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Repowering Options for Complying with Canadian CO_2 Emission Intensity Limits on Existing Coal Plants

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Abstract

The Canadian federal government has introduced carbon dioxide emission intensity limits of no greater than 420 kg/MWh net for new coal plants and existing coal plants more than 50 years of age. Many operating coal plants in Canada will be impacted by this legislation in the near future, requiring operators to plan a compliance strategy. The Canadian Clean Power Coalition (CCPC) investigated the performance and economics of a number of options for existing plants that could deliver compliant solutions. These options included strategies in which natural gas is available and some in which only coal firing is feasible due to cost or logistical issues.

Repowering and post-combustion capture (PCC) options were studied using an eastern Canadian power plant firing bituminous coal. The base-case (BC) option was a new combined-cycle gas turbine (CCGT) plant, against which all other options were compared. The following cases were investigated:

1. PCC using:
   a. Monoethanolamine MEA solvent with crossover steam regeneration
   b. Commercial advanced solvent with crossover steam regeneration
   c. Commercial advanced solvent with a small gas turbine (GT) and a low-pressure steam generator
   d. Commercial advanced solvent with a GT, triple-pressure heat recovery steam generator (HRSG) and a back pressure steam turbine
   e. Commercial advanced solvent with a natural gas boiler and a back pressure steam turbine
2. Repowering of existing steam turbines with new a GT and HRSG
3. Repowering of existing steam turbines with fuel cells

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   a. New solid oxide fuel cell (SOFC) topping unit
   b. New molten carbonate fuel cell (MCFC) topping unit
4. Expanded PCC approach with:
   a. Third unit with full LP steam turbine bypass supplying steam to PCC
   b. Circulating fluidized bed (CFB) boiler and back pressure steam turbine

One of the issues with incorporating PCC in an existing facility is delivering the thermal regeneration energy to the PCC reboilers in an efficient and cost-effective manner. This can involve significant integration with the low-pressure stages of the steam turbine, a duty for which the turbine was not designed. Because turbine modifications (to deliver partially expanded steam to the PCC plant) can be costly and would require significant down time, alternative strategies were investigated in which the PCC facility would effectively be a “standalone” facility, with the main plant interfaces being the flue gas to be treated and some shared services.

The costing analysis was carried out on the following basis: 30-year plant design life (with life-extension costs included for existing plant), 90% capacity factor for the first year cost of electricity (COE), and a coal cost of $4.73/GJ and a natural gas cost of $10.00/GJ (based on 2013 forecasted costs). Case 2 (repowering existing steam turbines with new natural gas combined-cycle plant) without any additional CO_2 abatement, delivered both the lowest capital costs and cost of electricity. If the existing coal boiler plant remains operational, the lowest costs were achieved by installing a molten carbonate fuel cell (Case 3b) followed closely with an advanced solvent PCC unit with solvent regeneration thermal energy being delivered by an efficient, small, dedicated gas turbine with a triple pressure HRSG (Case 1d). Where there is no existing infrastructure to deliver natural gas, the traditional methodology of extracting crossover steam from the unit for PCC solvent regeneration proved to be the lowest-cost option.

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Keywords: Power plant repowering, CO_2 capture, post combustion capture, techno-economics

1. Introduction

Observed climate change from the mid-20th Century has been attributed to anthropogenic activities and the associated emission of greenhouse gases (GHG) in to the atmosphere [1]. Carbon dioxide (CO_2) has been identified as a principle greenhouse gas which has been increasing in atmospheric concentration since the beginning of the Industrial Revolution. This increase in atmospheric CO_2 concentration has largely been attributed to the compounding impact of anthropogenic CO_2 emissions, the rate of which is accelerating as a result of global economic growth.

At the recent Conference of Parties meeting in Paris (COP21), world leaders sought to agree on a concerted pathway to limit the average global temperature rise to no greater than 2°C above pre-industrial levels [2]. Achievement of this goal will require significant decarbonization of many energy-intensive sectors of global society. Electric power generation has been identified as an important component in this strategy; high-emission-intensity methods of power generation can be targeted for reductions in emissions, either by switching to lower-intensity power generation technologies or by introducing carbon capture and storage systems to limit atmospheric release.

The Canadian Federal Government has already introduced carbon dioxide emission intensity limits of no greater than 420 kg/MWh net for new coal plants and existing coal plants which have achieved a “useful life” just under 50 years [3]. Many operating coal fired power plants in Canada will be impacted by this legislation in the near future, as early as December 2019 if they were commissioned before 1975. Hence this legislation is requiring operators to plan a compliance strategy for these aging assets. Operators need to establish what will be the lowest-cost repowering options moving forward for their plants, ranging from full replacement with new power equipment to the addition of emission control technology to meet the required emission intensity limit.

The Canadian Clean Power Coalition (CCPC) investigated the performance and economics of a number of options open to existing plants that would deliver compliance solutions. CCPC selected the Lingan Generating Station (LGS), located in the Canadian province of Nova Scotia, as the focus for the repowering study. A number of options were investigated, including strategies in which natural gas is available and some in which only coal firing is feasible due to cost or logistical issues of natural gas supply.

Nomenclature

$	Canadian dollar
AC	Avoided Cost (CO_2 emission)
ASL	Above Sea Level
ASU	Air Separation Unit
BC	Base Case
CAPEX	Capital Expenditure
CC	Cost of Capture (CO_2)
CCPC	Canadian Clean Power Coalition
CEPACS	Combined Electric Power and Carbon Dioxide Separation
CFB	Circulating Fluidized Bed
CO_2	Carbon Dioxide
COE	Cost of Electricity
EAB	Economic Analysis Basis
ECM	ElectroChemical Membrane
EOR	Enhanced Oil Recovery
EX	Existing Plant
FCE	FuelCell Energy, Inc.
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
GJ	gigajoule (energy)
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
LGS	Lingan Generating Station
MEA	Monoethanolamine solvent
MCFC	Molten Carbonate Fuel Cell
MWe	megawatt electric (power)
MWh	megawatt-hour (energy)
Nm^3/h	Normal cubic metres per hour (0°C/1atm)
NPV	Net Present Value
OPEX	Operating Expenditure
PCC	Post-Combustion Capture
ppmv	parts per million by volume (concentration)
SOFC	Solid Oxide Fuel Cell

