JACOBS Consultancy

Evaluation of Solid Oxide Fuel Cells for Combined Heat and Power at a SAGD Facility

August 2014

Jacobs Consultancy
Dave Butler and Associates

Section A.

Executive Summary

Background

Alberta Innovates – Energy and Environment Solutions ("AI-EES") and an industry consortium of six companies commissioned Jacobs Consultancy Canada Inc. ("Jacobs Consultancy") and our partner, David Butler and Associates Ltd. ("Butler"), to perform a high-level commercial-scale technical and economic evaluation of solid oxide fuel cells ("SOFC") for combined heat and power in a Steam Assisted Gravity Drainage ("SAGD") production application. Under AI-EES leadership, a Steering Committee was developed among the following parties to fund and direct the Study:

- AI-EES (Sponsor and Steering Committee Chair)
- BP Canada
- Cenovus Energy
- MEG Energy
- Shell Canada
- Suncor Energy (Suncor)

Dr. Viola Birss, from the University of Calgary, also participated in the Study as a technology advisor to the Steering Committee.

This report documents our methodology, basis, findings and recommendations for the application of SOFC for the generation of combined heat and power in a SAGD production application.

Problem Statement

Inherent in any SAGD complex is the need to produce heat to generate steam for the production of bitumen. The amount of steam required can vary between two barrels of cold water equivalent for every barrel of oil to four or more, depending on the reservoir. Two primary methods of generating the heat are used today:

- The first is straightforward steam generation using a boiler (usually once-through steam generator) with natural gas and produced gas as the fuel.
- The other method is generically referred to as *combined heat and power* ("CHP") and typically involves the use of a gas turbine to generate power and the use of waste heat from the turbine plus supplemental duct firing to generate steam. Power generation is

usually more than required by the SAGD plant, so the excess is sold as an export to the "grid" or another power consumer.

One of the key environmental issues plaguing both types of steam production is the generation of CO_2. Commercially available technologies to capture CO_2 are expensive, have high operating costs, and incur parasitic losses that generate additional CO_2. The result is that the avoided cost of capture can be more than \$150/tonne of CO_2.

Therefore, there is interest in developing new technologies that reduce the cost of capture or generate steam more efficiently. For this Study, it is hoped that SOFC provides a better and more efficient means of CHP, while making the CO_2 generated more amenable to capture.

Study Highlights

The following list summarizes the highlights of the Study:

- Fuel cells are commercial or near commercial and are in the "Early Adopter" phase of product development
- There are a limited number of vendors for fuel cells
- Most fuel cell development has been focused on the production of power

  Solid oxide fuel cells focused on power generation are poor fits for low-power, high-heat-demand operations such as SAGD

Study Basis

The evaluation of SOFC in this Study required significant thought in the creation of the comparison cases to provide an objective and transparent means of evaluation. Some of the questions discussed in the kick-off meeting included:

1. What is the appropriate capacity of the SAGD facility?
2. Should the evaluation include both the surface and subsurface facilities?
3. How should the co-production of heat and power contribute to the economics of either steam or power production?
4. What sets the size of the conventional cogeneration options?
5. What sets the size and capacity of SOFC?
6. What is the impact of electrical power exports regarding value and CO_2 credits?

7. Should the cases include indirect CO_2 from the generation of power, chemicals consumed and wastes generated?

After much discussion the cases were established as summarized in Table A-1:

Table A-1.
Cases

Category	Case	Description	Electricity	Steam Generation	Steam Gen (BPD. CWE)	CO_2 Capture	Amount of CO_2 Capture	CO_2 credits/ debits for Power Export / Import (MT/MWh)
CHP Cases	**2a**	Cogen	Cogen	Cogen	99,000	---	None	Sensitivity up to .88
	2b	SOFC	SOFC	SOFC	99,000	---	None	Sensitivity up to .88
CHP + CO_2 Capture Cases	**2c**	Cogen + PCC	Cogen	Cogen	99,000	PCC	90% of direct (incl. capture)	Sensitivity up to .88
	2d	SOFC + CC	SOFC	SOFC	99,000	by FCE	90%+ of direct (incl. capture)	Sensitivity up to .88

Regarding the questions above, we agreed on the following basis:

1. The Central Processing Facility (“CPF”) is designed to produce 99,000 BPCD of steam.
2. Only the CPF is considered except for power requirements related to mechanical lift at the wells.
3. The CPF is sized to produce 99,000 BPCD of steam via main steam generation technology. Excess power is exported with a credit for sales to the grid.
4. Cogeneration is sized to produce 100% of the steam using duct firing of the Heat Recovery Steam Generators (HRSGs). For this study, two Frame 7 gas turbines and HRSGs were required.
5. The SOFC in Cases 2b and 2d is sized to produce all the steam necessary for the facility; excess power is exported with a credit for sales to the grid.
6. The value of export power is the same as imported power adjusted for transmission charges. The economics of the cases were analyzed under various power prices. The CO_2 credits associated with power exports are based on sensitivities up to 0.88 Mt/MWh.
7. Electrical consumption at the site contributes to indirect CO_2 emission and will be included with direct CO_2 emissions for this study.

Methodology

At a high level, Jacobs Consultancy and Butler performed the following main activities:

1. Estimated the technical information and all the balances for each of the cases as follows:
    a. Based on in-house information, developed the technical data and balances for the conventional SAGD CPFs for Cases 2a and 2c.
    b. Using publicly available information, developed the technical data and balances for the conventional amine-based post-combustion capture for Cases 2c and 2d.
    c. Entered into a non-disclosure agreement with Fuel Cell Energy, Inc. (“FCE”) to obtain information for SOFC in Option 2b, and SOFC and carbon capture in Option 2d.
    d. Transmitted design parameters for the SOFC to FCE.
    e. Sense-checked the data and balances from FCE and documented in the technical summary.
2. Designed a technical summary sheet to compare each of the cases and provided the necessary inputs for the economic calculation.
3. Set up Butler’s proprietary economic model to calculate the metrics established by the Steering Committee.
4. Calculated the technical and economic metrics.
5. Assessed the SOFC technology for technical readiness.
6. Documented findings and provided recommendations for the Steering Committee.

New Technology Readiness Assessment

Our technology readiness assessment is based on a 9-step Technology Readiness Level (“TRL”) category system developed by NASA and modified for process plant applications where a TRL 1 is a concept and TRL 10 is commercial. Table A-2 below gives the TRL levels for the SOFC technology as considered, respectively, by Cases 2b and 2d.

Table A-2.
Technology Readiness

Technology	TRL	Description
SOFC	7	System in operation at or near full commercial scale. Most functions available for demonstration and test.
SOFC with carbon capture (oxyburn portion only)	7	System prototyping underway. Components in commercial operation.

Results

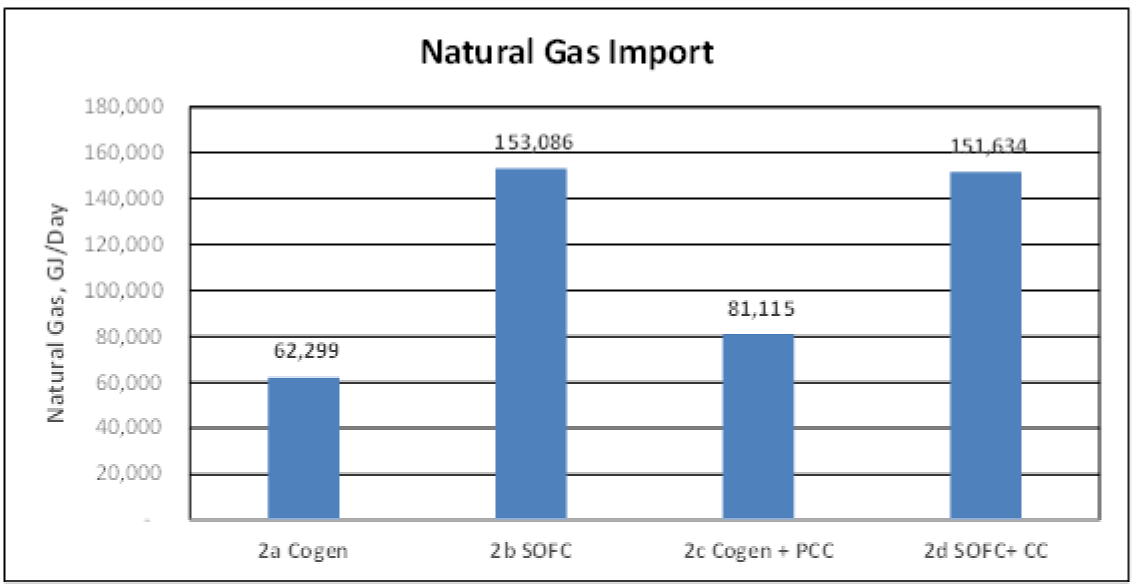
Regarding the objectives identified above, the results of our Study are as follows:

Technical Results

A few key results emerge from the technical information, as shown in Figures A-1 through A-4.

- As indicated by Figures A-1 and A-2, SAGD facilities have a large natural gas demand but are not power intensive.
- Case 2b, the SOFC case, consumes about 145% more natural gas than the Cogen case.
- CO_2 capture requires more natural gas than the cases without capture, except for Case 2d versus Case 2b.
- CO_2 capture with Case 2d requires less natural gas than Case 2b due to energy recovered from the oxygen combustion of the SOFC offgas.

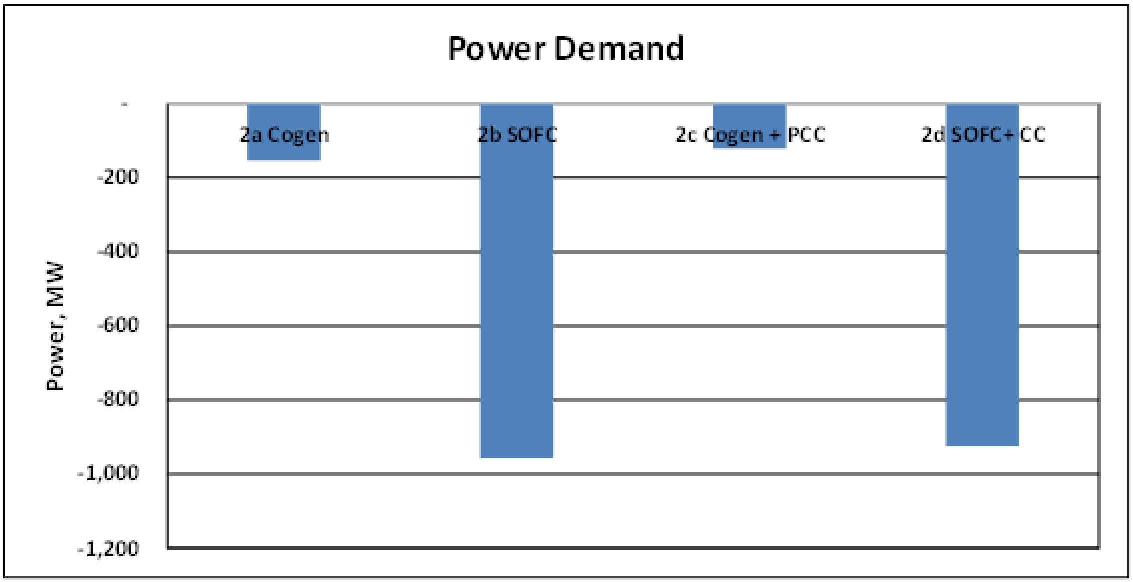
Figure A-1.
Natural Gas Import



From a power perspective, key points as shown in Figure A-2 are as follows:

- Due to relatively low internal demand for power, all cases export power.
- The Cogen cases have power exports in the range of 100 to 175 MW.
- The SOFC cases have power exports in excess of 900 MW.

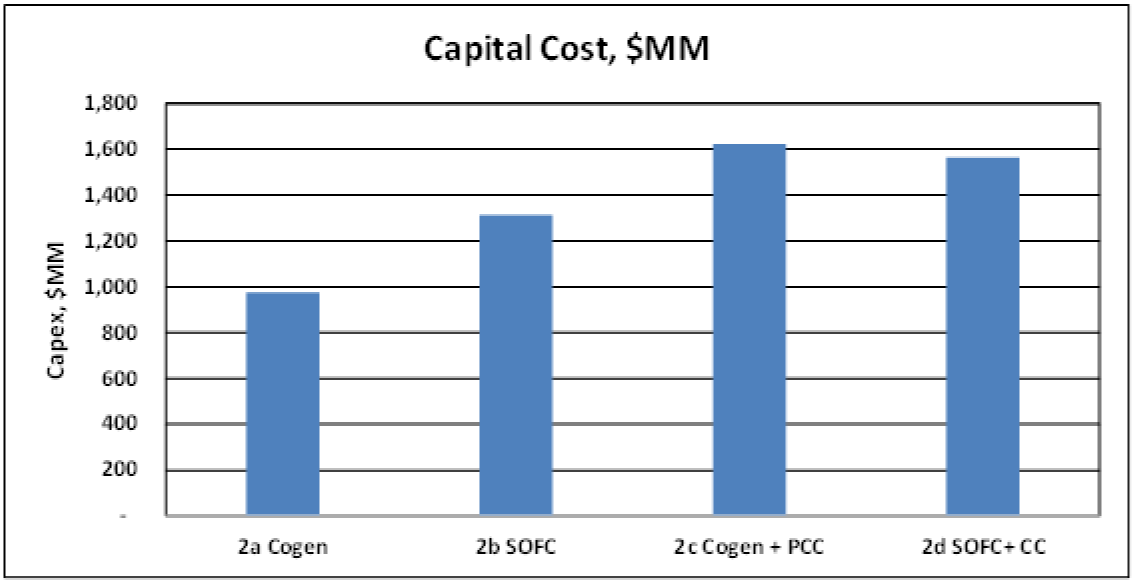
Figure A-2.
Net Power



As shown in Figure A-3, key points from a capital cost perspective are as follows:

- Not surprisingly, carbon capture universally increases the capital cost of the facilities.
- Cogen with post-combustion capture is more expensive than the SOFC technology cases.
- Conventional post-combustion capture is costly, adding nearly 50% to the capital costs for Cogen.

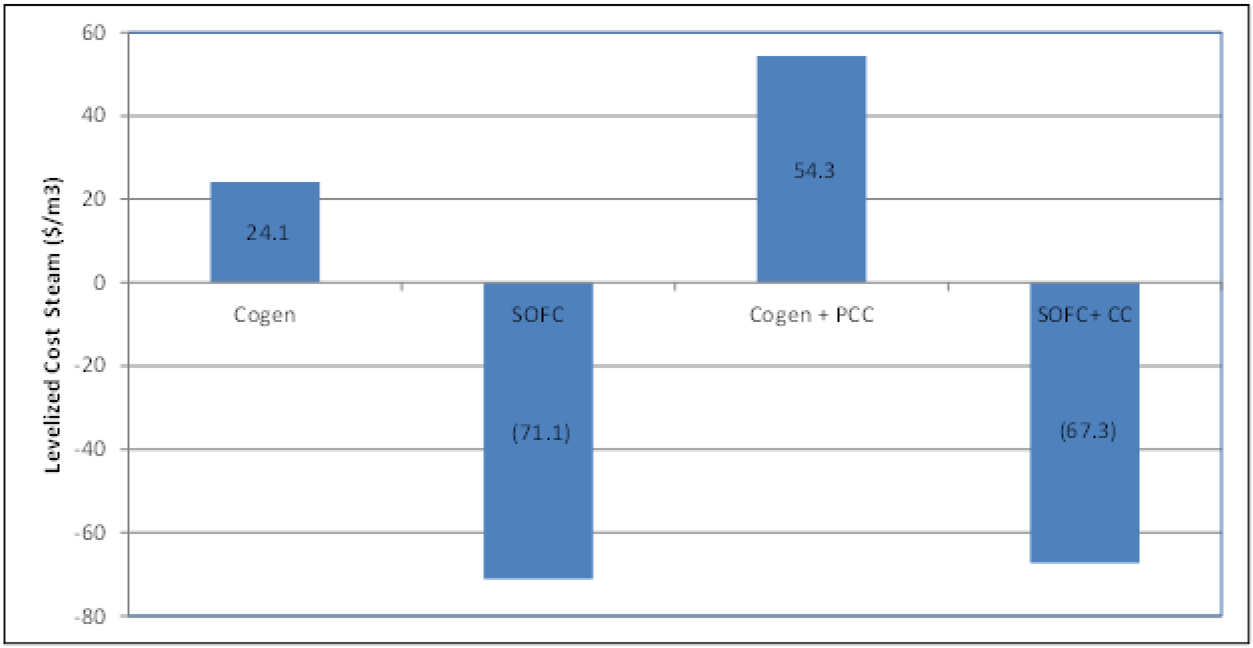
Figure A-3.
Estimated Capital Costs



Economic Results

The levelized cost of steam is the primary economic metric for comparing the various technologies. Figure A-4 below shows the net levelized cost of steam produced for the various cases. Cogen without CCS offers the lowest levelized cost of steam. The SOFC case without CCS has the lowest levelized cost of steam. Adding carbon capture to the SOFC case slightly increases its levelized cost of steam. Both SOFC cases provide negative costs for steam production because of the carbon credits (at 0.88 tonne/MWh) applied to the high amount of power production in those cases.

