the controlled use of the EM heating process; thus, it can be more energetically efficient.
- EM could result in less GHG emissions than the typical SAGD process.

The EM heating methods are faced with a number of issues, including:

- EM is limited to near-well bore heating preferably applied to vertical wells.
- Electrode corrosion concerns in the case of a high salinity reservoir render this technique uneconomic.
- EM wave penetration depth is low for high frequency radiation; this leads to a reduced area that is heated.
- Possible adverse impacts of EM heating on the environmental ecosystem, microorganisms and biological balance.[109]

Others

Steam-surfactant process. The major benefits of the steam-surfactant process can be narrowed down to marginal reductions in energy intensity, greenhouse gas emissions and oil production uplift. However, this technology faces some setbacks that delay its commercial implementation. These include difficulty in recovering solvents lost in the reservoir and the presence of interactions with clay materials in the reservoir.[110] Also, surfactants can be absorbed in the rock and may be difficult to recover. Treatment and disposal of emulsions are important concerns.[110] A mixture of surfactants with water forms stable emulsions, which can be energy-intensive to break by heating. However, the use of coagulants offers a less energy-intensive alternative, but at a cost for the coagulants. Surfactants are expensive. Thus, alkalis such as sodium hydroxide, sodium carbonate and sodium orthosilicate are combined with surfactants due to their lower costs.[111] There could be possible damage of the oil reservoirs by insoluble residues left by the surfactant-based formulations, with obvious environmental impacts.[112]

[109] Bera, A. and Babadagli, T., 2015. Status of electromagnetic heating for enhanced heavy oil/bitumen recovery and future prospects: A review. Applied Energy, 151, 206-226.
[110] Shah, A., Fishwick, R., Wood, J., Leeke, G., Rigby, S. and Greaves, M., 2010. A review of novel techniques for heavy oil and bitumen extraction and upgrading. Energy & Environmental Science, 3(6), 700-714.
[111] Galas, C., Clements, A., Elden J., Jeje, O., Holst, D., Holst, R., 2012. Identification of enhanced oil recovery potential in Alberta. Phase 2 Final Report for Energy Resources Conservation Board. Sproule Associates Limited, Calgary.
[112] Gurgel, A., Moura, M., Dantas, T.N.C., Neto, E.B., Neto, A.D., 2008. A review on chemical flooding methods applied in enhanced oil recovery. Brazilian Journal of Petroleum and Gas 2.

SEGD Process. The process has the following advantages:

- precludes surface steam generation facilities
- reduces associated greenhouse gas emissions
- eliminates costly steam distribution pipelines
- reduces the complexity of water treatment and the use of makeup water
- Reduces the amount of rejected water disposed and the need for a sulfur recovery plant.

A major challenge that this technology will face will be difficulty in maintaining steady combustion, avoiding burnout and explosion, and controlling mass and heat transfer in the reservoir.

Optimal Technology Adoption

Three case studies of technology adoption are considered including the base SAGD facility and two optimal technology adoption scenarios based on economic and environmental objectives. The economic adoption case aims to develop a facility configuration with the minimum discounted CAPEX and OPEX. The environmental adoption criterion assembles a production facility with minimum emissions intensity.

Optimal economic technology selection: for a technology i deployed in segment j in year k, the selection objective is formulated as follows:

$$\min_{y_{ij},c_{ijk}} \sum_k \sum_j \sum_i y_{ij} c_{ijk} b_k$$

$subject\ to$:

$$\sum_k b_k \leq B$$

$$\sum_k \sum_i c_{ijk} \leq C_j \qquad \forall j \in J$$

$$\sum_k \sum_j \sum_i e_{ijk} b_k + e_m d \leq E_c$$

$$\sum_{i \in M_j^s} y_{ij} = 1 \quad \forall j \in J$$

$$\sum_{i \in M_j^c} y_{ij} \geq 1 \quad \forall j \in J$$

$$y \in [0,1], c, b, e, C, B, E \geq 0$$

- Optimal environmental technology selection

$$\min_{y_{ij},e_{ijk}} \sum_k \sum_j \sum_i y_{ij} e_{ijk} b_k$$

$subject\ to$:

$$\sum_k b_k \leq B$$

$$\sum_k \sum_i c_{ijk} \leq C_j \qquad \forall j \in J$$

$$\sum_k \sum_j \sum_i e_{ijk} b_k + e_m d \leq E_c$$

$$\sum_{i \in M_j^s} y_{ij} = 1 \quad \forall j \in J$$

$$\sum_{i \in M_j^c} y_{ij} \geq 1 \quad \forall j \in J$$

$$y \in [0,1], c, b, e, C, B, E \geq 0$$

c – Cost (discounted CAPEX and OPEX)

C_j – Cost of segment j in the base case

b – In situ bitumen production

d – Mined bitumen production

B – Ultimate bitumen recovery from all wells

y – Binary variable for technology selection

e – Emission intensity

E_c – Emissions cap on the oil sands industry

M_j^c – Set of complementary technologies deployable in segment j

M_j^s – Set of non-complementary technologies deployable in segment j

Each technology is characterized by the cost and emission intensity. These two variables distinguish the objective functions for the optimal adoption scenarios. The set of constraint equations capture the production capacity, the financial investment in the facility, Alberta's emissions cap policy on the oil sands, and the deployability of any of the technologies in consideration.

Upgrading Segment

EJS. This technology brings a main benefit of pipeline infrastructure debottlenecking through diluent reduction. The volume released by removing diluent from the system would allow increases in bitumen production. The diluent demand in the province is expected to increase in the future; thus, by reducing the diluent required to meet pipeline specification there is less need for increased diluent pipelines from the US. Improved oil sands operating margins can be achieved through diluent avoidance of up to 50-60 percent. Assuming 2015 prices and 55 percent diluent avoidance, operating cash margins can be improved by about $4/bbl.

To achieve the same refined product volumes as the EJS, additional dilbit is required in the Base Case, where the product is transported via pipelines. The ClimateCHECK's study reports that up to 11 kgCO_2/bbl of GHG intensity reduction can be achieved by the EJS process; this is a 5 percent reduction from dilbit transported by pipeline.

CCC. The CCC produces natural gas, diesel and petroleum coke, thus the viability of the technology would be dependent on the demand and price of diesel. Thus, the process is not a replacement for refineries which produce predominantly gasoline.

I^{Y}Q. Table A.5 shows the composition of the products from generated from I^{Y}Q upgrading of dilbit.

Table A.5: Yields from Bitumen and Dilbit Upgrading using the I^{Y}Q Process

		I^{Y}Q Upgrading	
	Dilbit	Yield / bbl Bitumen	Yield / bbl Dilbit
Diluent, %	30	-	30
Bitumen, %	70	-	-
VGO & Distillate (200-524°C), %		80	56
C_5+ (to 200°C), %		8	5.6
offgas (C_2-C_4), %		8	5.6
Sulfur, kg/bbl		1.8	1.26
Coke, kg/bbl		25.1	17.57

Source: CERI

Hi-Q. The advantages of this process are listed by Svrcek et al.[113] to include:

1) Use of two known commercial technologies: mild, controlled thermal cracking and high performance solvent de-asphalting

[113] Svrcek, B., Flint, L., Remesat, D., Penner, R., Guo, J., 2016. Partial Upgrading Background Review "White Paper" In Support of The National Partial Upgrading Program (NPUP) (No. AI-EES Contract #2280).

2) Optimization of the thermal cracking process to crack heavy molecules with reduced generation of non-condensable gases and coke in the reactor

3) Solvent de-asphalting process that separates by solid precipitation the hard to convert asphaltene molecule (into motor transportation fuels) while retaining nearly all the resins as crude product

4) Low hydrogen requirements targeting the generating olefins while minimizing sulfur and nitrogen removal

5) Use of diluent to serve as solvent, and

6) Low solvent to oil ratio of 4-5:1 wt. basis.