Disclaimer

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2. Repowering

2.1. Plant Selection: Lingan Power Station

The Lingan Generating Station is a coal-fired plant in the Cape Breton Regional Municipality in the northern part of the Canadian province of Nova Scotia. Opened in late 1979, the facility is operated by Nova Scotia Power and currently has 4 identical boiler/turbine units capable of generating a total combined maximum output of 616 MWe by burning bituminous coal. The investigation considered the options available to Nova Scotia Power in which 2 of the units have been decommissioned and the remaining 2 need to be available for generation whilst being compliant with the GHG emission intensity limit. Repowering options were sized on the following basis:

- Replacement plant will deliver at least the same net output as 2 existing units (totaling 309 MWe)
- Retrofitted carbon abatement is sized to deliver the overall 420 kg/MWh net GHG emission intensity limit
- Auxiliary plant needed to drive abatement plant shall be sized no greater than needed to energize the abatement plant – additional power may be produced in conjunction with the required quantity of heat generation needed

The replacement plant options represent a fuel substitution from coal to natural gas; whilst this may not be directly suitable for LGS, in other areas of Canada it is very relevant as a repowering option due to convenient access to natural gas supply.

2.2. Repowering Options

A number of options were identified as feasible strategies for delivering low-cost systems that could be compliant with the Canadian CO_2 emission intensity limit. A base case (BC) option was developed which involved installing a complete replacement natural gas combined-cycle (NGCC) plant, switching from coal to natural gas as fuel supply. A GE 7F.05 operating in combined cycle was selected for this duty, capable of generating up to 320 MWe, with an inherent performance resulting in a lower CO_2 emission intensity than required by the Canadian legislation for coal plants, and so represents a straightforward replacement option (subject to spatial constraints and the availability of natural gas).

The first repowering strategy was based on the addition of post-combustion CO_2 capture systems that could reduce the emission intensity of the overall plant to achieve compliance. Post-combustion capture (PCC) processes are typically carried out using an alkanolamine solvent which can selectively absorb CO_2 from the flue gases and release it at a high purity when regenerated using low-temperature heat. The efficiency impact of this process on the overall power plant depends on the capabilities of the solvent (stability, CO_2 capacity, regeneration energy, etc.) and the synergies possible in delivering the thermal energy to the capture process and recovering heat from the process and downstream CO_2 compression systems.

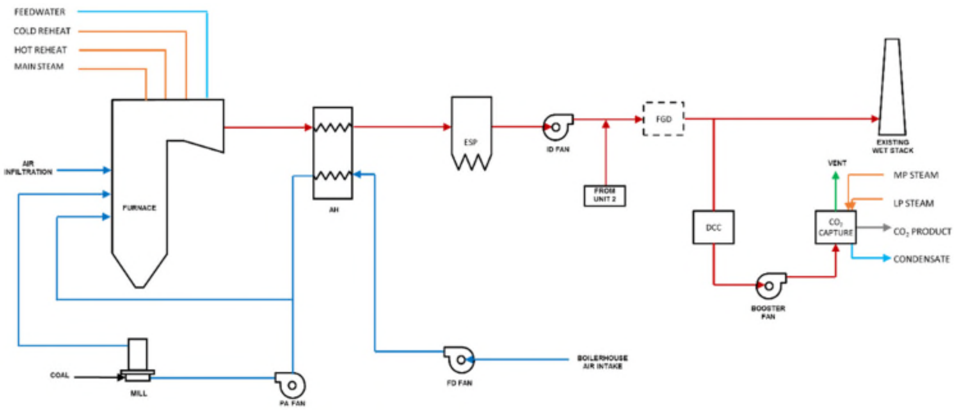


Figure 1. LGS Boiler Island with Capture Plant

There also are significant challenges when integrating PCC with an existing power plant system, namely the difficulties with extracting low-pressure steam from the steam turbine system and the impact of removing that steam on the lower-pressure stages of the steam turbine. One way to minimize this risk to the existing plant is to include a new a dedicated thermal delivery system with the PCC process, thereby decoupling the existing steam system from the PCC plant. The study therefore considered a number of possibilities to identify the lowest-cost options available:

1a. MEA solvent with crossover steam regeneration

This represents a conservative PCC baseline case in which the solvent being considered is the industry standard monoethanolamine (MEA) solvent which has been used in the gas sweeting industry for CO_2 capture for more than 50 years. MEA solvent presents significant thermal energy requirements for solvent regeneration and can undergo significant degradation due to acid gas reactions, thermal decomposition, and oxidation-based degradation. Specialized inhibitor chemicals can be added to reduce, but not eliminate, this degradation. The regeneration energy is sourced from the steam turbine, reducing the output power that can be generated by the low-pressure (LP) turbine stages. Because the imposed load of MEA PCC reduces the net power plant output, additional capture capacity is needed to reach the 420 kg/MWh intensity limit.

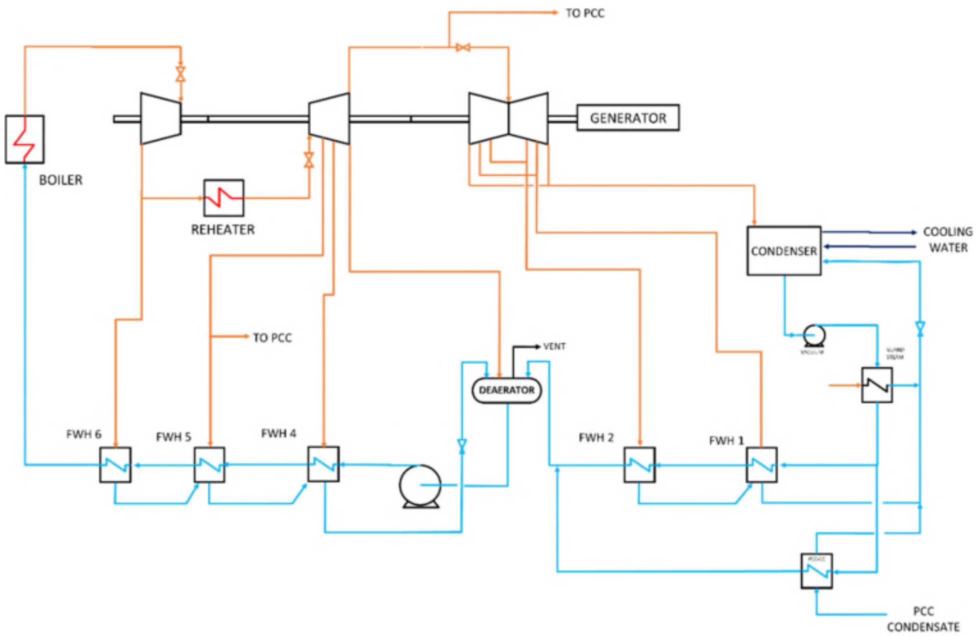


Figure 2. LGS Steam Turbine Island with Steam Extraction (Cases 1a/1b)