Figure A-4.
Net Levelized Cost of Steam



Another important economic metric is the cost of capture. Figure A-5 shows the cost to capture for the two CO_2 capture cases considered. These values were derived by assessing the cost of CO_2 capture on the same base option without CCS. The SOFC CCS case has the lowest cost of capture. The SOFC CCS case has a low capture cost because it does not cost much to purify the CO_2 produced by the fuel cell.

Figure A-5.
Net CO_2 Capture Costs

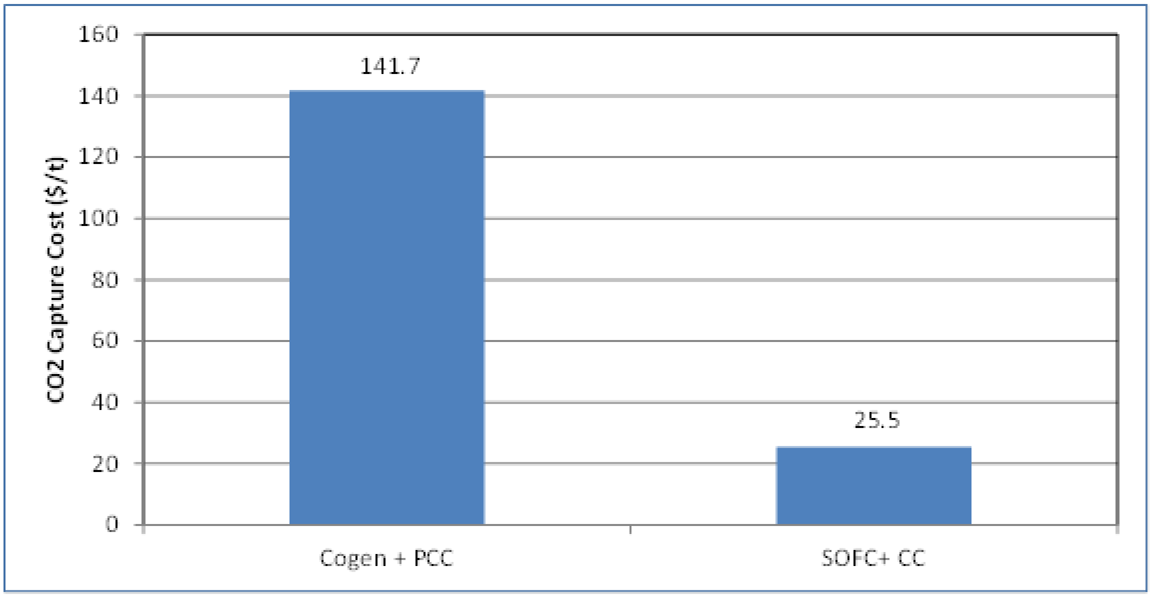
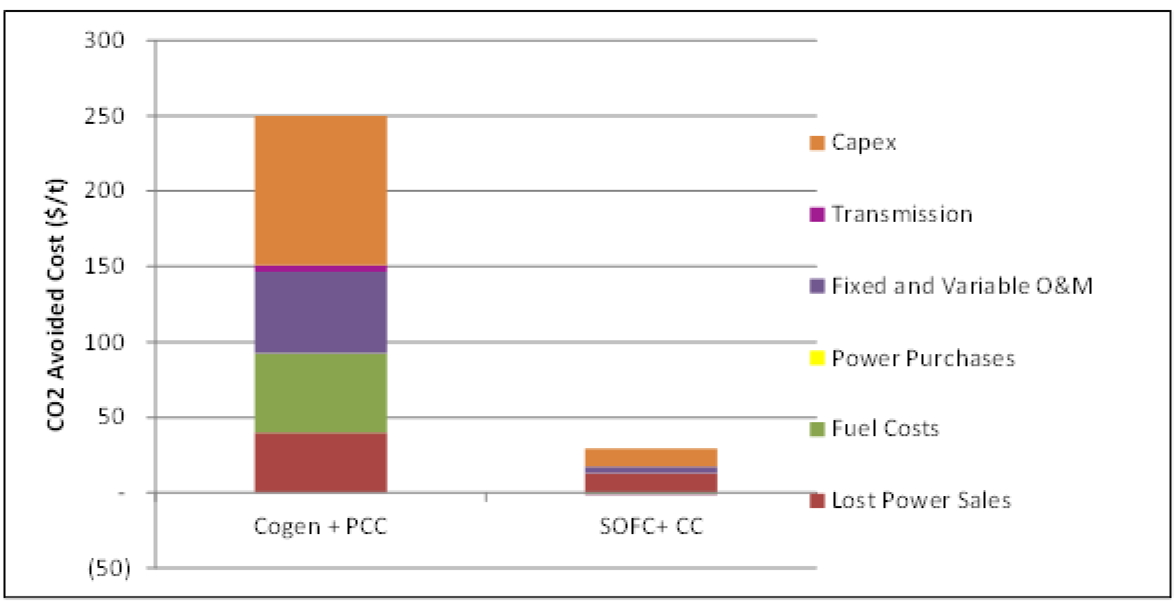


Figure A-6 shows the avoided cost of CO_2 for the two CO_2 capture options. Both options are compared against their own base technology without CCS. The SOFC CCS case incurs little cost to purify the CO_2 produced by the fuel cell.

Figure A-6.
Avoided CO_2 Costs



Findings and Recommendations

The following are Jacobs Consultancy's findings regarding the use of fuel cell technologies for SAGD:

- The Solid Oxide Fuel cell is a power producer with heat as a by-product and is not well matched to thermal in-situ which has a large heat load and small power load. A typical thermal in-situ plant has a demand of about 10 MW of heat for every MW (thermal equivalent) of power. An SOFC, on the other hand, produces about one MW of high-temperature heat for every 7 MW (thermal equivalent) of power. This results in a mismatch of 70 to one as compared to the requirements for bitumen production. Any efforts to reduce the power to heat ratio on an SOFC result in bypassing fuel around the anode side and combusting it with air—which, in effect, becomes like having an OTSG to produce steam with a small SOFC to produce the power for the site. Additionally, there may be other issues such as land use and capital cost uncertainty that may negatively impact SOFC as a CHP technology for SAGD.
- However, combined heat and power ("CHP") can be attractive for a thermal in-situ site and provides a better match between heat and power. For example:
  - Conventional cogen produces steam with a cost about 40% lower than WLS+OTSG and with a manageable amount of power sold to grid.
- CO_2 capture and compression increase the cost of producing steam.
- However, fuel cells are relatively cost effective for CO_2 recovery assuming power produced can be sold to grid
  - On paper, due to **very high power sales**, SOFC has capture and compression costs that are roughly one-fourth of conventional CHP with PCC (but again, there is a mismatch of heat and power for SAGD).

Our recommendations are summarized as follows:

- Focus efforts on SOFC as a power producer, not as a CHP technology for thermal in-situ plants.
- Therefore, we recommend in the near term:
  - Feasibility studies on a commercial-scale plant to confirm capital costs and commercial viability for:
    - Cogen and OTSG-based thermal in-situ, SMR and Fired Heaters.

Section B.

Background, Scope, and Assumptions

Background

Alberta Innovates – Energy and Environment Solutions ("AI-EES") and an industry consortium of six companies commissioned Jacobs Consultancy Canada Inc. ("Jacobs Consultancy") and our partner, David Butler and Associates Ltd. ("Butler"), to perform a high-level commercial-scale technical and economic evaluation of solid oxide fuel cells ("SOFC") for combined heat and power in a Steam Assisted Gravity Drainage ("SAGD") production application. Under AI-EES leadership, a Steering Committee was developed among the following parties to fund and direct the Study:

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One of the key environmental issues plaguing both types of steam production is the generation of CO_2. Commercially available technologies to capture CO_2 are expensive, have high operating costs, and incur parasitic losses that generate additional CO_2. The result is that the avoided cost of capture can be more than $150/tonne of CO_2.

Therefore, there is interest in developing new technologies that reduce the cost of capture or generate steam more efficiently. For this Study, it is hoped that SOFC provides a better and more efficient means of CHP, while making the CO_2 generated more amenable to capture.

SOFCs have been considered as a potentially advantageous technology for generating CHP. Alberta has been one of the global leaders in SOFC development. The application of SOFC in thermal in-situ processes has also been contemplated by some SOFC researchers and developers.

Scope of Study

The objectives of the Study were as follows:

- Evaluate SOFC technology for CHP associated with thermal in-situ recovery.
- Prepare a technology readiness assessment of SOFC using Fuel Cell Energy's (FCE) SOFC technology as an example.
- Compare SOFC to commercial CHP processes from both a technical and economic perspective.

The deliverables of the Study are as follows:

- Facilitate a kick-off meeting to finalize the cases for evaluation.
- Estimate and provide technical data needed for evaluation of all cases, either through in-house data, publicly available information, and/or licensor involvement.
- Prepare a technology readiness assessment of SOFC.
- Facilitate an interim review meeting to discuss preliminary results and refine plans for the rest of the Study.
- Prepare and deliver a final presentation and report.
- Facilitate a site visit for Steering Committee members to visit an operating fuel cell site.

SAGD Facility

For the purposes of the Study, each case was designed in concept to support SAGD production consistent with the following parameters:

- All SAGD units are sized for 33,000 BPCD of oil production.
- The SAGD steam-to-oil ratio ("SOR") is assumed to be 3 (based on barrels of water consumed per barrel of oil produced). This means that in all cases the CPF will produce 99,000 BPCD of dry steam (CWE basis).
- Steam is to be supplied at 100 bar and assumed to be 77% quality steam from the generator but before the high-pressure separator.
- Electric submersible pumps are assumed for lifting the bitumen from the reservoir.
- Imported electricity is supplied from the Alberta grid.
- Natural gas is supplied by pipeline.
- CO_2 produced will meet Kinder Morgan pipeline specifications at battery limits.
- The life of the plant is 30 years.
- At least 90% CO_2 capture is required for carbon capture cases.

CO_2 Calculation Assumptions

Both direct and indirect GHG emissions were considered:

- Direct GHG emission consisted of the CO_2 produced from the burning of produced gas and natural gas for steam generation.
- Indirect GHG emissions resulting from:
    - Imported power generation
    - Trucking of wastes
    - CO_2 generated in the production of imported chemicals

Comparative and Economic Assumptions

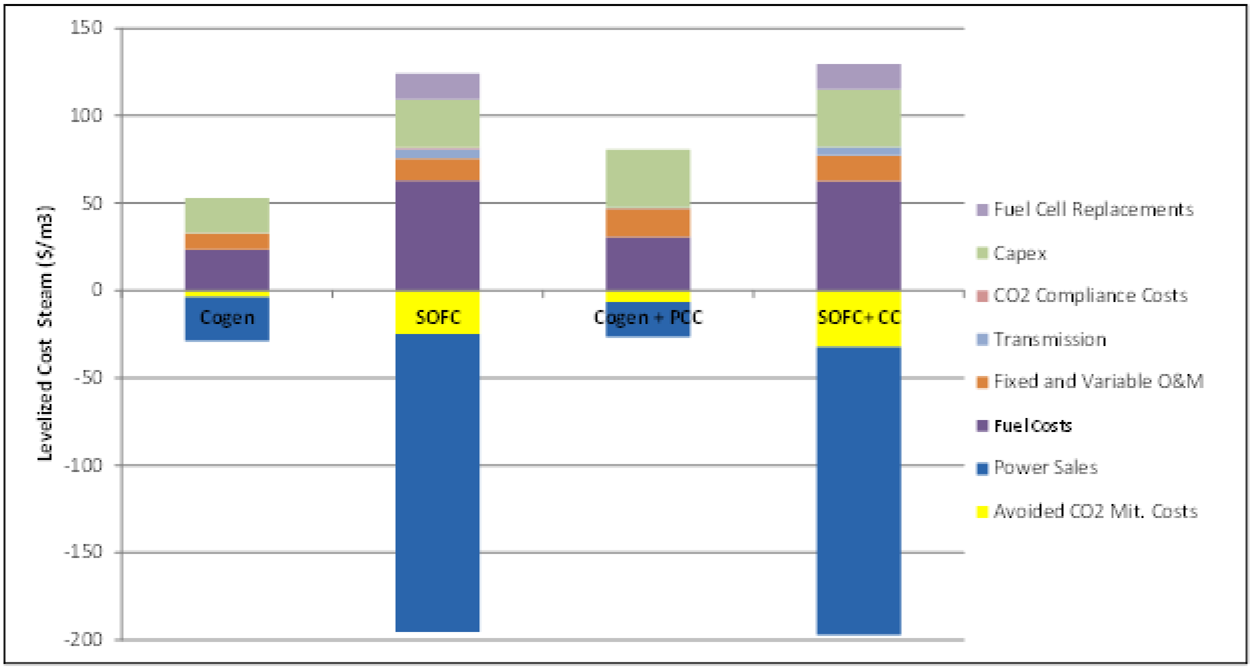
The following are the key comparative and economic assumptions for the Study as agreed to by the Steering Committee.

As the comparison of the cases was a ranking assessment as opposed to a full cost assessment, the following simplifications were made:

1. Taxes (including property taxes) or royalties are not included.
2. Un-levered analysis using a cost of capital of 10 percent.
3. The Steering Committee has agreed to use the flat levelized approach. All the underlying costs and other revenues have been escalated by 2% in a given year. The same price for steam for all years is derived by setting the NPV of a given case to zero with a discount rate of 10 percent.
4. The cost of capture will only include the capital and operating cost necessary to get the CO_2 to the plant gate at Kinder Morgan specifications.
5. Power transmission charges are 3% of net sales to AESO grid and 15% for purchases from grid.
6. Abandonment or reclamation charges are zero.

The technologies are ranked by the Levelized Cost of Steam.

Figure B-1.
Example of Levelized Cost of Steam Approach



The following commodity prices and other operating costs were used for the Study:

1. Power Price Forecast: $90/MWh escalating 2% per year
2. Gas Price Forecast: $5.00/GJ escalating 2% per year
3. Inflation and Escalation: 2% per year
4. Water has no charge once permitted for use
5. Water treating chemicals cost roughly $0.77/m^3 of water treated
6. MEA costs (for PCC): $2.40/kg
7. Corrosion inhibitor (for PCC): $7.20/kg
8. Mole sieve: $4.80/kg
9. WLS sludge disposal: $150/tonne
10. MEA solid waste disposal: $1,400/tonne
11. Other fixed and variable operating costs are 3.5% of capital cost

The primary focus of the Study was to understand how SOFCs perform relative to commercially available processes on the cost of carbon capture. Therefore, the following conventions and sensitivities were included in the analysis:

1. **CO_2 Credits—**If a case has no carbon capture then it will be required to mitigate 12% of its CO_2 emissions at $15/t. The cases with carbon capture should be able to sell the volume of CO_2 captured less 12% of the plant CO_2 production as a CO_2 credit. (It can also be used internally to avoid having to purchase credits elsewhere.)

2. **Avoided CO_2 Costs—**The base technology without CCS will be the reference case for each of the carbon capture cases. The GHG emissions associated with this additional energy required to capture CO_2 are netted out of the mass of CO_2 captured to determine the mass of CO_2 avoided. Therefore:

   CO_2 Avoided = CO_2 Captured – CO_2 for power from the grid used to capture CO_2 + CO_2 credits for power produced - CO_2 for incremental fuel.

   The avoided cost is determined by taking the incremental cost to produce steam in a given year, as derived above and dividing it by the mass of CO_2 avoided. Some entities are more familiar with the avoided mass of CO_2 expressed as:

   CO_2 Avoided = CO_2 emitted in reference case without CCS – CO_2 emissions with CCS – CO_2 from power used from grid + CO_2 credits for power produced.