However, the production of solid asphaltene product in large quantities that may flood the market and require a disposal method is viewed as a major challenge.[113]

Empirical Correlation for Estimating Upgrading OPEX

An empirical correlation for estimating the operating costs of partial upgrading given the API gravity of raw bitumen or heavy oil and the API of the upgraded oil was formulated. Upgrading entails the breaking of long chain hydrocarbon bonds into smaller chain hydrocarbons, a process that is energy-intensive. The energy for this process is provided for thermal cracking or as hydrogen for hydrotreating. It is reasonable to assume that the energy requirements of partial upgrading of heavy crude (with a specified API gravity) to an upgraded product (with a specific API gravity) significantly impacts the OPEX associated with partial upgrading. Thus, we explored a correlation of increases in API gravity (ΔAPI) achieved through upgrading with the operating cost requirement using peer-reviewed published data.

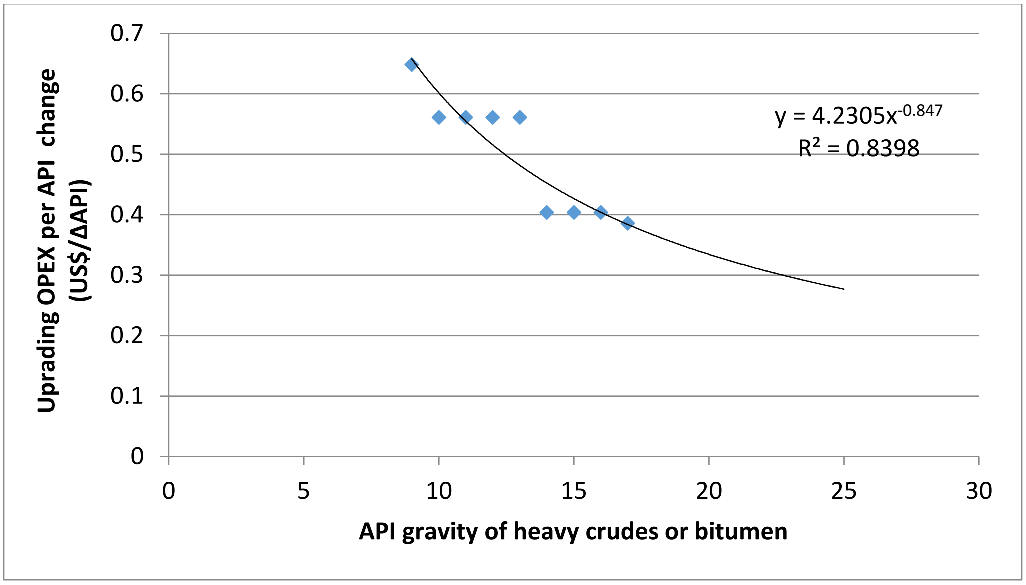
Table A.6: OPEX Requirements for Select Upgrading Technologies for Heavy Oil or Bitumen

	API(1)	API(2)	Ave. OPEX	$/ΔAPI
IMP	9	13	3.4	0.85
Viscositor	7	16	3.8	0.42
HTL	10	17	2.7	0.39
ENI	18	25	5.2	0.74

Source: Calculated from Castañeda et al[114]

[114] Castañeda, L.C., Muñoz, J.A.D., Ancheyta, J., 2014. Current situation of emerging technologies for upgrading of heavy oils. Catalysis Today 220–222, 248–273. doi: http://dx.doi.org/10.1016/j.cattod.2013.05.016

Figure A.3: API Gravity Correlation with OPEX



Source: CERI

Applying the OPEX requirements per change in API gravity ($/ΔAPI values) obtained across the range of API gravity each upgrading technologies operates, and then estimating the average of the $/ΔAPI values, we obtain a power correlation between the $/ΔAPI values and API gravity as shown in Figure A.3.