1b. Commercial advanced solvent with crossover steam regeneration

Similar to Case 1a, the PCC process is added to the existing coal-fired power plant and is regenerated using steam from the steam turbine; however, the thermal energy requirements are lower due to the application of an advanced solvent. Because the imposed load of this case is lower than that of Case 1a, the PCC process can be sized smaller, which further reduces the imposed load and also reduces capital costs.

1c. Commercial advanced solvent with a small gas turbine (GT) and a low-pressure steam generator

This case specifically investigates the option of generating the regeneration and reclamation steam via heat recovery from the residual sensible heat contained in the exhaust flue gases generated by a dedicated gas turbine. This is the first option investigated in which the interfacing with the existing power plant is limited (no steam extraction), hence existing plant output is maintained and process risk and downtime are reduced. In this case, natural gas is the fuel used to ultimately deliver the regeneration thermal energy. However, rather than simply raising LP steam in a fired heater, the natural gas is fed in to a gas turbine to generate power before the exhaust heat is used to generate the LP steam needed for the PCC process.

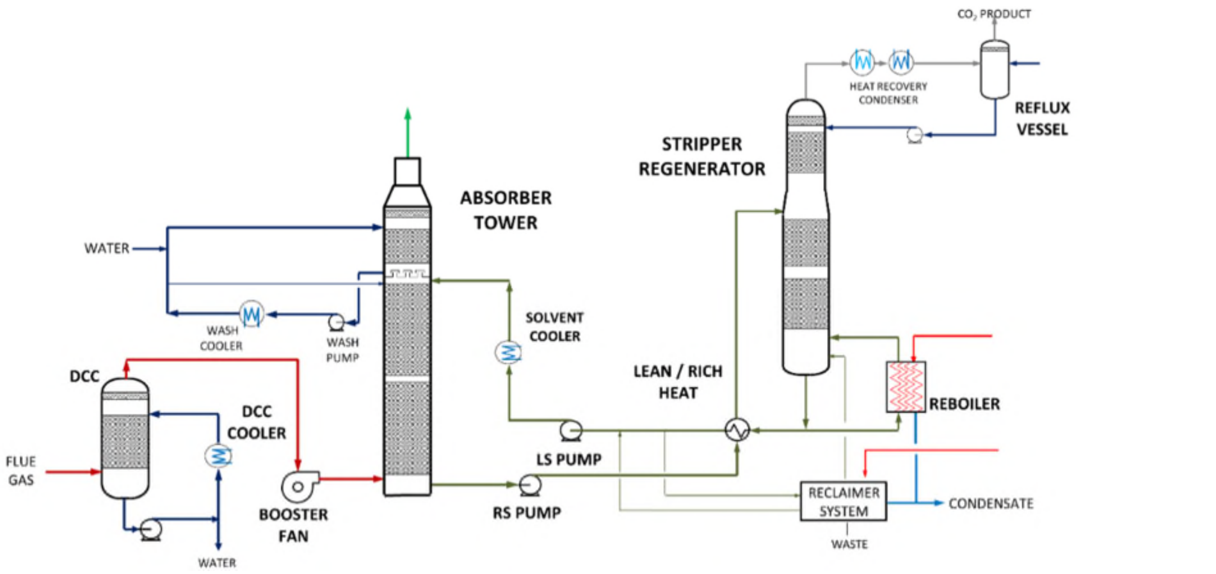


Figure 3. Post Combustion Capture Process for all Cases 1 and 4

1d. Commercial advanced solvent with a GT, triple-pressure heat recovery steam generator (HRSG), and a back pressure steam turbine

This case is similar to Case 1c except that the exhaust heat from the gas turbine is utilized to raise high-pressure steam using a triple-pressure HRSG, as shown in Figure 4. This case utilizes the temperature available from the GT exhaust more effectively as the stream generated can be used to produce power in a dedicated steam turbine before being passed to the PCC plant for solvent regeneration.

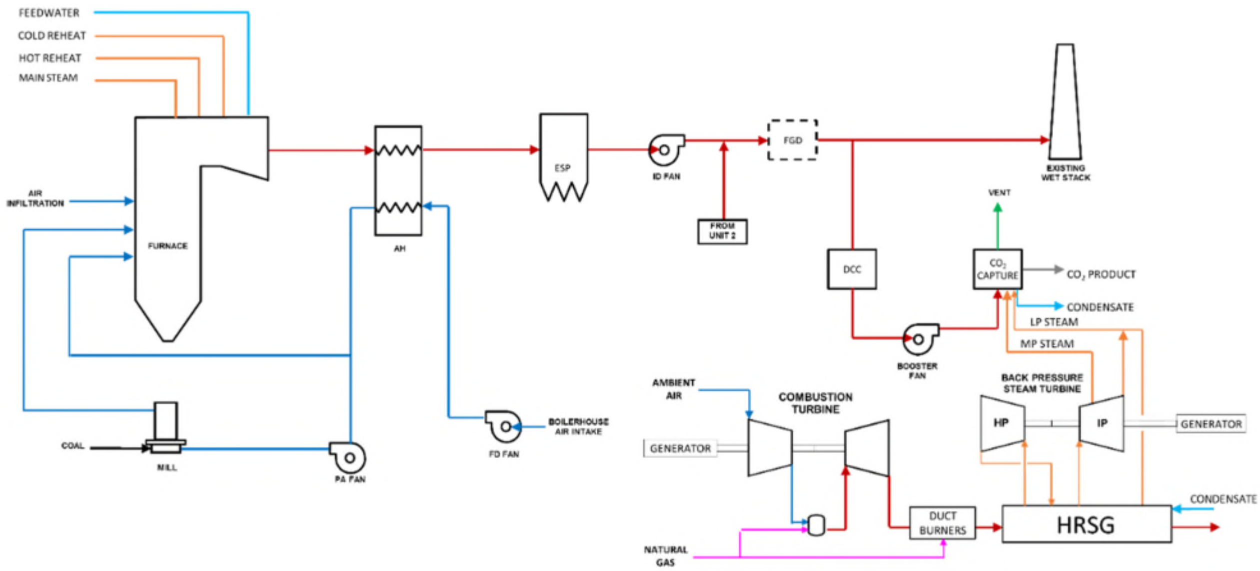


Figure 4. Boiler Island with Independent Reboiler Steam Source (Case 1d shown)

In comparison to Case 1c, a larger quantity of natural gas is fired to generate more heat for steam generation because a portion of that energy is converted to power before the stream is used for solvent regeneration. Subsequently the size of the gas turbine in this case will be larger than with Case 1c, with a corresponding increase in power output in addition to the additional power generated by the back pressure steam turbine.