   CO_2 emissions with CCS would include CO_2 emissions produced to provide steam used to capture CO_2.

To understand the sensitivity of the case rankings and economics to various factors, the following sensitivities were included in the economic results:

1. Natural gas prices: $2 to $9/GJ, escalating each year by inflation
2. Technology life of fuel cells: 3 to 10 years
3. Capital cost: -15, 0, +50, +100 of base capital cost of the CO_2 capture technology
4. Power price effect, power prices at $50 to $110/MWh escalating by inflation
5. CO_2 credit value/compliance cost: $0/te, $15/te, $30/te, $40/te, and $80/te
6. Show impact of GHG intensity for power ranging from 0 to 0.88 t/MWh
7. Increase in the capital cost of SOFC cases by up to 5 times
8. 100% increase in the capital cost for carbon capture

Capital Cost Estimate Basis

Cost Curve and Unit Rate Basis

The curve costs used in some of the cases were developed from Jacobs Engineering Group's ("Jacobs") in-house cost estimating work and take into account:

- Historical construction indirect factors
- Historical home office factors
- All-in unit rates (infrastructure, gathering lines and pipelines)
    - All-in unit rates include:
        - Direct labour and material costs
        - Contractor's construction indirect costs
        - Construction management

Jacobs' Unit Cost Curves ("UCCs") were used in the preparation of the process unit costs. The UCCs are based on the following key information from past and current SAGD projects:

- Sized equipment lists
- Engineering Design Study quality (30% engineering complete) material take-offs
- Firm equipment quotes
- Current market pricing for all major commodities (second quarter 2011)
- Bulk material unit installation man-hours (actual)
- Labour costs (adjusted for specific project requirements)
    - $65.00 per direct field labour hour
    - $130.00 per module hour

Jacobs' cost estimates are based on a variety of sources as follows:

- For Case 2a, we used UCCs for SAGD CPFs using Cogen for steam generation. The cost curves are intended to be Total Installed Costs ("TIC") for various operating blocks of the plant and are based largely on capacity. We have TIC cost curves with capacity drivers for the following:
    - Oil Treating—emulsion flow rate

- De-oiling—produced water rate
- Water Treating—Boiler Feed Water rate and Lime Softening feed
- Steam Generation—Dry steam rate
- Hydrocarbon Tankage—hydrocarbon hold-up volume
- Excavation—approximate CPF land area
- Utilities and Offsites—factored from dil-bit rate

Other costs, home office, and engineering for the CPF are typically factored from the sum of the TIC of the operating blocks.

- For Case 2c, we prepared our estimate from the cost curve method for Case 2a and then added data for post-combustion capture using publicly available data on Fluor's Econamine process. For convenience, we adjusted all costs for PCC to a USGC basis and then used a location factor of 1.5. The publicly available sources for PCC performance and costs include:
  - David and Herzog—2012 (the cost of carbon capture)
  - Chapel and Mariz—NETL 1999
  - Global CCS Institute (Economic Assessment of Carbon Capture and Storage)—2011 update
  - DOE/NETL—401/110907
  - DOE/NETL—401/110509
  - DOE/NETL—402/102309
  - Simmonds, Hurst, Wilkinson, Reddy, Khambaty—May 2003
  - ROAD | Maasvlakte CCS Project C.V.—November 2011
  - US EIA—November 2011—Updated Capital Cost Estimates for Electricity Generation Plants
- For Cases 2b and 2d, the estimate was prepared based on FCE's future expected equipment costs (assuming substantial increases in the number of fuel cells sold) and our installation costs.

Alberta Labour Market

The estimate is based on the Alberta labour market using the key assumptions shown in Table B-1:

Table B-1.
Labour Assumptions

Description	All Cases
Pricing Basis	1Q 2013
Workforce	CLAC
Construction Schedule (Construction to Mechanical Completion)	22 months
Work Schedule	10/4
All-in Field Rate Build-Up:	
(1) Direct Labour Wage Rate	65.00$
(2) Contractor Indirects (Incl. Fee)	92.10$
(3) Camp (Per Direct Hour)	33.44$
(4) CM	22.50$
All-in Rate (1+2+3+4):	***213.04$***
Scaffolding (% OF AG Hours)	26%
Productivity	1.35
Modularization %	40%
Modularization All In Rate	130.00$

Inclusions / Exclusions

The costs for each case include the major processing blocks mentioned above as well as the following cost components:

- Mechanical equipment
- Electrical equipment
- Bulk materials
- Direct field labour costs
- Contractor construction indirects (including contractor fee, overhead, and minor craft attraction incentives)
- Construction management costs
- Material-related costs (freight, module transportation, vendor assistance)

- Home office engineering (FEED, detail design, home office construction support and third party engineering)
- Contingency

The following key items are **excluded** from the estimate:

- Owner's costs
- Pre-FEED costs
- Incurred costs
- Field facilities (well pads, gathering lines)
- LACT (lease automatic custody transfer)
- Main Substation
- HV incoming power cables and associated HV tie-ins
- Access roads
- Off-sites (pipelines, salt cavern)
- Disposal facilities/pond
- Commissioning and start-up costs
- Drilling and completions
- Any process unit not explicitly listed (Cogen, DRU)
- Demolition and disposal
- Escalation
- Foreign labour
- Construction workforce fly/in and fly/out

Contingency (Engineering, Procurement, Construction Risk)

For most of the cases contingency was fixed at 20%. However, we did perform some sensitivity analysis of the economics at other capex points for the new technology options. Contingency for this type of estimate accounts for the following:

- Minor process unit capacity changes
- Minor construction work-hours (productivity) and labour pricing fluctuations
- Engineering work-hours and services pricing fluctuations

- Minor schedule delays
- Minor estimating errors and omissions
- Minor impacts to costs due to client-specific design requirements not accounted for in the Jacobs cost curves and historical unit rates
- Minor impacts to costs due to project-/client-specific execution requirements not accounted for in the Jacobs cost curves and historical unit rates
- Minor pricing fluctuations due to supply and demand (outside of typical escalation)
- Minor risks associated with site soil conditions (e.g., site grading, muskeg quantities)

Not Covered by Contingency

- Technical cost risk associated with new and emerging technologies
- Project location changes
- Major process unit capacity changes
- Product specifications
- Major material price fluctuations (extreme change in market conditions)
- Major schedule delays
- Scope changes / additional scope including:
  - Plant capacity changes
  - SOR changes
  - Technology changes
  - Increases in number of pipelines or pipeline lengths, sizes and thickness
  - Increases in gathering line lengths, sizes and thickness
  - Additional gathering lines (only emulsion / steam lines have been included in estimate)
  - Changes in number of well pairs
  - Costs associated with ROW sharing or crossing of other Owner organizations
- Major estimating errors and omissions
- Major impacts to costs due to client-specific design requirements not accounted for in the Jacobs cost curves and historical unit rates
- Major impacts to costs due to project-/client-specific execution requirements not accounted for in the Jacobs cost curves and historical unit rates
- Major risks associated with site soil conditions (e.g., site grading, muskeg quantities)

Section C.

Case Descriptions

Case Development

A group of cases were agreed to at the kickoff meeting to compare the FCE SOFC technology in a CHP CPF. A total of four cases were developed:

- **Combined Heat and Power ("CHP") Cases (sized to produce 100% of the steam required)**
  - Case 2a—WLS + gas turbine ("GT") + heat recovery steam generator ("HRSG") without CC
  - Case 2b—WLS + SOFC without CC
  - Case 2c—WLS + GT + HRSG with PCC to capture at least 90% of direct CO_2
  - Case 2d—WLS + SOFC with CC to capture at least 90% of direct CO_2

The cases are summarized in Table C-1 below:

Table C-1. Cases

Category	Case	Description	Electricity	Steam Generation	Steam Gen (BPD. CWE)	CO_2 Capture	Amount of CO_2 Capture	CO_2 credits / debits for Power Export / Import (MT/MWh)
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	2b	SOFC	SOFC	SOFC	99,000	---	None	Sensitivity up to .88
CHP + CO_2 Capture Cases	2c	Cogen + PCC	Cogen	Cogen	99,000	PCC	90% of direct (incl. capture)	Sensitivity up to .88
	2d	SOFC + CC	SOFC	SOFC	99,000	by FCE	90%+ of direct (incl. capture)	Sensitivity up to .88

The following conceptual flow diagrams provide a high-level flow-scheme for each case, illustrating the flow of each major water and energy streams.

Figure C-1.
Case 2a

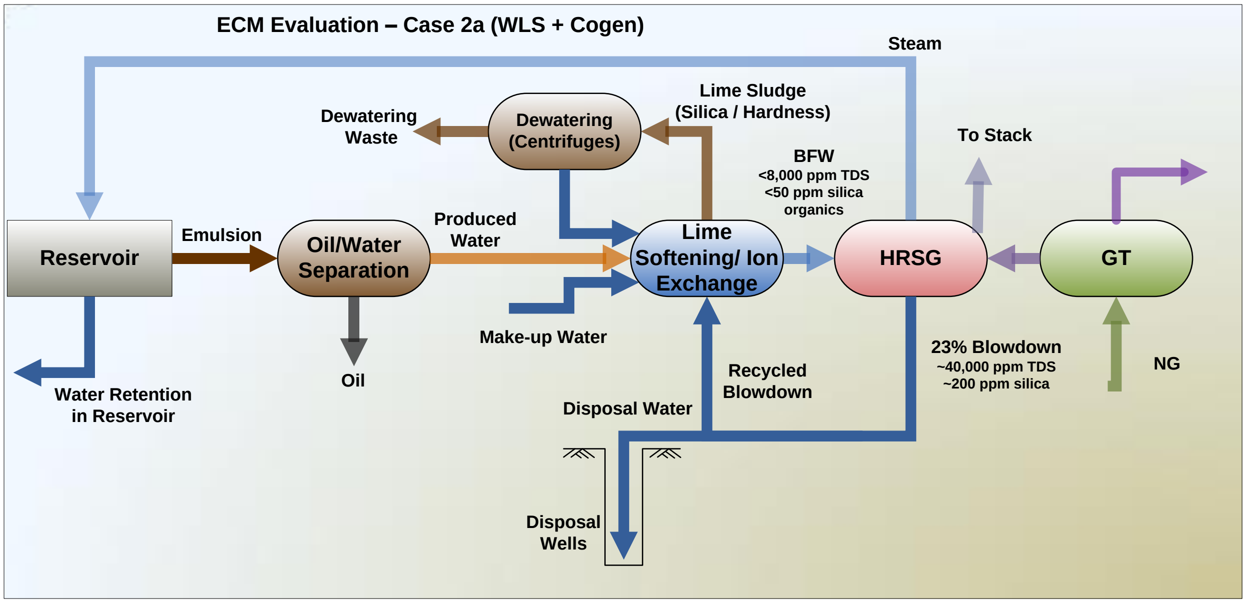


Figure C-2.
Case 2b

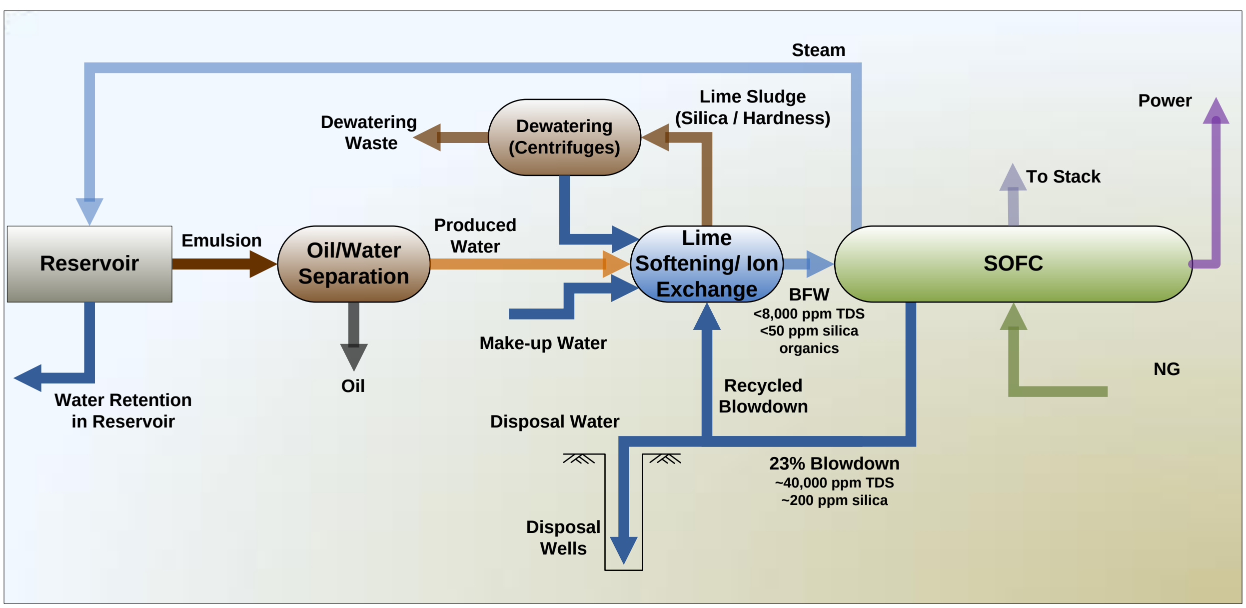


Figure C-3.
Case 2c

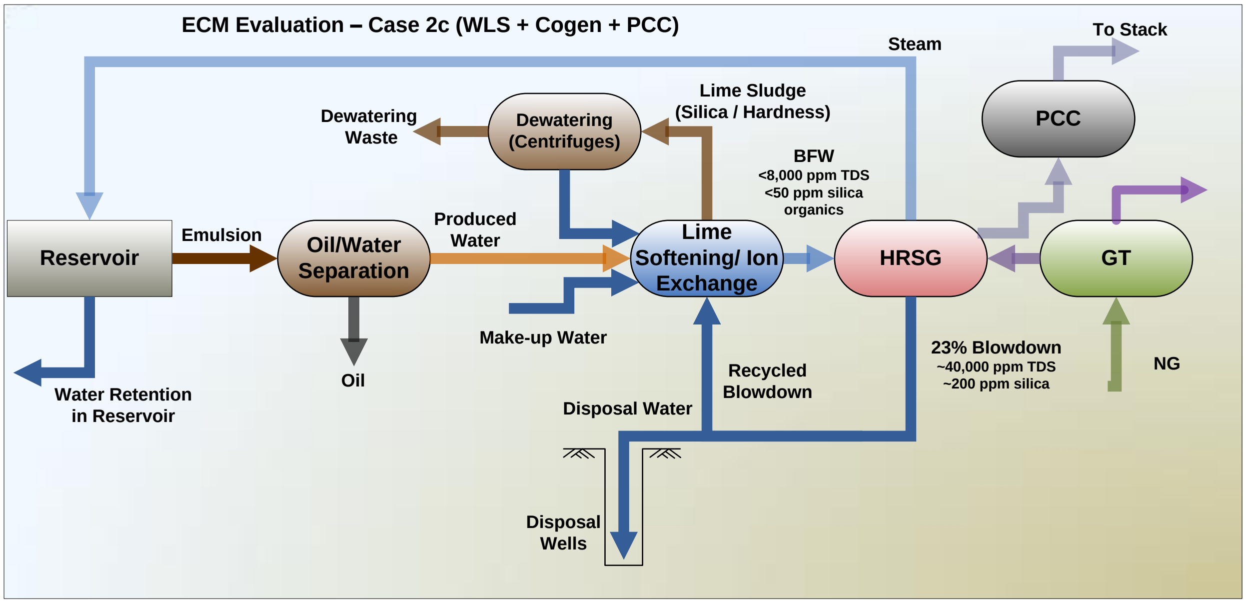
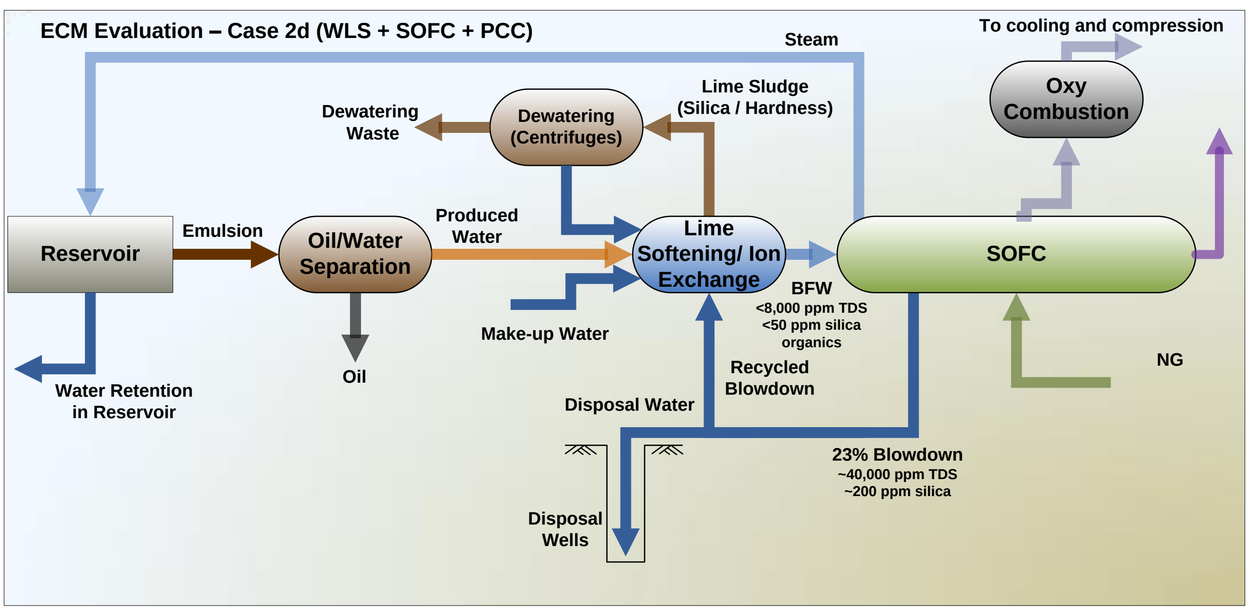


Figure C-4.
Case 2d



Section D.