The correlation shown in Figure A.3 conforms to an *a priori* fact that the OPEX required for specified reduction in the API gravity of heavy oil or bitumen reduces as the API gravity of the un-upgraded raw material increases. Thus, the higher the viscosity of the un-upgraded heavy oil or bitumen the lower the upgrading OPEX requirements.

A power correlation equation is obtained as:

$$y = 4.2305x^{-0.847}$$

where y is the OPEX per unit API gravity increase resulting from upgrading whereas x is the API gravity of the oil.

Using the correlation, the OPEX associated with upgrading heavy oil or bitumen by a specified reduction in API gravity can be estimated. For example, the OPEX for upgrading bitumen from an API gravity of 9 to upgraded oil with an API gravity of 24 is demonstrated. This case requires a 14-point increase in the API gravity. Calculating the difference in upgrading OPEX per unit change in API gravity (US$/ΔAPI) measured at the API gravities of 9 and 24 and multiplying that with 14 (ΔAPI) gives the upgrading OPEX requirements. The result obtained for this case is US$5.05. Similarly, partially upgrading heavy oil with an API gravity of 9 to a partially upgraded product with an API gravity of 17 requires an OPEX of US$2.19 (Table A.7).

Table A.7: Upgrading OPEX as a Function of API Gravity

API gravity	9	10	11	12	13	14	15	16	17
IMP ($/ΔAPI)	0.85	0.85	0.85	0.85	0.85				
Viscositor ($/ΔAPI)	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	
HTL ($/ΔAPI)		0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Average ($/ΔAPI)	**0.64**	**0.55**	**0.55**	**0.55**	**0.55**	**0.40**	**0.40**	**0.40**	**0.39**

Source: CERI

Pipelines and Transport (PT) Segment

Armadillo is a pipeline inspection gauge (PIG) tracking technology of PureHM Inc. The Armadillo remote and automated pig tracking and benchmarking technology was developed to make tracking pipeline pigs safer and better for the environment. It can be applied for all purpose pig tracking in any type of environment. The Armadillo technology incorporates an innovative above ground marker (AGM) for inline inspection (ILI or smart pigging) and uses a web page to display the pig position, velocity and estimated time of arrival in real time. The Armadillo AGM incorporates six sensors to detect electromagnetic, magnetic and acoustic emissions from the pig.

The Armadillo Remote Tracking Unit (RTU) combines an Armadillo AGM with cellular and/or satellite modems, allowing PureHM Inc. to monitor the AGM remotely through the internet. This allows pre-deployment of Armadillo RTUs at remote pig tracking sites to reduce the hazards and risks associated with conventional tracking.

Table A.8: Safety and Efficiency Parameters of the Armadillo Remote Tracking Innovation Compared with the Conventional Tracking Method

Item	Conventional Tracking	Remote Tracking Innovation	% Reduction
Number of Field Technology	6	1	83.3
Number of 4x4 vehicle days	25 days	6 days	76.0
Number of KM's driving in a truck	6,247 km	2,575 km	58.8
Number of hours worked after 10 pm	106 hrs	0 hrs	100
Field Technician Time	302 hrs	130 hrs	59.4
Subsistence	13 days	3 days	76.9

Source: PureHM Inc and Enbridge.

The Armadillo remote tracking service reduces the number of personnel and vehicles travelling along the pipeline right of way to track the pig. This saves money while improving reliability, increasing safety, while also reducing environmental impacts. The benefits that this technology has over the conventional pig tracking methods have been assessed and tabulated in Table A.8.