1e. Commercial advanced solvent with a natural gas boiler and back pressure steam turbine

A lower capital cost variant of Case 1d was investigated in this case, in which the gas turbine was substituted for a dedicated gas-fired boiler which generated steam directly fed to the back pressure stream turbine prior to the exhausted LP steam being used for PCC regeneration.

2. Repowering of existing steam turbines with new a GT and HRSG

This case was identified as a repowering variation on the base case, in which a new GT/HRSG combination would be installed to feed steam to the existing steam turbine equipment. This differs from the base case in that it would have a reduced capital expenditure (no need to procure a new steam turbine, condenser, generator and associated equipment) but the resulting efficiency will be different due to the fact that the existing steam turbines would not be optimized for the steam conditions generated by HRSG units. Due to the additional power generated by the gas turbine, only one steam turbine is modified; the second unit is not required.

3a. Operating a new solid-oxide fuel cell (SOFC) in conjunction with the coal units

This case looks at adding an SOFC with carbon capture and integrating the excess heat with the existing coal-fired boiler. The SOFC unit operates at elevated temperatures, generating power directly from the electrochemical oxidation of the natural gas fuel. The off-gas from the SOFC anode is combusted with high-purity oxygen generated by an air separation unit (ASU), resulting in a wet, high-purity CO_2 stream that can be dried and compressed to export conditions. Excess heat generated by the SOFC stack is recovered by generating HP saturated steam which is passed to the existing boiler, superheated, and fed to the steam turbine, thus lowering the coal consumption of the boiler. Due to the additional power generated by the SOFC, only one coal boiler needs to be operated to achieve the required output in this case.

3b. Molten Carbonate Fuel Cell (MCFC) in conjunction with the coal units

The Combined Electric Power and Carbon Dioxide Separation (CEPACS) unit comprises an electrochemical membrane (ECM) unit which separates the CO_2 from the other components in the flue gas, leaving the FGD along with a CO_2 purification and compression step. The ECM unit is based on FuelCell Energy’s Molten Carbonate Fuel Cell (MCFC) technology. The CEPACS unit is installed downstream of the FGD system on Units 3 and 4 of the LGS, as shown in Figure 5. To meet the 420 kg/MWh emission intensity limit, a portion of the flue gas bypasses the CEPACS system and is fed to the existing stack. The remaining flue gas to be treated is fed to the cathode side of the ECM and the CO_2 migrates across the electrolyte in the fuel cell as carbonate ions, generating additional electricity. The CO_2-depleted flue gas exits the fuel cell, is cooled and vented.

Natural gas is mixed with excess steam, preheated and passed over a reforming catalyst which converts most of the mixture to CO_2 and H_2, together with a small quantity of CO. Unreacted methane and inert gases (N_2) are also present. The reformed natural gas is fed to the anode-side of the ECM and is oxidized by the carbonate ions generating CO_2 and water. The anode offgas, which also contains some unreacted natural gas, CO and H_2, is cooled, dried and compressed. The CO_2 is separated from the other “permanent” gases by simple liquefaction. The liquid CO_2 is pumped to discharge pressure and warmed to ambient temperature. The “permanent” gas stream is split; part is recycled to the inlet of the anode, and the remainder is used to preheat the inlet to the cathode in a catalytic oxidizer.

The condensate from the sea water condensers is polished and then combined and fed to the CO_2 purification unit in the CEPACS system for heat recovery. The warm condensate is split in to two equal streams, deaerated, and the reheat is completed via a series of boiler feedwater heaters which use casing purge steam and steam extracted from the turbine, and finally returned to the boiler.

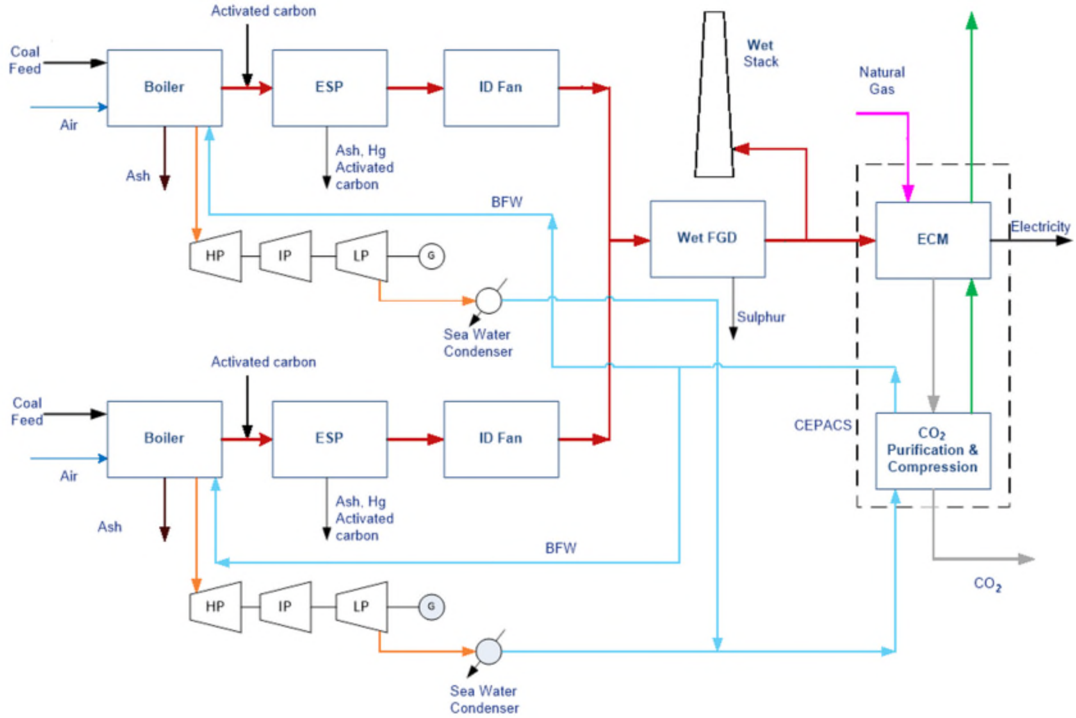


Figure 5. Boiler Island with CEPACS CCS unit (Case 3b shown)