Technology Description and Readiness Assessment

Solid Oxide Fuel Cell (SOFC)

Background

The SOFC design considered for SAGD operation is derived from the conventional SOFC designed for power generation with heat recovery for steam generation. The principal of the SOFC is that a carbon-containing fuel is supplied to the anode, and air is supplied to the cathode. Oxygen ions transfer electricity across the electrolyte 'combusting' the fuel and releasing CO_2 and water into the anode offgas steam. The SOFC operates at high temperatures (500 to 1000°C), and waste heat can be recovered to generate steam for the SAGD operation.[1]

Process Description

For use in thermal in-situ bitumen production as in Cases 2b and 2d, the SOFC commercial configuration remains unchanged. The only change is that excess heat is used to generate steam for bitumen production rather than being rejected to the atmosphere. Air is preheated by heat exchange with the anode offgas combustion stream and fed to the cathode in the SOFC. Oxygen ions diffuse across the electrolyte to the anode where they 'react' with the fuel and release electrons. The electrons flow through the external circuit back to the cathode to generate more oxygen ions from the air on the cathode side.

The sensible heat is recovered from the cathode offgas which is then vented to atmosphere. The offgas from the anode contains some unconverted fuel, which is catalytically combusted with air; the heat recovered is used to preheat the incoming air and generate steam for the SAGD operations.

In carbon capture mode, the offgas from the anode is combusted catalytically with high-purity oxygen (oxy-combustion). In this case, the 'flue gas' is predominantly CO_2 and steam. Heat is recovered from this stream for preheating the incoming air and fuel and for generating steam. It is then cooled to ambient temperature to knock out the water. The stream is dried and compressed to pipeline pressure.

History and Development

The SOFC technology has been under development for power generation for 50 years. It has been deployed commercially on the hundreds of kW scale.

The commercial use of pure oxygen to promote combustion dates back over a century, and

[1] For more information visit http://www.csa.com/discoveryguides/fuecel/overview.php

there are many commercial examples of using oxygen to catalytically combust fuel gas components to generate an inert gas stream. Using oxygen and catalytic combustion has not been practiced on this scale nor has it been used to capture CO_2 from SOFC flue gases on a commercial scale.

SOFCs for power generation are being actively marketed by several vendors at sizes up to several hundred kWe.

Oxy-combustion—the practice of burning fuels in pure oxygen to capture CO_2—is under development by a number of commercial organizations, research centres and government agencies around the world. However, these development programs have not reached the scale required by a 1 GW SOFC plant. There is no active development or commercialization program underway for using pure oxygen and catalytic combustion to capture CO_2 from SOFC.

Readiness of the Technology

The SOFC and oxy-combustion represent two distinct parts of the technology and are considered separately for technical readiness.

SOFC for power generation is at a TRL of 8. Commercial plants of a few hundred kW are in operation with the Early Adopter cadre of customers. They are not yet in mainstream commercial operation as are, for example, gas turbines, steam turbines, and reciprocating engines. This is primarily due to the much higher capital cost per unit of electricity generated by SOFC than for other forms of electricity generation from fossil fuels, rather than any inherent issue with the technology.

Configuring the technology for power and steam production results in a change to the balance of plant rather than the fuel cell stack itself, and as such reduces the TRL to 7 because although electricity generation from SOFC is commercial, high-pressure steam generation with SOFC has not been done commercially.

Using pure oxygen to catalytically combust the residual fuel in the anode offgas ready for CO_2 capture is at a TRL of 7. High-purity air separation plants of this scale are in widespread operation, and most of that oxygen is used in either combustion or catalytic processes. However, using combustion with pure oxygen to capture CO_2 is only at the prototype stage and integration with SOFC has only been modelled.

Section E.

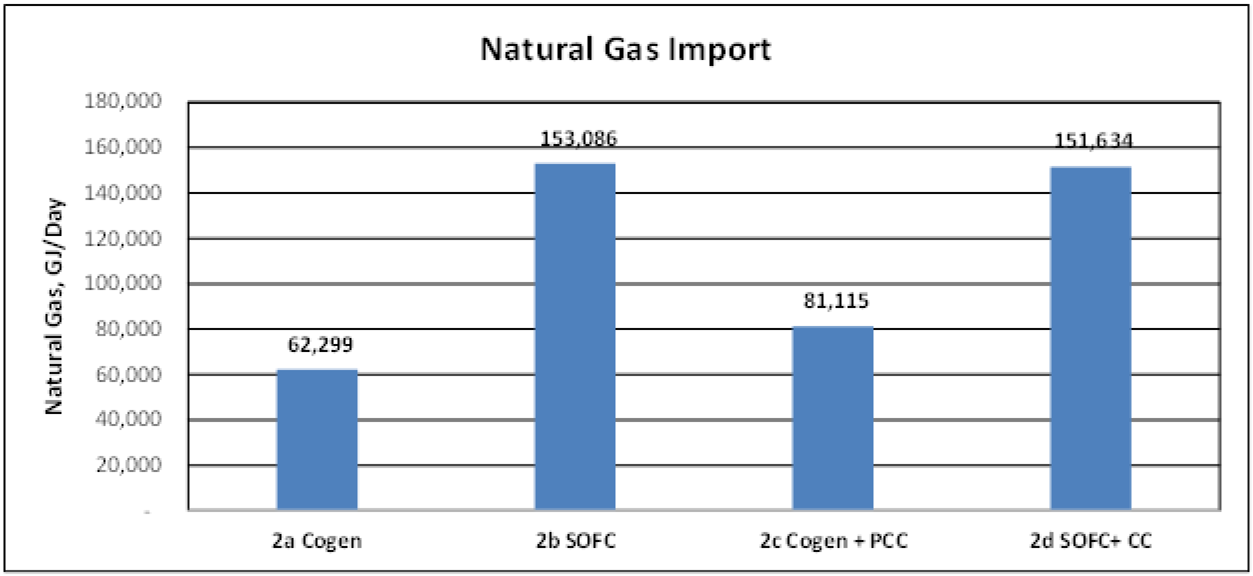
Technical Results

A summary of the technical information for the cases is included in Table E-1. As indicated in Section B of this report, our technical analyses are based on in-house information for Case 2a. The post-combustion capture costs for Case 2c are based on publicly available information for the Fluor Economine process. The technical information for Cases 2b and 2d are based on simulations and results provided by FCE.

A few interesting results emerge from the technical information, as shown in Figures E-1 through E-3:

- As indicated by Figures E-1 and E-2, SAGD facilities have a large natural gas demand but are not power intensive.
- Case 2b, the SOFC case, consumes about 145% more natural gas than the Cogen case.
- CO_2 capture requires more natural gas than the cases without capture, except for Case 2d versus Case 2b.
- CO_2 capture with Case 2d requires less natural gas than Case 2b, due to energy recovered from the oxygen combustion of the SOFC offgas.

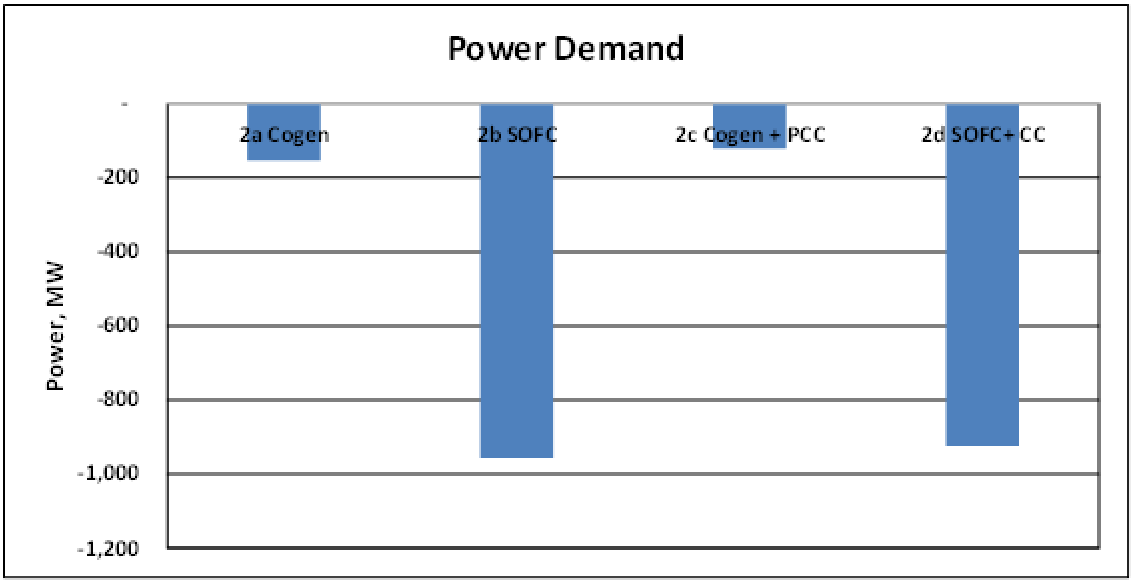
Figure E-1.
Natural Gas Import



From a power perspective:

- Due to relatively low internal demand for power, all cases export power.
- The Cogen cases have modest power exports.
- The SOFC cases have large power exports.

Figure E-2.
Net Power



From a capital cost perspective:

- Not surprisingly, carbon capture universally increases the capital cost of the facilities.
- Cogen with post-combustion capture is less expensive than the SOFC technologies.
- Conventional post-combustion capture is costly, adding nearly 50% to the capital costs for Cogen.

Figure E-3.
Estimated Capital Costs

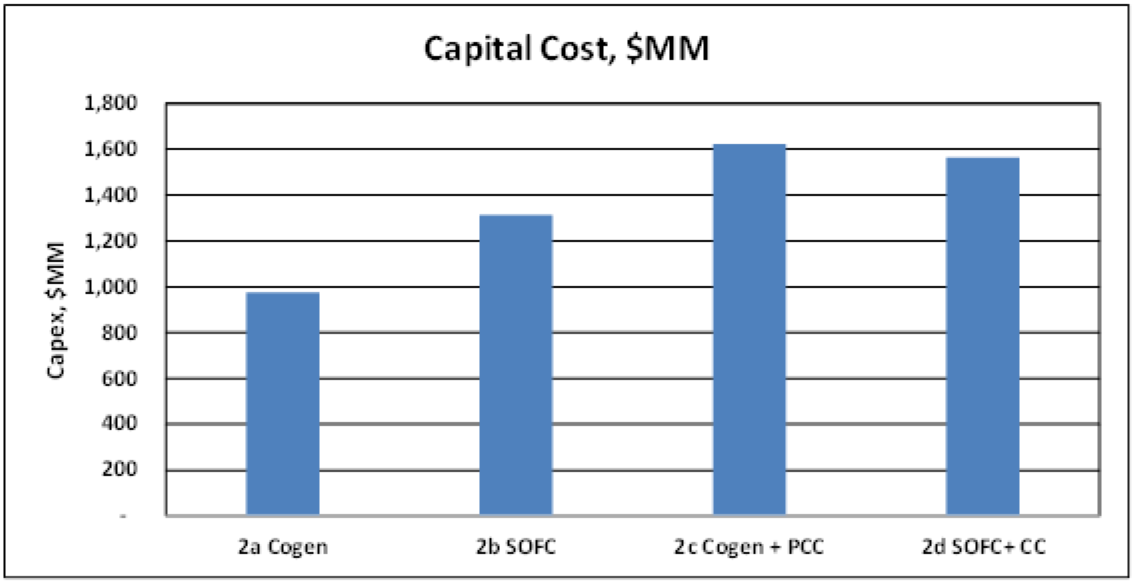


Table E-1.
Technical Data Summary

Calendar Day Rates by Case (Rev 13)		2a Cogen	2b SOFC	2c Cogen+PCC	2d SOFC+CC
Bitumen Production	**BPD**	33,000	33,000	33,000	33,000
Steam Production for SAGD	**BPD CWE**	99,000	99,000	99,000	99,000
Steam Production for Carbon Capture	**BPD CWE**			39,061	
Sulphur Production	**tonnes/day**	0.03	0.03	0.03	0.03
Disposal Water					
Steam Production for SAGD	**m^3/day CWE**	1,693	1,693	1,693	4,391
PCC Boiler System	**m^3/day CWE**	0	0	125	0
Total	**m^3/day CWE**	1,693	1,693	1,818	4,391
WLS Sludge	**tonnes/day**	20	20	20	10
WLS Sludge	**CAD/day**	3,053	3,053	3,053	1,500
Makeup Water Rate					
Steam Production for SAGD	**m^3/day**	3,375	3,375	3,375	3,375
PCC	**m^3/day**			125	0
ECM/SOFC Water Produced	**m^3/day**				-6,072
Total	**m^3/day**	3,375	0	3,499	0
Water Treating Chemicals					
Lime	**tonnes/day**	6.9	6.9	6.9	5.0
MagOx	**tonnes/day**	2.6	2.6	2.6	2.3
Soda Ash	**tonnes/day**	0.8	0.8	0.8	0.5
Total Water Treating Chemicals	**CAD/day**	15,841	15,841	15,841	11,881
Amine Carbon Capture Chemicals					
MEA	**MMCAD/yr**			2.0	0
Corrosion Inhibitor	**MMCAD/yr**			0.4	0
Mole Sieve	**MMCAD/yr**			0.09	0
Total	**MMCAD/yr**			2.4	0
Amine Sludge Disposal	**MMCAD/yr**			1.4	0
Produced Gas Consumed					
Bitumen Production (LHV)	**GJ/day**	898	898	898	898
Bitumen Production (HHV)	**GJ/day**	1,002	1,002	1,002	1,002

Calendar Day Rates by Case (Rev 13)		2a Cogen	2b SOFC	2c Cogen+PCC	2d SOFC+CC
Natural Gas Consumed					
Bitumen Production (LHV)	**GJ/day**				
Bitumen Production (HHV)	**GJ/day**				
Cogen Steam & Power Production (LHV)	**GJ/day**	56,153		56,153	
Cogen Steam & Power Production (HHV)	**GJ/day**	62,299		62,299	
Carbon Capture (LHV)	**GJ/day**			16,960	
Carbon Capture (HHV)	**GJ/day**			18,816	
ECM (LHV)	**GJ/day**				
ECM (HHV)	**GJ/day**				
SOFC (LHV)	**GJ/day**		137,090		135,782
SOFC (HHV)	**GJ/day**		152,084		150,632
Total (LHV)	**GJ/day**	56,153	137,988	73,113	136,680
Total (HHV)	**GJ/day**	62,299	153,086	81,115	151,634
Power Consumed					
Bitumen Production	**MW**	11	11	11	11
Carbon Capture	**MW**			14	15
CO_2 Compression	**MW**	0		19	39
ECM	**MW**				
SOFC			61		45
Inverter losses			43		43
Total Power Consumed	**MW**	11	115	44	153
Power Generated	**MW**	166	1072	166	1077
Power Imported	**MW**	0		0	
Power Exported	**MW**	155	957	122	924
CO_2 Direct					
Steam Production for SAGD	**tonnes/day**				
Cogen Steam & Power Production Total	**tonnes/day**	3,217		3,217	
Carbon Capture Steam Generation	**tonnes/day**			921	
ECM Operation	**tonnes/day**				
SOFC	**tonnes/day**		7,755		7,617
CO2 Direct Total	**tonnes/day**	3,217	7,755	4,138	7,617
CO_2 Indirect	**tonnes/day**				

Calendar Day Rates by Case (Rev 13)		2a Cogen	2b SOFC	2c Cogen+PCC	2d SOFC+CC
Without Power	tonnes/day	5	5	5	4
CO_2 Captured	tonnes/day	0	0	3,724	7,615
CO_2 Generated (Direct)	tonnes/day	3,217	7,755	414	2
% CO_2 Capture (Direct Only)		0%	0%	90%	100%
Total Costs					
Total Chemicals & Disposal Costs	MM CAD/yr	7	7	13	7
Fixed O&M Costs	MM CAD/yr	34	46	57	55
Capital Cost (3Q2012, Ft McMurray)	MM CAD	975	1,311	1,623	1,563
Capital Spend Profile					
Start up - 5yr		0%	0%	0%	0%
Start up - 4yr		0%	0%	0%	0%
Start up - 3yr		15%	30%	15%	30%
Start up - 2yr		55%	50%	55%	50%
Start up - 1yr		30%	20%	30%	20%
Steam Generation					
Availability Factor		94%	94%	94%	94%
Wet Steam Quality		77%	77%	77%	77%
Fuel Cell Replacement costs	MMCAD/yr		80		80
Steam Generation					
Availability Factor		94%	94%	94%	94%
Wet Steam Quality		77%	77%	77%	77%

CO_2 capture and compression costs					
Capex	MM CAD		336	648	252
Annual Capex charge (12%)	MM CAD/yr	0	120	78	110
Base Utility costs	MM CAD/yr				
Chemicals and Catalyst costs	MM CAD/yr	0	0	6	0
Fixed O&M Costs	MM CAD/yr	0	12	23	9
Total CO_2 capture and compression costs	**MM CAD/yr**	**0**	**132**	**107**	**119**

Section F.