Spectrum XLI

The Spectrum XLI is also an innovation of the PureHM Inc. This technology is an above ground inspection system for buried pipelines, offering a consolidated solution for mapping and inspection techniques, and many of these can be done in a single pass over the pipeline. The Spectrum XLI is a configuration of solutions that include the integration of multiple survey systems in one pass, and the software solutions allow for state-of-the-art processing and management of data collection. The Spectrum XLI system is a unique survey instrument designed to meet the needs of industry for the indirect inspection of pipelines, as part of External Corrosion Direct Assessment (ECDA) programs. ECDA Programs include: Depth of Cover, Leak Surveys, Depth of Water, Coating Survey – ACVG /ACCA, Cathodic Protection, and Corrosion Potential Survey – DCVG.

Price comparison for Spectrum XLI depends on the number of inspection techniques being used. Spectrum XLI can do as many as 10 inspections in one pass. Some assumptions can be made about other technologies and the number of crews, and specialized equipment operators needed if all 10 inspections were to be made using the legacy technologies. Here are some standard pricing numbers for comparison of Spectrum XLI with legacy technologies:

1) Depth of cover inspection – $300/mile
2) GPS / GIS mapping – $500/mile
3) Cathodic protection close interval (CP CIPS) – $800/mile
4) DCVG – $500-$1,000/mile
5) ACVG – $500-$1,000/mile
6) ACCA – $600/mile
7) Leak Detection – $100/mile
8) Soil resistivity – $100/mile
9) Water Crossing (SONAR & DOC) – $3,000/mile
10) AC Pipe to Soil Potential – $500/mile

The total amount for legacy technologies to do all the above is $3,900/mile excluding water crossings which are only done on river and creek crossings. However, the integrated Spectrum XLI inspections with all 9 inspections in one pass would cost $1,500 - $3,000/mile. The data would be correlated and immediately ready for analysis once the field data collection was completed. The 9 individual legacy inspections would need to be correlated and aligned prior to analysis, which is a time consuming and expensive process.

SmartBall®

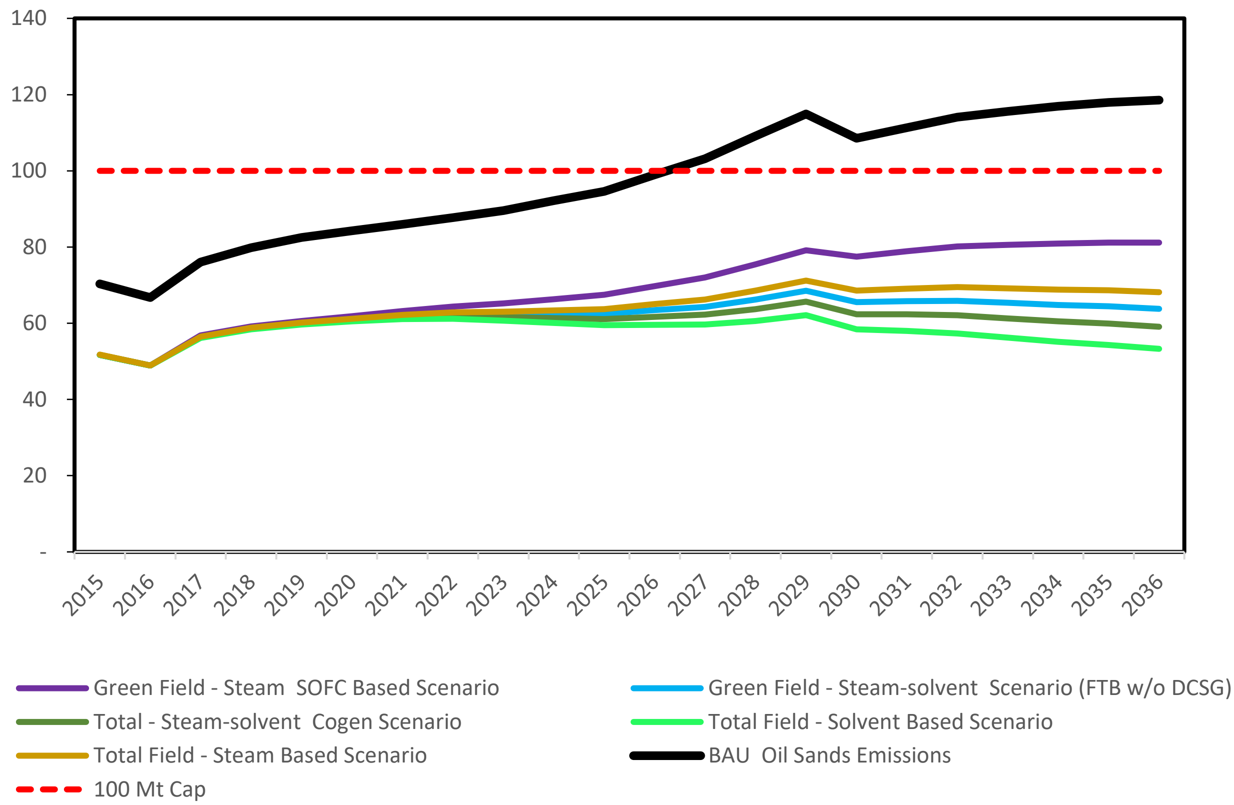
The SmartBall® is a new innovative leak detection technology for oil, gas and petroleum product pipelines larger than 4-inch (100 mm) diameter. It is a product of PureHM Inc. and can be applied for the following purposes: 1) to complement existing pipeline integrity programs or 2) to check the integrity of non-piggable lines. The SmartBall is made up of an instrumented aluminum core in a urethane shell. The device contains a range of instrumentation, including an acoustic data acquisition system that listens for leaks as the ball travels through the pipeline.