4a. Expanded PCC approach with third coal-fired unit and full LP steam turbine bypass supplying steam to PCC

All other cases investigated the potential presented at LGS in which 4 boiler units are available and only 2 are utilized for the repowering cases. In this case, a third Lingan unit can be reassigned to generate some additional power whilst producing all of the LP steam needed to regenerate all of the solvent needed to ensure full compliance with the 420 kg/MWh emission intensity limit. The benefits of this are: 1) the remaining 2 steam turbine units are not impacted by the need for extraction steam, 2) no natural gas is needed, and 3) no additional capital costs are incurred for fired equipment and heat transfer surface.

4b. Expanded PCC approach with circulating fluidized bed (CFB) boiler and back pressure steam turbine

As with Case 4a, this case represents the coal-only case in which no additional boiler units are available to deliver the LP steam needed by the PCC regeneration. A CFB has therefore been specified as a heat source with high-pressure steam generation delivered to a dedicated back pressure steam turbine to feed the PCC power and regeneration requirements. This case will also be comparable with Case 1e as the only difference is the use of coal to generate the high-pressure steam rather than using a natural gas-fired boiler.

2.3. Basis of Design

Feedstock and Products

For all cases interfacing with the existing Lingan plant, the flue gas conditions are represented in Table 1. This flue gas is representative of Columbian coal used at the Lingan site. Carbon dioxide produced from the capture processes conformed with the attributes specified in Table 2, considered to be compatible with enhanced oil recovery application in addition to geologic storage.

Table 1. Lingan Flue Gas Properties

Item		Units	Flue Gas
Composition	Nitrogen	Mole %	71.0
	Oxygen	Mole %	5.0
	Carbon Dioxide	Mole %	12.0
	Water	Mole %	12.0
	Nitrogen Oxides	ppmv	170
	Sulphur Oxides	ppmv	10
	Hydrogen Chloride	ppmv	0.7
Total Flow		Nm^3/h	1,271,300
Temperature		°C	50
Pressure		bara	1.013

Table 2. Carbon Dioxide Specifications

Item		Units	Limit
Composition	Carbon Dioxide	Mole %	≥ 95
	Nitrogen	Mole %	≤ 4
	Water	Dew pt. °C	≤ -40
	Oxygen	ppmv	≤ 100
	Hydrogen Sulfide	ppmv	10
	Carbon Monoxide	Mole %	≤ 0.1
	Glycol	$m^3 / 10^6\ m^3$	≤ 0.174
Temperature		°C	≤ 50
Pressure		bara	153

Metrological

Plant design must be cognizant of the extreme seasonal weather changes at the Lingan location. The meteorological conditions for the site are shown in Table 3. Cooling water is available from the existing sea water system, operating on a once-through basis.

Table 3. Lingan Site Meteorological Data

Item		Units	
Mean (Performance)	Dry Bulb Temperature	°C	23
	Relative Humidity	%	70
Maximum (Design)	Extreme Temperature High	°C	40
	Extreme Temperature Low	°C	- 40
Site Elevation		m(ASL)	6
Cooling System - Sea water cooling			
Performance Case	Supply Temperature	°C	20
Maximum Temperature Rise		°C	10

Plant life and sparing philosophy

All new units in this study are designed on the basis of an operating life of 30 years; existing power block components would require life-extension work to deliver a comparative service life. Major components of the new equipment do not have spare plant installed, such as CO_2 compressor trains, booster fans, and gas turbine plant. Minor plant items (especially rotating equipment) has installed spares on a "plus one' basis, hence a 100% pump has 100% spare and two 50% pumps has one 50% spare installed.

3. Performance Assessment

The cases were investigated using a combination of AspenPlus™ modeling and performance calculations. Of the existing four LGS power blocks, in most cases only two of them were repowered, leaving the common utilities and infrastructure available for any additional equipment needed for repowering (such as cooling water, unit transformers, compressed air, etc.). All of the Case 1 variants were based on the application of post-combustion capture, with Cases 1a and 1b being the traditional arrangement in which solvent regeneration energy is drawn from the existing steam cycle (steam extraction from the IP/LP crossover). This results in a loss in output from the original 309 MWe, derating the overall plant output to between 218 and 236 MWe, depending on the solvent technology utilized. A capture quantity of around two thirds of the total CO_2 generated was needed in these cases to comply with the 420 kg/MWh federal limit. The other Case 1 variants were able to avoid plant derate by utilizing external heat sources for solvent regeneration using natural gas in different configurations, representing efficiency vs. capital cost tradeoffs. Because the quantity of CO_2 which can be emitted is based on the plant output, more-efficient options deliver both a benefit in output and a reduced capture plant size.

The quantity of natural gas fired in these cases is a function of the quantity of work produced by the system prior to the application of low-temperature thermal energy to the PCC reboilers and the overall CO_2 emission levels permitted by the increase in net output. Case 1c and 1d represent efficient use of the natural gas using a gas turbine, whereas Case 1e simply uses the natural gas as a heat source for a small back pressure steam turbine, exhausting all of the LP steam generated to the PCC reboilers. Table 4 shows that the gas turbine cases (Cases 1c & 1d) outperform the gas-fired boiler case (Case 1e). The combination of a gas turbine, HRSG, and a back pressure stream turbine (Case 1d) represents the best performance case due to the high net power output achieved (410 MWe) which enables the capture plant to be smaller than the other cases.