Economic Results

Introduction

One of the key objectives of this Study was to identify technologies that may have lower GHG emission intensities while providing steam at a reasonable cost. Given that reducing GHG emissions generally requires energy and additional capital and operating cost, it is expected that technologies with lower GHG emissions will have higher costs to provide steam. Unique to the fuel cell cases evaluated, however, is that they produced significant amounts of additional power. The value of this power contributed significantly to the economics of these cases, providing some surprising results. To compare the various options several metrics were used to assess the cost of providing steam.

The following section describes the assumptions and methodologies used, the key results, and the sensitivities associated with the key variables.

Levelized Cost of Steam

Figure F-1 shows the major cost and revenue components that make up the levelized cost of steam produced. The yellow negative values are related to the benefits associated with avoiding paying $15/t to mitigate CO_2 emissions or selling CO_2 credits. The other blue negative bar is the CO_2 benefit associated with selling additional green power to the grid. The top light purple value is associated with the cost of replacing fuel cells as they degrade over time. CO_2 compliance costs are a very small component of steam costs. CO_2 compliance costs are $15/t for the Cogen cases to mitigate 12% of emissions.

Figure F-1.
Levelized Cost of Steam ($/m³)

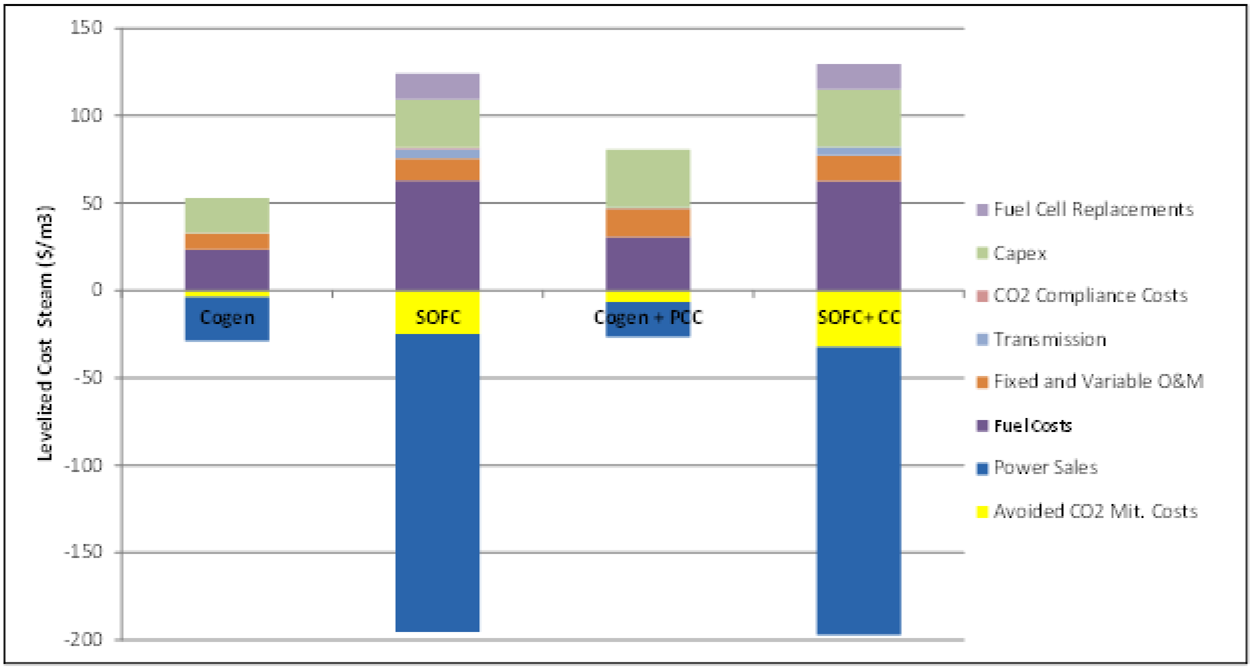


Table F-1 shows the numerical values for the components in Figure F-1 above.

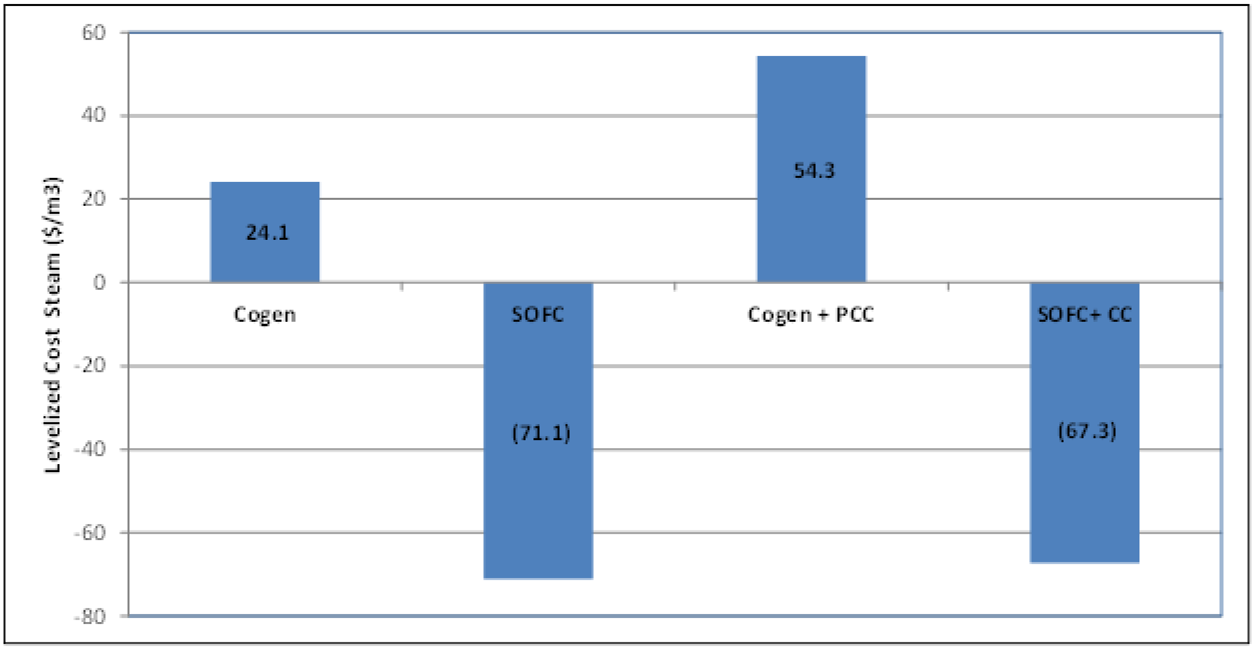
Table F-1.
Levelized Cost of Steam

	Cogen	SOFC	Cogen + PCC	SOFC+ CC
Avoided CO2 Mit. Costs	-3.7	-25.0	-6.6	-32.4
Power Sales	-25.2	-170.4	-19.9	-164.6
Fuel Costs	23.5	63.1	30.6	62.5
Power Purchases	0.0	0.0	0.0	0.0
Fixed and Variable O&M	9.1	12.7	16.3	14.7
Transmission	0.0	5.1	0.6	4.9
CO2 Compliance Costs	0.4	1.2	0.0	0.0
Capex	20.0	27.4	33.3	32.7
Fuel Cell Replacements	0.0	14.8	0.0	14.8
Total Cost of Steam	24.1	-71.1	54.3	-67.3

Figure F-2 below shows the net levelized cost of steam produced. Generally one would expect that because capturing CO_2 requires additional energy and equipment cost, the levelized cost of steam for cases with lower CO_2 emissions should be higher than their base case without CCS. This is clearly seen for Cogens. The SOFC case without CCS has the lowest levelized cost of steam. Adding carbon capture to the SOFC case slightly increases its levelized cost of steam.

Both SOFC cases provide negative costs for steam production because of the very high amount of power production provided.

Figure F-2.
Net Levelized Cost of Steam



Cost of CO_2 Capture

Figure F-3 shows the cost components that make up the cost to capture CO_2. The cost of capture is based on the incremental cost of CO_2 capture on the same steam production technology. The cost to capture CO_2 includes the cost to supply CO_2 at high pressure to a pipeline at the plant gate. The fuel cell replacement cost is not shown for the SOFC cases because it is a cost born by both the SOFC and the SOFC CCS case, and therefore it is netted out and is not incremental to CO_2 capture. Recall we have defined the cost of capture based on the incremental cost of completing capture on the base technology—in this case a SOFC—without CCS. For cogen, 32.7 MW of power has been used for carbon capture and is no longer available for sale (red bar). For SOFC, 33.3 MW of power has been used for carbon capture and is not longer available for sale (red bar). The dark blue bars on top of the X-axis for the Cogen and SOFC case indicate that less power is available for sale because a significant amount of it is required to capture CO_2.

The values in the graph below were derived by taking the difference in the cost of steam for each component found in Figure F-2 for a CCS case and its reference case, multiplying by 5,744,742 m^3/yr of steam, and then dividing by the mass of CO_2 captured as found in Table F-2.

Figure F-3.
Cost of CO_2 Capture

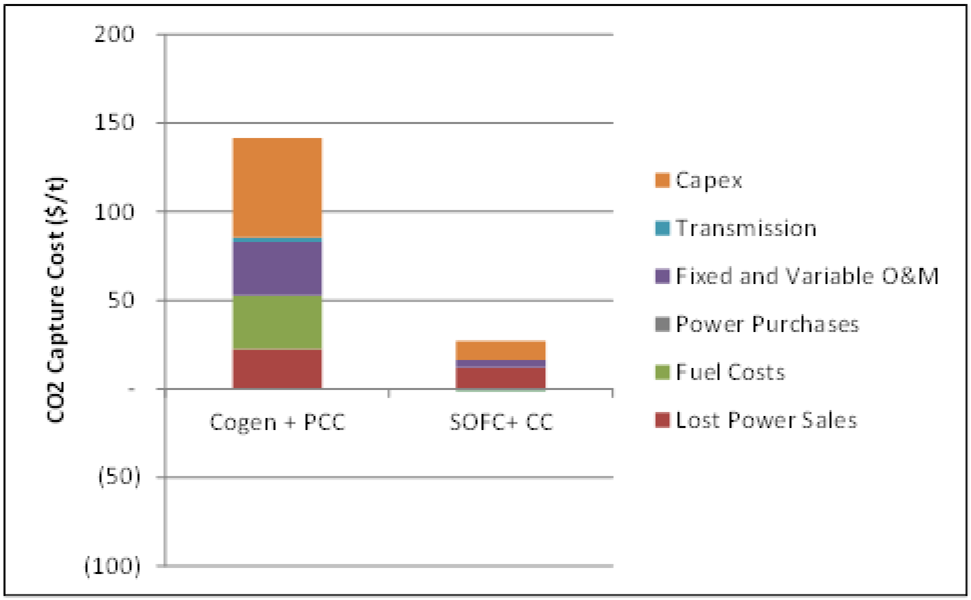


Table F-2 shows the components of costs and revenues which make up the cost of capturing CO_2 for all of the cases with CO_2 capture. The values in this table use a reference case of the underlying technology without CCS. For instance a SOFC without CCS was used as the reference case for the SOFC CCS case.

Table F-2.
CO_2 Capture Cost Components

	Cogen + PCC	SOFC+ CC
Lost Power Sales	22.5	12.0
Fuel Costs	30.0	-1.1
Power Purchases	0.0	0.0
Fixed and Variable O&M	30.5	4.2
Transmission	2.5	-0.4
Capex	56.2	10.9
Total Capture Cost	141.7	25.5

Figure F-4 shows the cost to capture CO_2 for the two CO_2 capture cases considered. These values were derived by assessing the cost of CO_2 capture on the same base option without CCS. The SOFC CCS case has the lowest cost of capture. The SOFC CCS case has a low capture cost because it does not cost much to purify the CO_2 produced by the fuel cell. As shown in Table F-3, the fuel cost component cost of steam with and without CO_2 capture, for the SOFC cases, is greater than the Cogen cases.

Figure F-4.
Net CO_2 Capture Costs

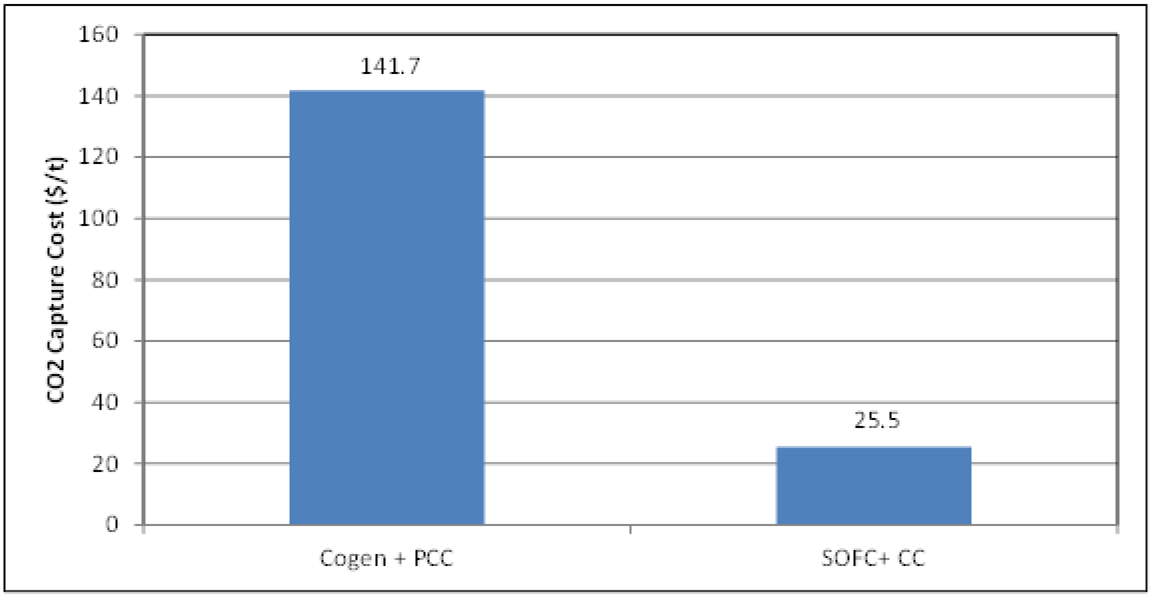


Table F-3 shows the values used to derive the mass of CO_2 avoided. For this table the reference case is the base technology without CCS. Avoided cost is the cost incurred to install and operate equipment to avoid these emissions.