A SmartBall is a free-swimming tool capable of detecting leaks as small as 0.028 GPM in oil product pipelines and has been proven to record leaks in natural gas pipelines.[115] The tool swims through the pipeline being assessed and produces results at reduced cost to the end user compared to current leak detection methods. GPS synchronized, GIS-based above ground loggers capture low frequency acoustic signatures and digitally log the passage of the tool through a pipeline.

[115] Ariaratnam and Chandrasekaran, 2010. Development of a Free-Swimming Acoustic Tool for Liquid Pipeline Leak Detection Including Evaluation for Natural Gas Pipeline Applications. US Department of Transport HMSA. Report DTPH56-07-BAA-000002.

Scenario Results

Figure A.4: Total In Situ SAGD GHG Emissions of Different Technology Configuration Scenarios



Source: CERI

CANADIAN ENERGY RESEARCH INSTITUTE

Relevant • Independent • Objective

Oil sands innovations questionnaire

1. **Name of an innovation that is deployable in the next 5-7 years**

   Company:

2. **Please briefly explain what these technologies do?**

   What is the technology?

   What does this technology do?

   What stage is the technology?

   Concepts Application Bench Scale Prototype Demo Field Launch Commercial

   Where can it be categorized?

   A) Waste/ water Treatment (WWT)

   B) Steam generation (SG)

   C) Wells/well pads (WWP)

D) Reservoir/extraction (RES)

E) Upgrading (UPG)

F) Pipeline/transport (PT)

G) Data & Business management (BM)

H) Others: Please explain:

3. Performance parameters

i. Energy intensity (EI) - reduction on the basis of a conventional technology.

What conventional technology is used as a basis?

ii. GHG intensity – reduction on the basis of a conventional technology.

What conventional technology is used as a basis?

iii. Cost

CAPEX $/bbl/day $/Capacity
Other

OPEX $/bbl/day $/Capacity
Other

iv. Water footprint – reduction on the basis of a conventional technology.

What conventional technology is used as a basis?

v. Land footprint – reduction on the basis of a conventional technology.

What conventional technology is used as a basis?

vi. Indirect impacts

Positive

Negative