Table 4. Performance Results

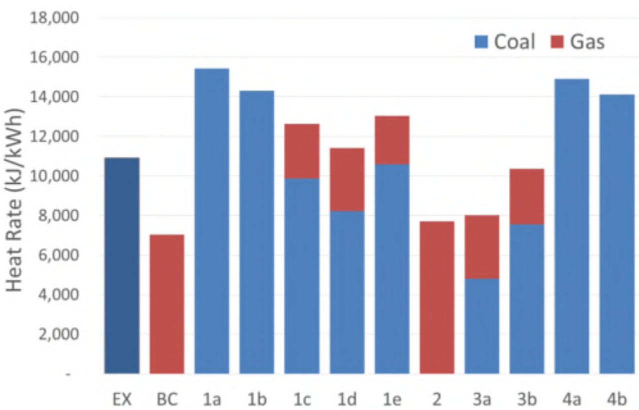
Key Physical Characteristics	Lingan	BC	1a	1b	1c	1d	1e	2	3a	3b	4a	4b
Net Output (MWe)	309	320	218	236	341	410	318	328	306	444	294	309
Coal Heat Rate (GJ/MWh)	10.9		15.4	14.3	9.9	8.2	10.6	-	4.8	7.6	14.9	14.1
Natural Gas Heat Rate (GJ/MWh)	-	7.0	-	-	2.7	3.2	2.4	7.7	3.2	2.8	-	-
CO_2 Produced (Mt/yr)	2.37	0.90	2.37	2.37	2.74	2.89	2.67	1.00	1.43	2.86	3.08	3.06
CO_2 Captured (Mt/yr)	-	-	1.58	1.53	1.55	1.47	1.56	-	0.39	1.39	2.03	1.98
CO_2 Emitted (Mt/yr)	2.37	0.90	0.78	0.84	1.19	1.41	1.11	1.00	1.04	1.46	1.05	1.09
CO_2 Captured (%)	0%	0%	67%	65%	57%	51%	58%	0%	27%	49%	66%	64%
CO_2 Avoided (Mt/yr)	0.00	0.00	0.89	0.97	1.43	1.74	1.33	1.51	1.31	1.95	1.21	1.28
Federal CO_2 Intensity (kg/MWh)	974	354	420	420	420	420	420	388	420	420	420	420

In Case 2, the existing steam turbine utilizes steam generated in a new HRSG. The balance of steam generated at the high-pressure (HP), intermediate-pressure (IP) and low-pressure (LP) turbines is substantially different from that of the coal-fired heat source as the HRSG relies on convective heating, whereas the boiler utilizes radiant heat in the firebox to raise a greater balance of HP steam. Consequently, the existing steam turbine operates in an off-design fashion in which the LP turbine is fully utilized but the high-pressure sections have lower throughput and hence lower output. Careful consideration is needed to ensure the thrust balance between turbine sections is maintained when operated in this way. The natural gas feed rate is 10% higher than the base case; however, this case avoids the capital expenditure of a new dedicated steam turbine.

Case 3a represents the addition of an SOFC to partially repower the existing steam turbine and produce additional power. The SOFC is configured to capture CO_2 from the anode offgas stream. PCC is not installed on the existing coal-fired power plant. Case 3b is similar in concept to Cases 1c, 1d and 1e, except the CEPACS PCC unit is more efficient at generating power than a co-gen unit and has lower parasitic losses than an amine system, resulting in the only PCC case with a lower overall plant heat rate than the original plant.

The final options considered, Cases 4a and 4b, represent repowering options in which no natural gas is available, which is effectually the case for LGS. Case 4a utilizes one of the 2 redundant coal units to facilitate steam production for the PCC reboilers. To reflect the scenario in which there are no redundant units available at a given site, Case 4b adds a dedicated coal boiler system for steam production, using a fluidized bed arrangement for maximum fuel flexibility. Because the only fuel available is coal, these cases have the highest CO_2 production rate and hence the highest capture ratio of all cases due to the higher carbon intensity of the fuel. As was the case with Case 2, re-tasking an existing steam turbine to operate at a reduced load leads to an efficiency penalty. In addition to this, the entire LP turbine is bypassed on this arrangement, requiring modifications to the turbine sealing systems.

The specific heat rate and CO_2 account for all cases is shown in Figure 6. Note that the federal CO_2 intensity is based on the CO_2 emissions and the net plant generation minus the power for CO_2 compression, which needs to be no greater than 420 kg/MWh on this basis. Clearly the existing Lingan units would have a non-compliant CO_2 intensity of 974 kg/MWh (EX in Figure 6) and both of the “natural gas-only cases” (base case CCGT replacement plant and Case 2 steam turbine repowering) require no carbon dioxide abatement. All other cases have had varying degrees of carbon capture applied to achieve the federal CO_2 limit, with Case 3a (SOFC) achieving the lowest capture rate, although it must be noted that this case only used a single boiler unit and thus fired half of the coal in comparison to the Case 1 variants.



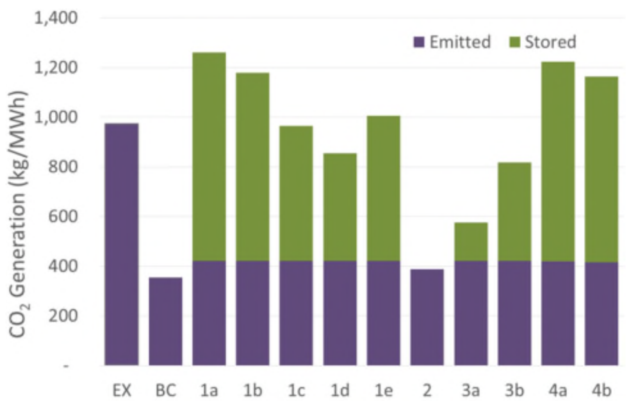


Figure 6. (a) Heat Rate and (b) CO_2 Account

4. Repowering Economic Analysis

The economic analysis assumed a plant in-service date of January 2020, based on the applicability of the pending CO_2 intensity limit to some existing coal-fired units in Canada. The forecast natural gas cost for Nova Scotia is expected to be \$10.00/GJ and is escalated at 2% per annum thereafter, with the coal cost taken as \$4.73/GJ. Because the existing plant would be considerably older than the repowering equipment, the existing power island components would require life-extension upgrades to ensure efficient and reliable performance when the repowered operation commences (limited to only the steam turbine in Cases 2 and 3).