As shown in Table F-3, CO_2 avoided is equal to CO_2 Captured, less CO_2 associated with power used to capture CO_2, plus credits associated with additional power generated less extra fuel used to produce steam used to capture CO_2. For the SOFC cases, less power is sold to the grid because some is used to capture CO_2. Incremental fuel use to produce steam is determined by comparing the emissions associated with fuel use in the base case without CCS to the case with CCS.

Generally the reference case used to calculate the cost of capture is what one would otherwise build. For instance, one would not build an IGCC with CCS because the cost is too high. Therefore, generally a supercritical coal plant without CCS is used as the reference case. If it is assumed that one would otherwise build an OTSG, then the capture cost for the Cogen becomes $97/t and **-**$150/t for the SOFC.

Table F-3.
Components of CO_2 Avoided

	Cogen + PCC	SOFC+ CC
CO2 Captured	1,359,260	2,779,475
Add: Credits for Power Gen. (t/yr)	-252,078	-256,703
Base Technology Fuel Use wo CCS	1,174,205	2,830,575
Fuel Use with CCS	1,510,370	2,780,205
Less: Incremental Fuel Use	336,165	-50,370
CO2 Avoided	771,017	2,573,142

Figure F-5 shows the components contributing to the avoided cost of CO_2. The values in the Figure F-5 below were derived by taking the difference in the cost of steam for each component found in Table F-1 for the CCS and the reference case and multiplying it by 5,744,742 m^3/yr of steam and then dividing by the mass of CO_2 avoided, as found in Table F-3.

Figure F-5.
Avoided CO_2 Costs

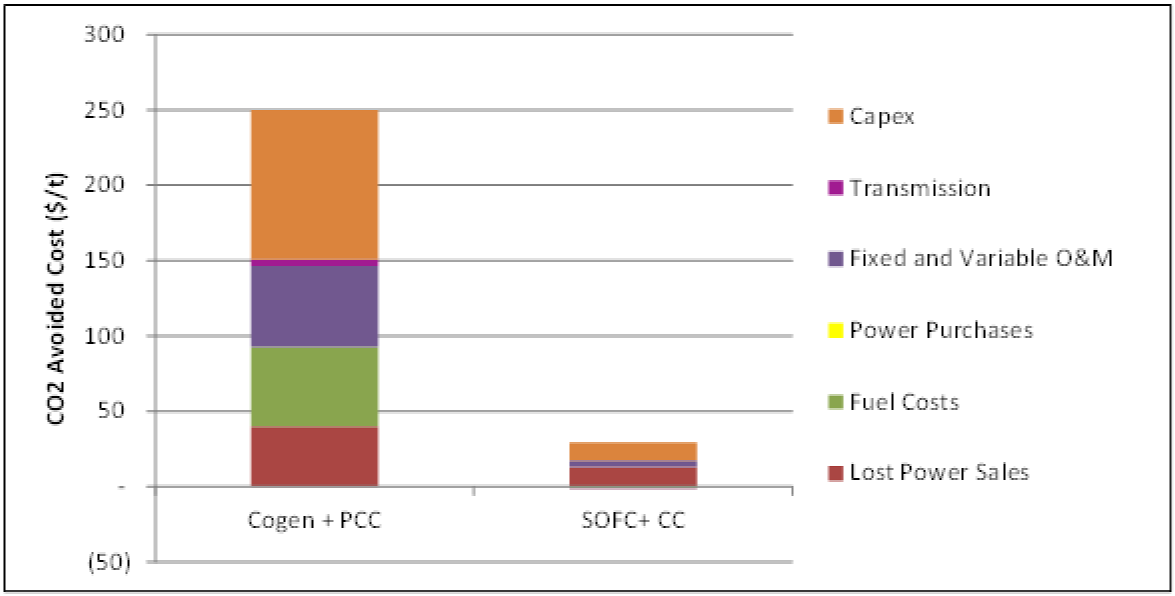


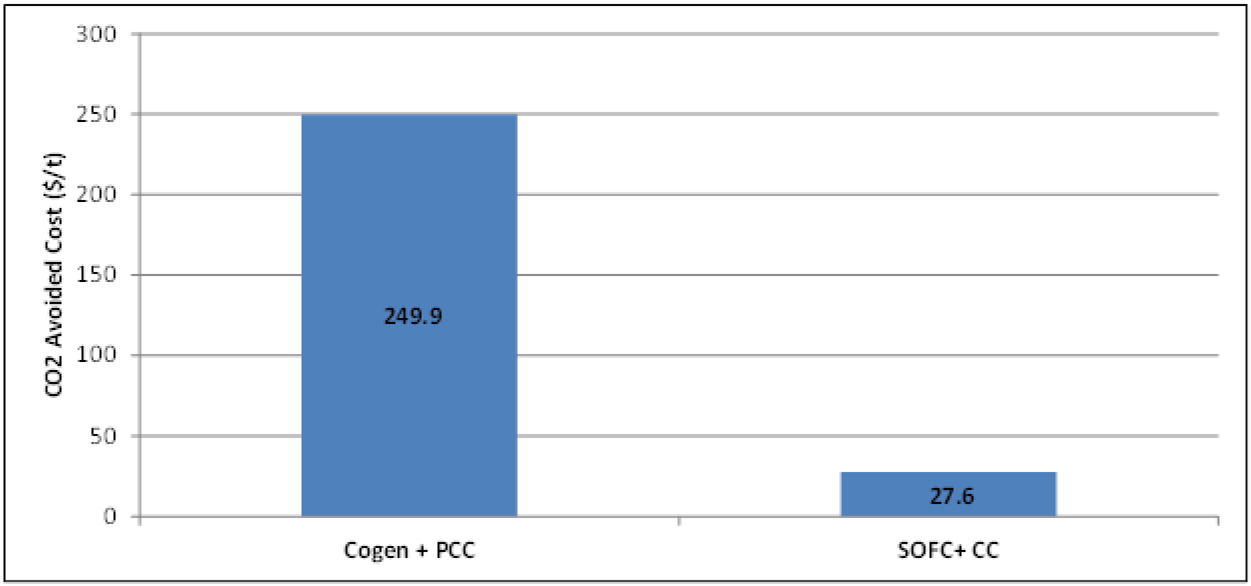
Table F-4 shows the components of costs and revenues which make up the avoided cost of CO_2 for both of the cases with CO_2 capture. The values in this table use a reference case of the underlying technology without CCS. For instance a SOFC without CCS was used as the reference case for the SOFC CCS case.

Table F-4.
Avoided Cost Components

	Cogen + PCC	SOFC+ CC
Lost Power Sales	39.7	12.9
Fuel Costs	52.9	-1.2
Power Purchases	0.0	0.0
Fixed and Variable O&M	53.7	4.5
Transmission	4.4	-0.4
Capex	99.0	11.8
Total Avoided Cost	249.9	27.6

Figure F-6 shows the avoided cost of CO_2 for the two CO_2 capture options. The SOFC CCS case incurs little cost to purify the CO_2 produced by the fuel cell.

Figure F-6.
Avoided CO_2 Costs



Economic Sensitivities

Introduction

This Study was based on, in some cases, fairly uncertain costs given that some of the technologies are emerging or early in commercialization. In addition, the operational characteristics over the long term are not well known. The economics of many of these cases are highly dependent upon the price forecasts for CO_2 credits, natural gas, and power.

Therefore, several sensitivities were constructed to compare the economic results for a range of assumptions.

Natural Gas Prices

The SOFC options have a very high fuel cost component compared to the other cases. It is expected that the cost of steam for these cases would be very sensitive to changes in natural gas prices.

Figure F-7 shows how the cost of steam is expected to change as the price of natural gas changes. The base natural gas price used in the economic modeling is \$5.00/GJ HHV. Clearly the SOFC cases are most sensitive to changes in natural gas prices. The relative ranking of the options remains the same at all gas prices considered. Figure F-7 suggests that the price of natural gas would have to exceed \$10.00/GJ before the SOFC cases would have a cost of steam greater than zero.

Figure F-7.
Natural Gas Price Sensitivity

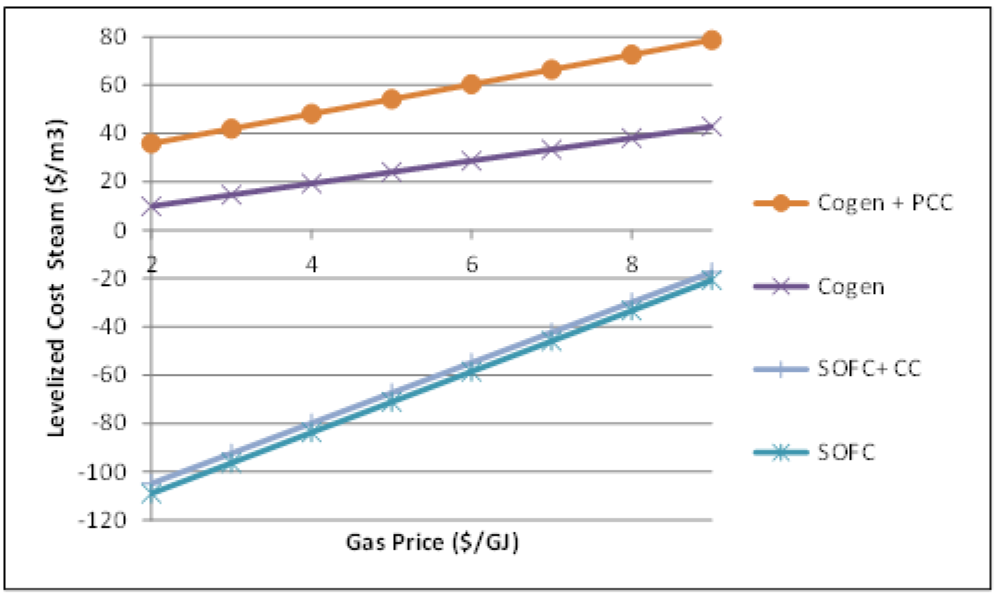
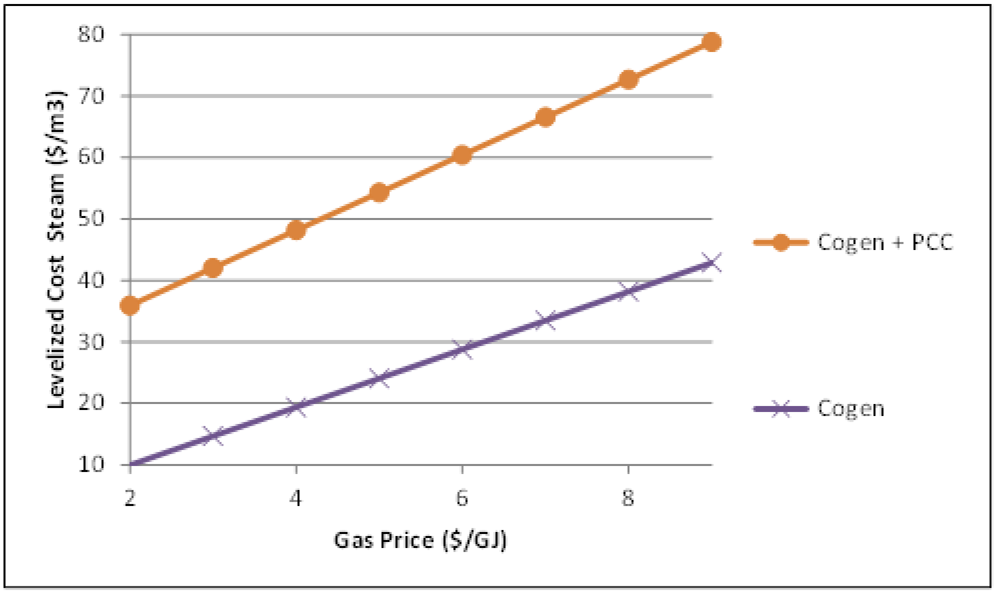


Figure F-8.
Natural Gas Price Sensitivity – without SOFC



Power Price Forecast

Power consumption in Alberta is expected to continue to grow by about 300 MW per year. Over the next 15 years, several thousand MW of coal plants may be decommissioned. The SOFC cases considered would bring over 900 MW onto the system over a short period of time. Generally, if more power is brought onto the system compared to load growth, the price of power will decrease. Bringing large amounts of SOFC power onto the grid along with other new power projects could suppress the power price. If the price of power is suppressed, then the economics of the SOFC cases could be less attractive.

The SOFC cases have a very large component related to power sales. Therefore, the economics of these cases should be sensitive to changes in power price. If the cost of steam is zero or no steam is made available, the cost of power is $50/MWh for the SOFC cases.

Cogen units generally price steam similar to that for an OTSG and then determine the required selling price of power to yield a reasonable return. The Cogen case would have to sell its power for about $50/MWh to have a similar cost of steam as an OTSG. This is low compared to other assessments of the required selling price of power for cogens. However, if steam is priced to provide a 20% discount to that of an OTSG at about $40/t steam, then the required selling price of power for the Cogen rises to about $80/MWh. Cogen units are one of the lowest-cost forms of new generation. They may set a floor price on the cost of power over the long term.

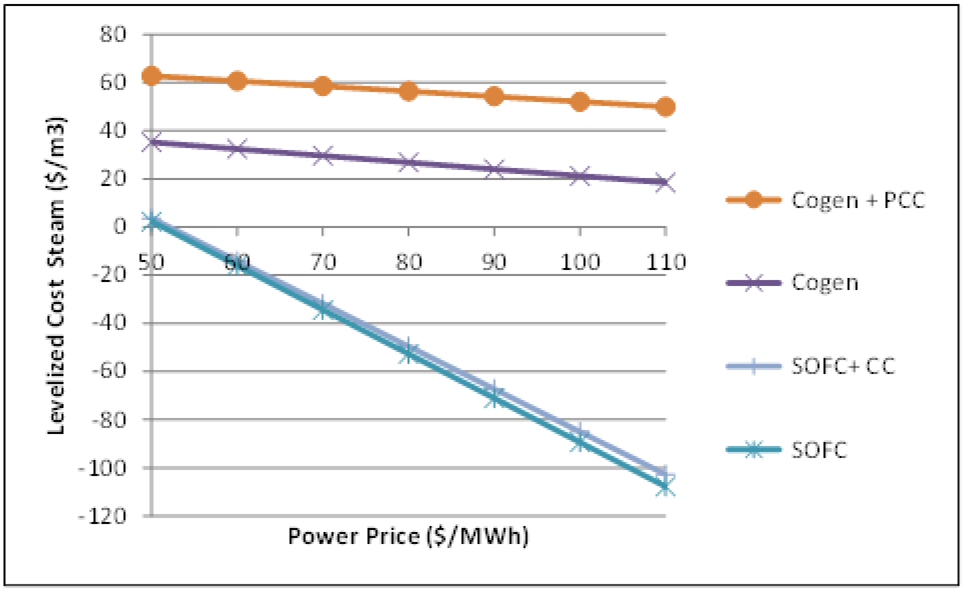
Many companies in the oil industry have decided not to build Cogens to supply steam even though they may have better economics than OTSGs. Oil and gas companies may not be willing to invest the additional capital required to support a Cogen, preferring to allocate capital to other opportunities. The SOFC cases considered require approximately 30% more capital for the same amount of steam production as the Cogen case.

In addition, oil and gas companies may not be interested in selling large quantities of power or working with power utilities to do so. For these reasons oil and gas companies may not want to allocate capital to sell large quantities of power from SOFC. In addition, the owners of a large SOFC project will assume significant exposure to the volatile power market in Alberta. Historically Cogens have faced the situation where off-peak prices were insufficient to recover fuel costs. Figure F-9 shows that the fuel chargeable to power heat rate of the SOFC cases is relatively low compared to the other cases, helping to mitigate this issue.

The proportion of power produced relative to steam can however be reduced in a number of ways. First, power could be used in electric boilers to produce steam. This would reduce the overall size of the project, reducing power production even further. However, an OTSG requires about 2.16 GJ to produce one m^3 of steam. The cost to produce one m^3 of steam with natural gas is about 2.16 GJ/m3 X \$5.00/GJ = \$10.80/m^3. If we assume an electric boiler is 100% efficient and the OTSG is only 85% efficient, then an electric boiler will require 1.84 GJ to produce one m^3 of steam. There are 3.6 GJ/MWh; therefore, 1.84 GJ/m^3 / 3.6 GJ/MWh = .51 MWh/m^3. Assuming the power price is \$90/MWh, then the .51 MWh/m^3 X \$90/MWh = \$46/m^3. Thus, using power to generate steam will cost about four times more than using gas. The price of power would have to drop to about \$20/MWh before using power to create steam would make economic sense. However, there are new developing technologies where electricity can be used to heat oil under the ground.