In addition to life-extension costs, the future coal plants will require flue gas desulphurization (FGD) to meet the low SO_2 levels permitted to enter amine solvent-based capture systems. It is expected that in cases of partial capture, the entire flue gas would be processed by the FGD unit as this would represent the best available environmental option. The SOFC in Case 3 requires the natural gas to be desulfurized, which has been accounted for in the SOFC costs.

Table 5 shows the capital costs for the cases investigated with a breakdown for existing plant upgrades (life extension and FGD unit) and the new plant requirements (carbon capture, gas turbine, etc.) – the incremental cost is defined as the cost of all new plant with the costs of existing plant upgrades subtracted, as these are already-committed costs for future operations. Figure 7a presents the capital costs graphically to allow easy comparison, showing that cases that have no need to install FGD plant offer a significant advantage. The costs to install the new GT/HRSG equipment is lower than the incremental costs of all cases involving capture; as such, when natural gas fuel is readily available, the lowest investment costs are incurred by retiring the coal facilities.

Table 5. Capital Costs

$ million (CAD)	Lingan	BC	1a	1b	1c	1d	1e	2	3a	3b	4a	4b
Life Extension	75	0	75	75	75	75	75	38	38	75	94	75
FGD	220	0	220	220	220	220	220	0	99	220	286	220
Incremental Plant	0	573	460	417	644	718	517	405	1347	975	522	833
Total Cost	295	573	755	712	939	1013	812	443	1484	1270	901	1128
Incremental Cost	0	278	460	417	644	718	517	148	1222	975	650	833
Capex ($/kW)	956	1787	3457	3021	2753	2469	2555	1351	4951	2859	3217	3650

The final delivered cost of electricity from the plant depends on the operating costs as well as the CAPEX. The operating costs reflect the relative heat rates achieved by the different strategies as well as the fuel costs. The first year cost of electricity (COE) represents the break-even cost for any given case and is the price the power would need to be sold in the first year (escalated by inflation thereafter) to achieve a net present value (NPV) of zero. Table 6 and Figure 7b shows that the lowest COE is achieved with the gas-only cases, the base case and Case 2. Case 2 has a higher overall heat rate and so the additional gas costs throughout the life of the plant represent a higher overall COE than for the base case.

Of the amine PCC-enabled cases, Case 1d achieves the lowest first year cost of power. It must be noted that this is facilitated by the large impact of additional (and efficient) power generation using natural gas which not only supplies the reboiler thermal energy, but enables a smaller carbon capture rate (only 51%) to be realized as a result of the extra output. Case 1b represents the lowest COE for the coal-only cases, reflecting that the inefficiency of the steam extraction process (mainly the impact on the LP turbine) is less than that operating a third unit at a reduced load on the HP and IP sections. However, the difference between these cases is small at less than 7% of the COE.

Table 6. First Year Cost of Electricity and Capture Costs

		Lingan	BC	1a	1b	1c	1d	1e	2	3a	3b	4a	4b
First Year COE	$/MWh	93	109	171	158	153	141	151	115	157	135	167	165
Avoided Cost	$/t			151	124	113	89	110	38	119	76	143	137
Capture Cost	$/t			85	79	104	105	93	0	404	106	85	89

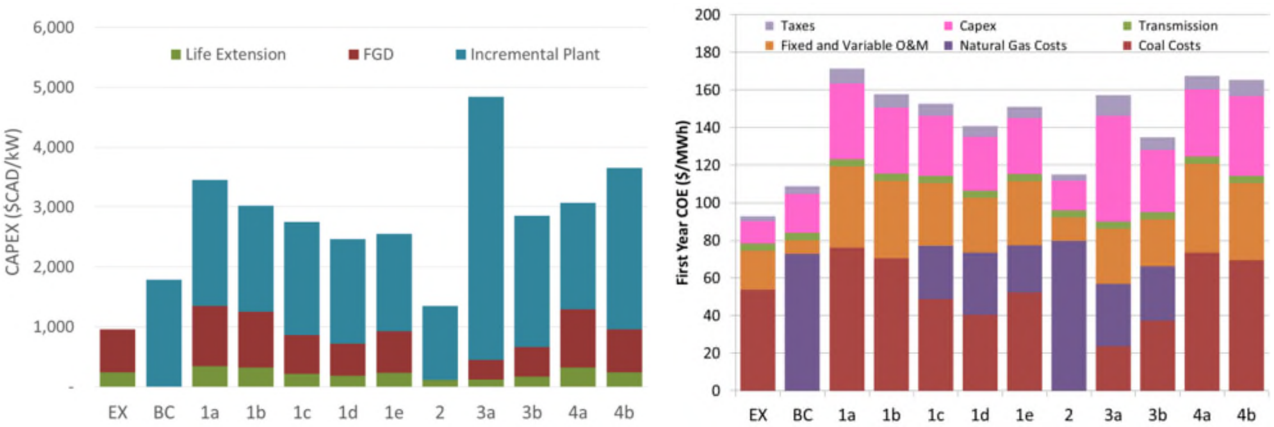


Figure 7. (a) Capex and (b) First Year COE

The SOFC system showed impressive heat rate values due to the high efficiency of the SOFC and near 100% carbon capture, which when combined with the single operating boiler resulted in a very low overall capture requirement of 27%. Despite this, Case 3a has one of the highest first year COE, driven mainly by the high capital costs of the incremental plant. The SOFC supplies roughly half the power in this case, and therefore the cost of power for the SOFC with CCS is roughly $222/MWh. Case 3b (MCFC) has a lower capital cost than Case 3a and reduced parasitic losses resulting in the lowest COE for a coal utilizing case.

The avoided cost is calculated as the difference between the first year cost of power for the lower-GHG-intensity case and the reference case (Lingan) divided by the difference between the GHG emission intensities for these cases.

$$AC(\$/t) = \frac{COE_{cap} - COE_{ref}}{E_{ref} - E_{cap}} \tag{1}$$

Where:

AC = Avoided Cost ($/tonne)
COE = First Year Cost of Electricity ($/MWh) for the case as indicated by the subscript
E = Emission rate of CO_2 (tonne/MWh) for the case as indicated by the subscript

Although the base case NGCC could be used as the reference case as it reflects what would likely be built, because the GHG emission intensity of the NGCC is less than all the other cases, using a NGCC as the reference case yields negative avoided costs. Hence the existing LGS unit performance was used for the reference case.