In addition, as a technology, the SOFC is designed to produce as much power as possible for a given amount of fuel and to reduce heat not used for other purposes. There may be other SOFC designs or configurations that will produce more heat for steam production and less power, but they were not analyzed as part of the scope of this Study.

Figure F-9.
Power Price Sensitivity

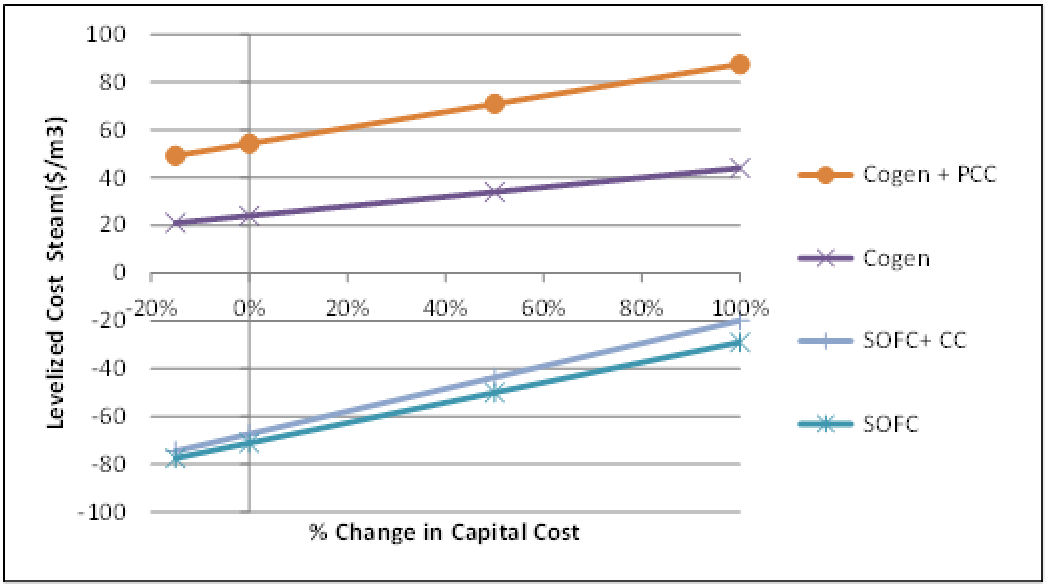


Capital Cost

Given that some of the technologies evaluated have not been mass produced on the scale required of the options considered in this Study, there is some uncertainty about the capital costs of these technologies. Figure F-10 shows how the cost of steam changes as the capital cost changes.

As shown above, SOFC CCS had the largest component cost associated with capital, followed by Cogen and SOFC. It is expected that the cost of steam for the SOFC CCS case should change most with changes in capital cost. However, as shown in Figure F-10, the relative ranking of all the cases is generally preserved over a wide range of changes in capital cost. The SOFC cases have the lowest cost of steam even with a 100% increase in the capital costs. This graph is based on the assumption that both the underlying steam production equipment and the carbon capture equipment both increase in costs.

Figure F-10.
Capex Sensitivity



The current cost for SOFC is high compared to other forms of power generation. The expectation is that once SOFCs are mass produced their capital cost should decrease substantially. The capital cost of SOFC provided by the vendor was $900/kW; this is substantially lower than current prices. This value was escalated to $1,500/kW to account for costs in Alberta and U&O. Figure F-11 shows how the cost of steam increases as the cost of SOFC increases. Current costs of steam with an OTSG are close to $40/t.

Figure F-11.
Steam Costs Relative to Capex Sensitivity

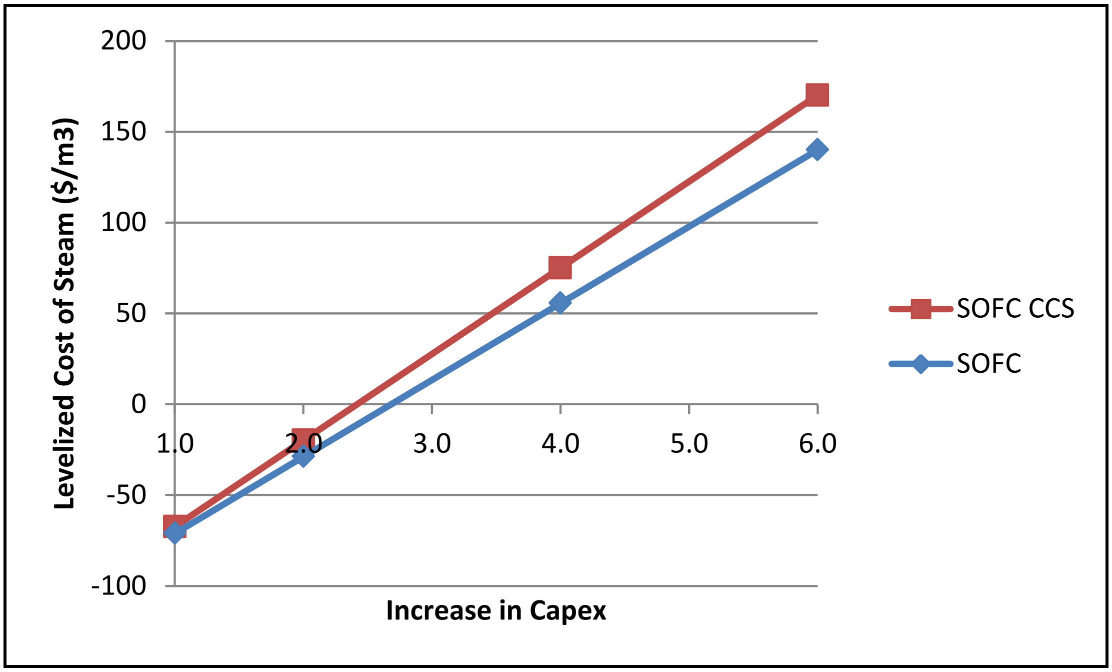


Figure F-11 shows how the cost of steam increases for increases in the whole cost of the plant, including the steam production equipment. Table F-5 shows the increase in steam cost for just a 100% increase in the capex for the CO_2 capture equipment. The first three rows show the base steam cost, the portion related to capital costs for CO_2 capture equipment, and the steam cost with the additional 100% increase in the capital cost for the CO_2 capture equipment.

The middle part of the table shows the base cost of CO_2 capture, plus the capture cost component related just to capture capital followed by the cost of CO_2 capture with a 100% increase in the cost component related to CO_2 capture capital.

The final part of this table shows the same analysis as for the avoided cost of CO_2 capture.

Table F-5.
Capex Sensitivity

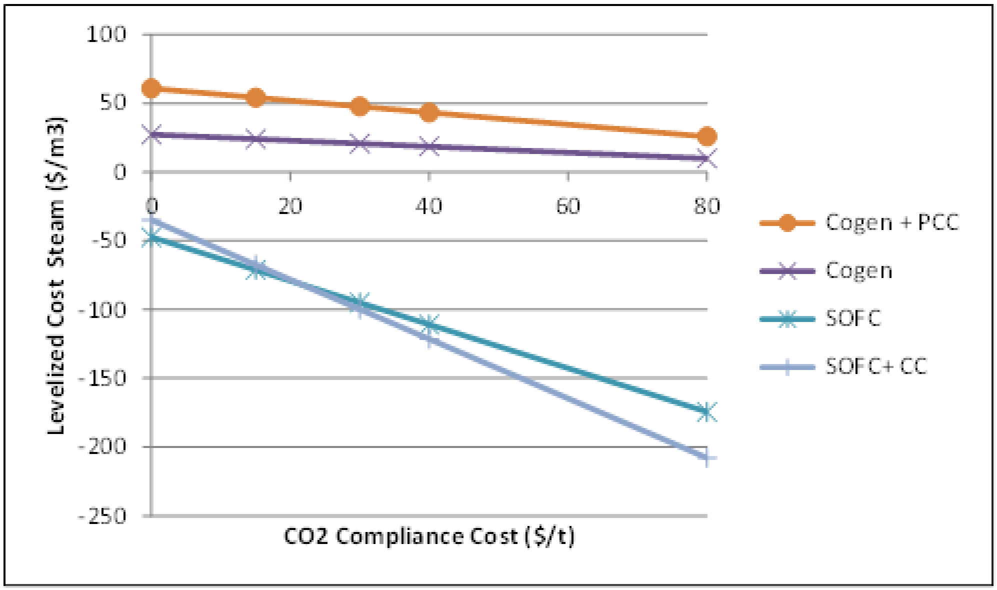
	Cogen + PCC
Base Steam Cost ($/m3)	54.3
Capex ($/M3)	13.3
Steam Cost +100% Inc. in Capex ($/m3)	67.6
Base CC ($/t)	141.7
Capex CC ($/t)	56.2
Capture Cost +100% Inc. in Capex ($/t)	197.9
Base Avoided Cost ($/t)	249.9
Capex Avoided ($/t)	99.0
Avoided Cost +100% Inc. in Capex ($/t)	348.9

CO_2 Compliance Costs

There is a significant amount of uncertainty regarding the cost to mitigate GHG emissions. Currently industry must mitigate about 12% of its GHG emissions and can do so by paying the CCEMC $15/tonne. Figure F-12 shows the impact of changes in the carbon price on this 12% of emissions to be mitigated. As explained above, the SOFC cases had a very large benefit associated with the value of credits sold from green power. Therefore, as shown in the graph below, the cost of steam for the SOFC cases changes most for the SOFC cases.

An increase in the CO_2 compliance cost materially decreases the cost of steam for the SOFC cases. Even over a wide range of the compliance costs the relative ranking does not change. Increasing compliance costs decrease the cost of steam for all cases because they sell credits. The compliance cost for a 40% reduction in emissions and a $40/t carbon price would be $133/t on the following graph. The cases producing CO_2 credits related to CO_2 capture or for power sales have large volumes of CO_2 multiplied by $15/t. Therefore, they are sensitive to CO_2 compliances costs. Figure F-12 shows that the mass of credits available is in some cases an order of magnitude greater than the direct compliance requirement.

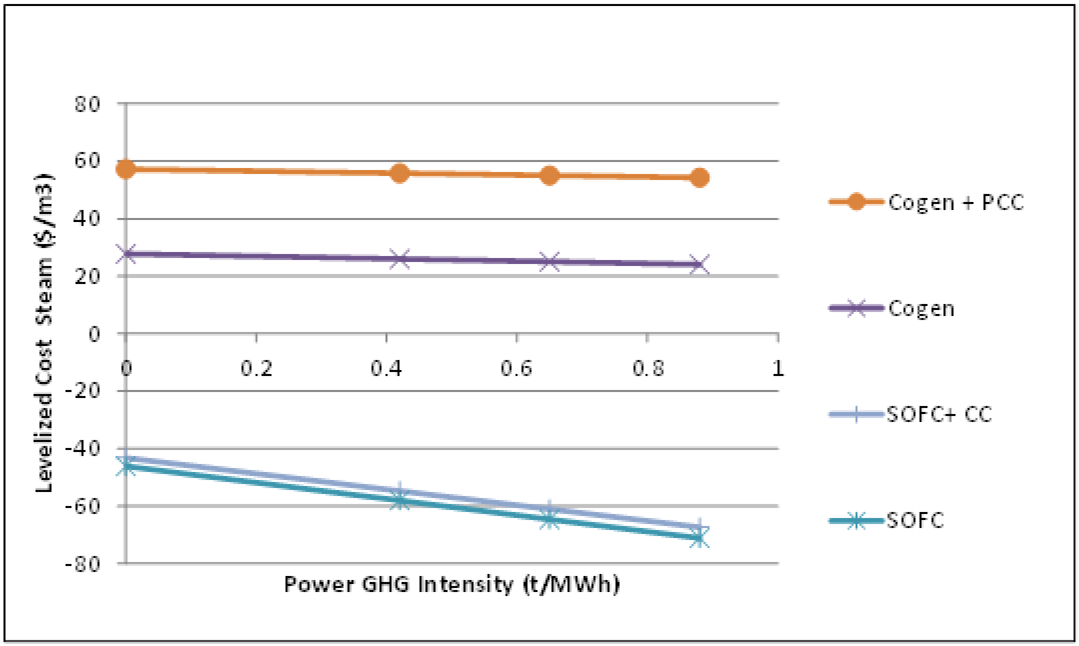
Figure F-12.
CO_2 Compliance Cost Sensitivity



Emission Intensity for Power

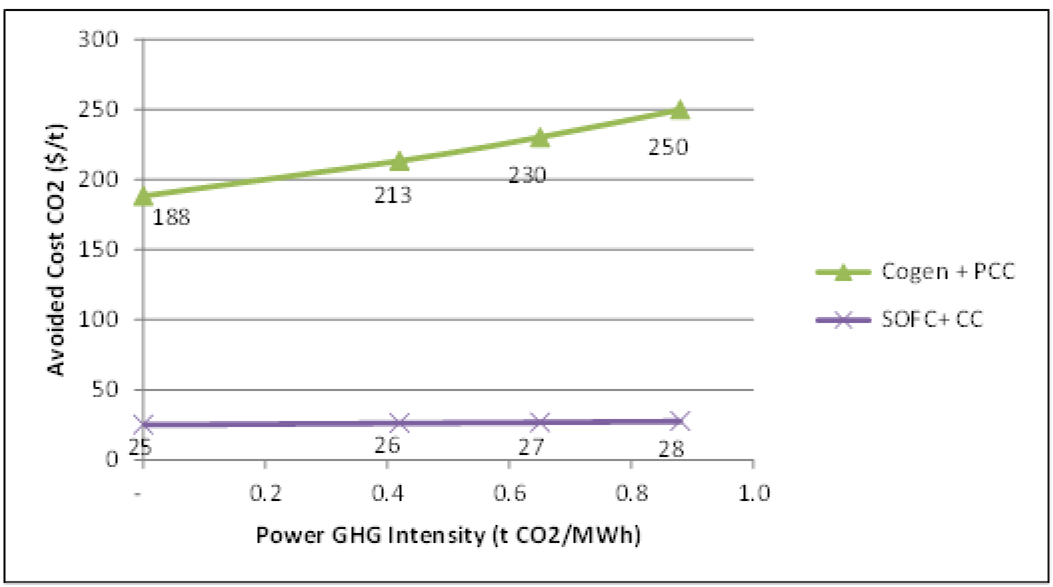
Currently in Alberta the grid emission intensity is about 0.88 t/MWh due to the high proportion of power generated by coal plants with high emission intensities. Power plants selling green power are provided GHG credits based on 0.65 t/MWh. Figure F-13 shows what would happen if the GHG emission intensity used to quantify GHG credits for green power changed. As expected, the SOFC cases are very sensitive to changes in the emission intensity. Even if power is not providing any CO_2 credits, the SOFC cases have the lowest steam production costs.

Figure F-13.
Impact of CO_2 Credits for Power Export Sensitivity



The GHG intensity of power will also have a substantial impact on avoided cost. Figure F-14 shows how the avoided cost of CO_2 changes as the GHG emission intensity of power ranges from 0 to 0.88 t/MWh.

Figure F-14.
Sensitivity to Power Generation CO_2 Intensity

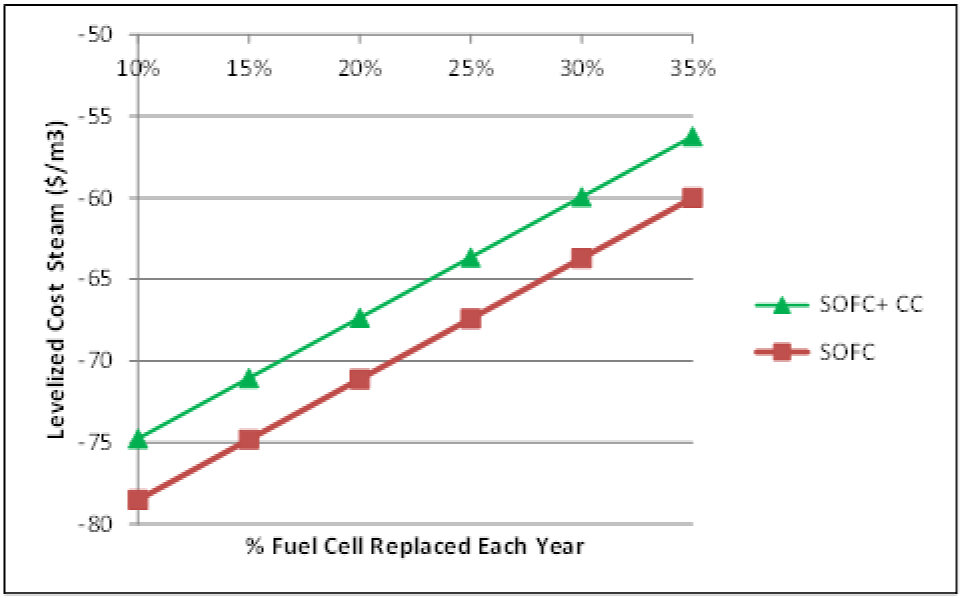


Fuel Cell Replacement

SOFCs are installed in equal portions over a 3-year period prior to January 1, 2016. When the first third of capacity is installed in 2013, it is assumed to produce power in 2014. When the next third of capacity is installed in 2014, two-thirds of the ultimate installed capacity is assumed to be producing power in early 2015. However, it is unlikely that the required amount of fuel cells can be installed in 2013. Therefore, the in-service date for the SOFC cases should likely be moved into the future beyond January 1, 2016.

However, SOFCs are only expected to operate for about five years, at which point the power production will decrease by about 10 percent. As such, beginning in 2018, 20% of the fuel cell capacity is replaced each year. The manufacturer believed the expected life can be increased to ten years in the future. Therefore, a sensitivity on fuel cell life is shown in Figure F-15. The replacement cost of fuel cells for the SOFC cases is sensitive to changes in the pace of replacement.

Figure F-15.
Fuel Cell Replacement Cost Sensitivity



Economic Conclusions

The SOFC cases offer the greatest reduction in emission intensity largely due to the credit for power export. However, the emissions associated with steam and power production can be allocated in different ways, so other allocation options may yield lower emission intensities for steam. The cost of CO_2 capture for the SOFC cases is very low. The SOFC cases also have a very low cost of steam production due to the large amount of power produced.

One of the issues associated with the SOFC cases is the large amount of power produced and the large capital outlay required.

In Table F-6, the term “EI” represents emission intensity. Direct emission intensities assume all GHG emissions from the plant are allocated to steam. The D&I row assumes that in addition to direct emissions, GHG emissions associated with power purchases are added and GHG emissions associated with power sales are deducted in the calculation. (Negative intensities may not be allowed.)

Table F-6.
Economic Summary Data

	Cogen	SOFC	Cogen CCS	SOFC CCS
Direct EI (t CO_2/bbl)	.097	.235	.013	.000
D&I EI (t CO_2/bbl)	-.002	-.378	-.066	-.591
COS ($/$m^3$)	24.1	-71.1	54.3	-67.3
Capture Cost ($/t)			141.7	25.5
Capex $000’s	1,054,536	1,426,060	1,755,757	1,699,917
Power (MW)	155	957	122	924

Other Metrics

Energy Required for Capture

One of the key metrics for assessing the cost of post combustion capture technologies is the amount of energy required to capture one tonne of CO_2. Table F-7 shows this energy requirement. The first case is for a solvent-based CO_2 capture system. The SOFC CCS case is based on a system using oxygen to burn out the unused fuel left in the CO_2. These values are based on the difference in natural gas consumption between the CCS case and the relevant base technology without CCS divided by the mass of CO_2 captured in a given year.

Table F-7.
Energy Required for Capture

	Cogen CCS	SOFC CCS
Energy (GJ HHV / t CO_2)	5.1	(.2)

GHG Emission Intensities

One of the key metrics used to assess the GHG emissions associated with oil production is the GHG emission intensity. The emission intensities shown in Table F-9 relate just to the GHG emission associated with the production of steam used to recover oil. For the cases with CO_2 capture, the emissions are those that occur because the CO_2 capture system was unable to capture emissions related to steam production used to recover oil and steam produced to capture CO_2. Emission intensity is the mass of CO_2 emitted divided by the barrels of oil produced in a year.

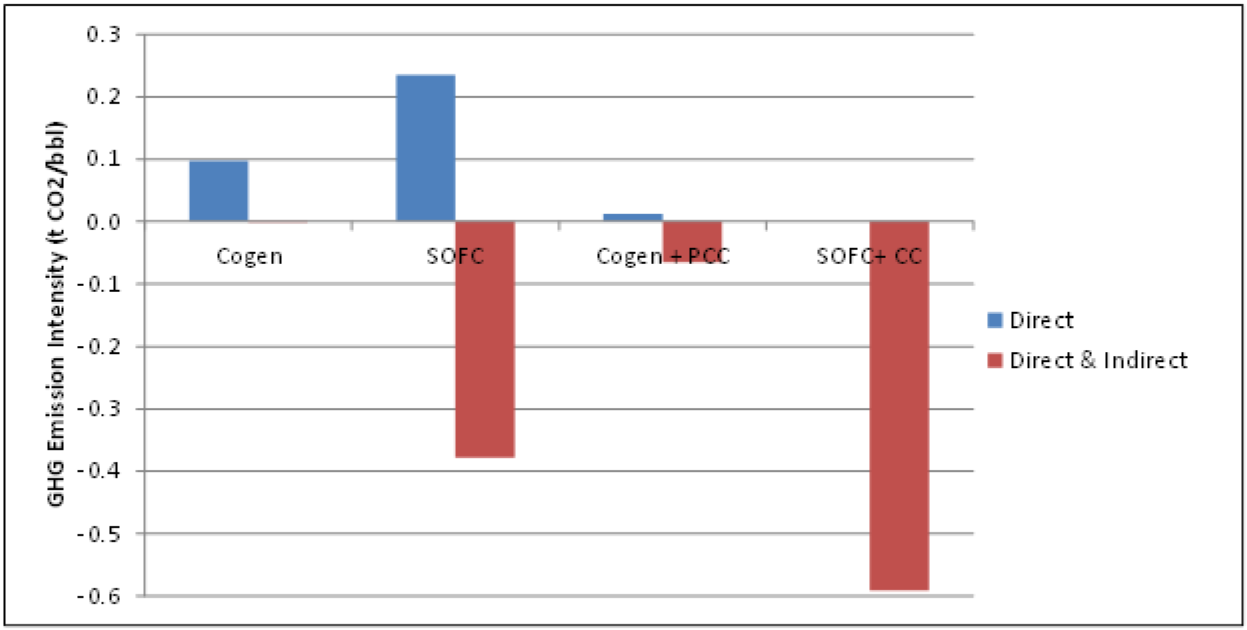
There are two emission intensity values reported in Table F-9. The first is related to the direct CO_2 emissions for an option. Direct emission intensities are based on the mass of CO_2 emitted. The Direct and Indirect intensities include the direct CO_2 emissions from the plant, plus indirect CO_2 emissions associated with power used to capture CO_2 or credits from additional power produced by the capture option at a rate of 0.88t/MWh. Some of the cases have negative GHG emission intensities because these cases produce a significant amount of additional power and GHG credits. However, generating a negative emission intensity for steam production may not be permitted. The SOFC case has a high direct emission intensity largely because a significant amount of the natural gas used in the fuel cell is used to produce power.

Table F-9.
GHG Emission Intensities in tonnes of CO_2/bbl of Oil

	Cogen	SOFC	Cogen CCS	SOFC CCS
Direct	.097	.235	.013	.000
Difference on OTSG	-.044	-.182	.041	.053
Direct & Indirect	-.002	-.378	-.066	-.591

Emission Intensity in Figure F-16 below shows the emission intensity of steam used to recover oil. The blue values are the direct CO_2 emissions. The red bars include the indirect emissions associated with power purchases, and sales are included based on 0.88 t/MWh.

Figure F-16.
Direct and Indirect Emission Intensity of Steam



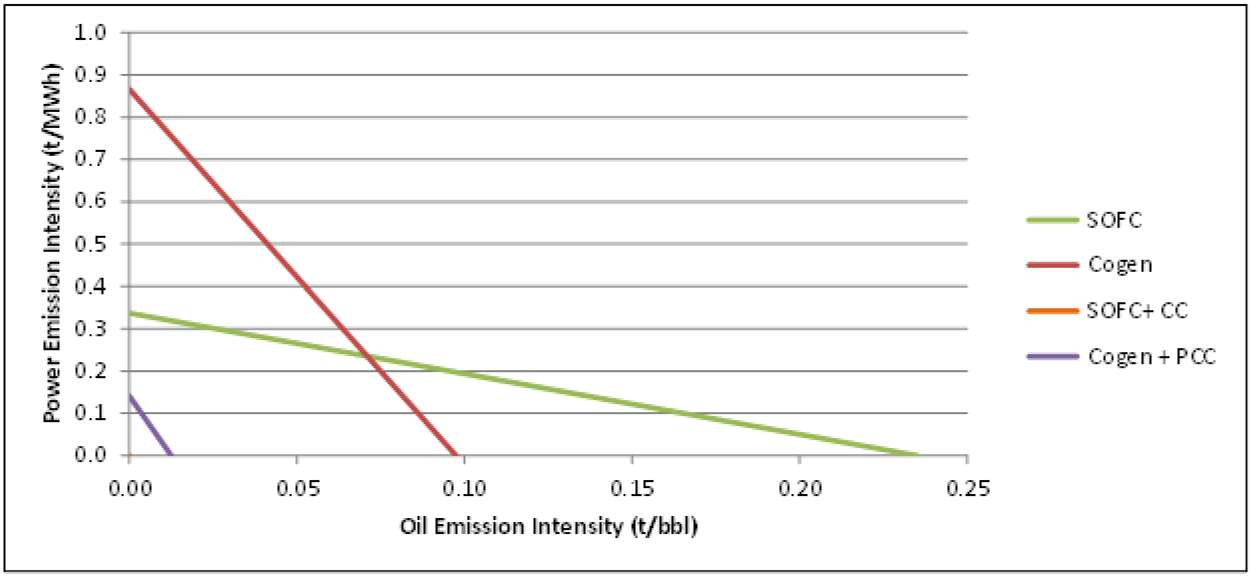
All of the CO_2 emissions from the plant are attributed to the production of steam and none to power in Table F-8 above. For this reason, any power produced will have a GHG emission intensity of zero and will generate GHG credits in the power market. However, if some of the GHG emissions are attributed to power, then the emission intensity of steam production will fall. The point is that there are two legitimate commodities being produced. There is no reason all the GHG emissions need to be allocated to steam production; in fact, doing so may overestimate the GHG emission intensity of the steam produced. The Direct & Indirect values in Table F-9 are based on credits generated based on 0.88 t/MWh of power sold or to power purchases avoided. Table F-10 shows the GHG emission intensities for power assuming no GHG emissions are allocated to steam produced and all of the GHG emissions are allocated to power produced. To be clear, the GHG emission intensity of the steam produced would be zero. The SOFC cases would likely still generate credits in the power market.

Table F-10.
GHG Emission Intensity Assuming All Emissions Allocated to Power

	OTSG ECM	Cogen	SOFC	Cogen CCS	SOFC CCS
Intensity (t/MWh)	.11	.87	.34	.14	.00

However, emission intensities will likely have to be greater than or equal to zero. Therefore, one could use a value between 0.0 t/MWh and 0.88 t/MWh and back out the GHG emission intensity for steam. Figure F-17 shows the range in emission intensity for power sales and steam for oil production. The values on the X axis assume all direct GHG emissions are allocated to steam and none to power. All the values on the Y axis assume all direct GHG emissions are allocated to power production and none to steam. The value for the SOFC CCS case is zero because close to 100% of the CO_2 generated is captured.

Figure F-17.
Range of Emission Intensity



For Cogens, credits are created based on deducting reasonable emission values associated with the CO_2 that would have otherwise been emitted to produce the steam supplied. If an emission intensity of 0.053 t/bbl of steam is applied to a Cogen, then from the graph above power would have an emission intensity of about 0.39 t/MWh. The power emission intensity of 0.39t/MWh for the Cogen case is similar to values derived for other projects. The SOFC emission intensity for power at 0.053t/bbl is 0.26 t/MWh. There may be an economic optimum allocation of GHG emissions between oil and power.

GHG Credits Generated

As discussed previously, there are two sources of CO_2 credits. The first is related to the reduction in GHG emissions associated with CO_2 capture, and the other is related to the production of incremental power. Emissions related to CO_2 capture are predicated on the notion that one would have to mitigate 12% of one's emissions if no CO_2 capture occurred. An entity cannot sell credits for the mass of CO_2 it is obligated to mitigate. It can only sell credits for the mass of CO_2 it captures over and above its obligations to mitigate. Therefore, it is assumed that the baseline for this calculation would be the emissions that would have occurred if no CO_2 capture had been completed on the underlying technology without CCS. Given that all GHG emissions are allocated to the production of steam, all power sold to the grid is assumed to have a GHG emission intensity of zero and is therefore allocated 0.88 t CO_2/MWh of credits.

Table F-11 shows the values used to estimate the amount of GHG obligations and credits. Two sources of CO_2 emissions were considered in this assessment: direct CO_2 emissions and emissions associated with power used from the grid. The Direct Compliance requirement in the fifth row is 12% of the first row CO_2 Produced. It was also assumed that the entity producing steam will be obligated to purchase credits to mitigate GHG emissions associated with power usage from the grid. Generally speaking, this is the obligation of the power producer. The compliance requirement is the sum of the 12% emission reduction requirement and the GHG mitigation requirements associated with power purchases. CO_2 credits available for sale are based on the mass of CO_2 captured less 12% of the CO_2 generated plus credits associated with power sales.

Table F-11 also shows that if Cogens without CCS received 0.88t/MWh related to CO_2 credits in the power market, they could effectively offset all of the CO_2 emissions from the plant.

Table F-11.
Values Used to Derive GHG Obligations and Credits

GHG Production	Cogen	SOFC	Cogen + PCC	SOFC+ CC
CO2 Produced (t/yr)	1,174,205	2,830,575	1,510,370	2,780,205
CO2 Captured (t/yr)	-	-	1,359,260	2,779,475
CO2 Emissions (t/yr)	1,174,205	2,830,575	151,110	730
% Comp. Requirement (t/yr)	12%	12%	12%	12%
Compliance Requirement (t/yr)	140,905	339,669	-	-
GHG Compliance				
Direct Compliance Req. (t/yr)	140,905	339,669	-	-
GHG From Power Purchases (t/yr)	-	-	-	-
Compliance Requirement (t/yr)	140,905	339,669	-	-
GHG Credits				
Direct Reductions in CO2 (t/yr)	-	-	1,178,016	2,445,850
Credits for Clean Power Sales (t/yr)	1,192,551	7,379,634	940,474	7,122,931
Credits Available for Sale (t/yr)	1,192,551	7,379,634	2,118,489	9,568,782

Section G.

Findings and Recommendations

Findings

Based on the Study, Jacobs Consultancy's findings are summarized as follows:

- The Solid Oxide Fuel Cell ("SOFC") is a power producer with heat as a by-product and is a mismatch for thermal in-situ, which has a large heat load and small power load. A typical thermal in-situ plant has a demand of about 10 MW of heat for every MW (thermal equivalent) of power. An SOFC, on the other hand, produces about one MW of heat for every 7 MW (thermal equivalent) of power. This results in a mismatch of 70 to one as compared to the requirements for bitumen production. Any efforts to reduce the power-to-heat ratio on an SOFC just result in bypassing fuel around the anode side and combusting it with air which, in effect, is like having an OTSG to produce steam with a small SOFC to produce the power for the site.
- However, combined heat and power ("CHP") can be attractive for a thermal in-situ site provided a better match between heat and power. For example:
  - Conventional cogen produces steam with a cost about 40% lower than WLS+OTSG with a manageable amount of power sold to grid.
- CO_2 capture and compression increase the cost of producing steam.
- However, fuel cells are relatively cost effective for CO_2 recovery assuming power produced can be sold to grid
  - On paper, due to **very high power sales**, SOFC has capture and compression costs that are roughly one-fourth of conventional CHP with PCC (but again, there is a mismatch of heat and power for SAGD).

Recommendations

Our recommendations are summarized below:

- Focus efforts on SOFC as a power producer, not as a CHP technology for thermal in-situ plants
- Therefore, we recommend in the near term:
  - Feasibility studies on a commercial-scale plant to confirm capital costs and commercial viability for:
    - Cogen and OTSG-based thermal in-situ, SMR and Fired Heaters