The cost of capture is calculated in a manner similar to the avoided cost except the COE difference is divided by the capture rate:

$$CC(\$/t) = \frac{COE_{cap} - COE_{ref}}{C_{cap}} \tag{2}$$

Where:

CC = Cost of Capture ($/tonne)
COE = First Year Cost of Electricity ($/MWh) for the case as indicated by the subscript
C = Specific CO_2 Capture Rate (tonnes/MWh) for the capture case

The capture cost benefits from an increased level of CO_2 production for any given case. Hence cases which leverage natural gas-fueled power production will have a higher cost of capture because lower quantities of CO_2 are captured relative to the total power produced. Subsequently, Case 1b has the lowest capture cost at $79/MWh and Case 3a has the highest capture cost because, although the first year cost of power is comparable to the other cases, significantly less CO_2 is required to be captured, driving the specific cost of capture up significantly. As a result, Case 3a has been omitted from Figure 8b for clarity. Although the cost of capture can prove to be a useful metric if CO_2 has a commodity value (such as for enhanced oil recovery [EOR] use), it is not necessarily a good metric for comparing the economics of the cases in which a federal government CO_2 intensity limit is applied.

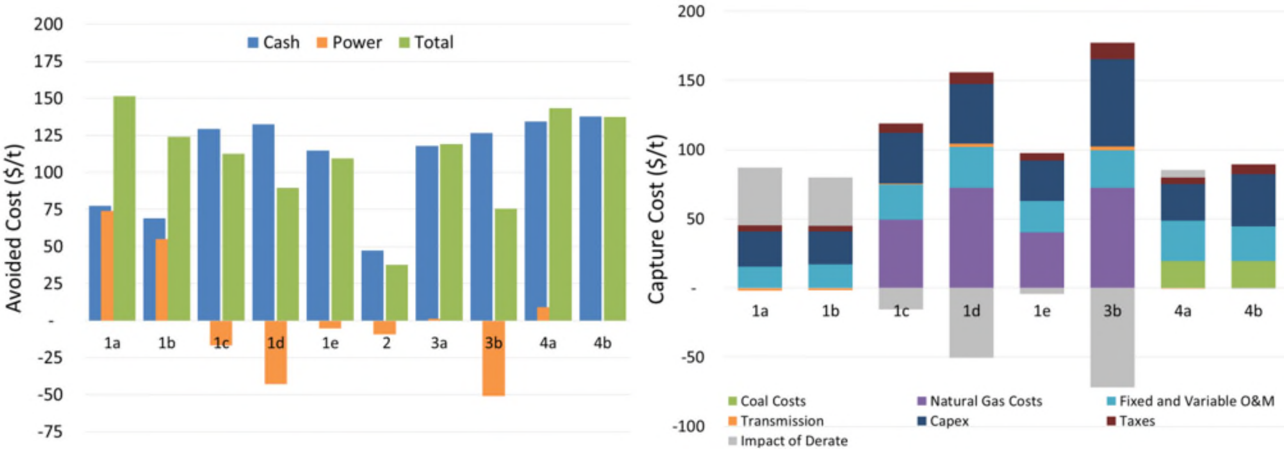


Figure 8. (a) Avoided and (b) Capture Cost Components

In Figure 8a, the term “cash” represents the incremental cash needed to perform the capture operation and “power” represents the cost to replace the power lost during capture (in which a negative value denotes additional power being generated). Case 2 (repowering existing steam turbines with new natural gas combined-cycle plant) without any additional CO_2 abatement, delivered both the lowest capital costs and cost of electricity. If the existing coal boiler plant remains operational, the lowest costs were achieved by installing an advanced solvent PCC unit with solvent regeneration thermal energy being delivered by an efficient, dedicated gas turbine with a triple-pressure HRSG (Case 1d). Where there is no existing infrastructure to deliver natural gas, the traditional methodology of extracting crossover steam from the unit proved to be the lowest-cost option.

4.1. Sensitivity Analysis

One of the main uncertainties for planning power plant infrastructure investment decisions is the cost of fuel, with natural gas being one of the most difficult to predict due to limited inventories, transportation issues and supply-demand interactions. Figure 9 shows the sensitivity of all investigated cases to the prevailing natural gas price, in comparison to the $10.00/GJ price used in the economic analysis.

The dotted lines represent cases influenced by natural gas price, as they rely on that fuel to either produce power directly (base case and Case 2) or utilize natural gas to energize the capture process (Cases 1c, 1d, 1e and 3). It is clear from this chart that lower natural gas prices would significantly benefit the PCC cases using gas as a heat source as the best ‘coal only’ case (Case 1b) only becomes competitive at a gas price of over $10/GJ.

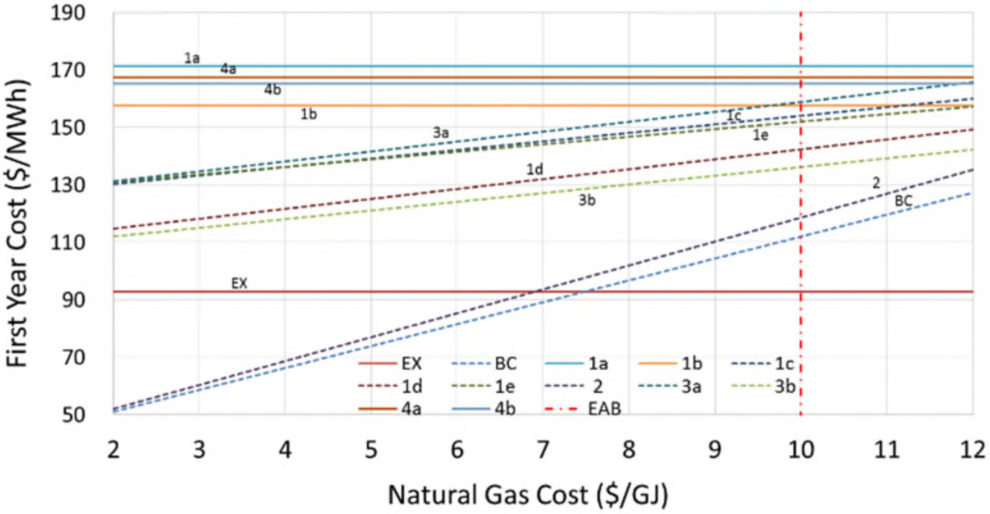
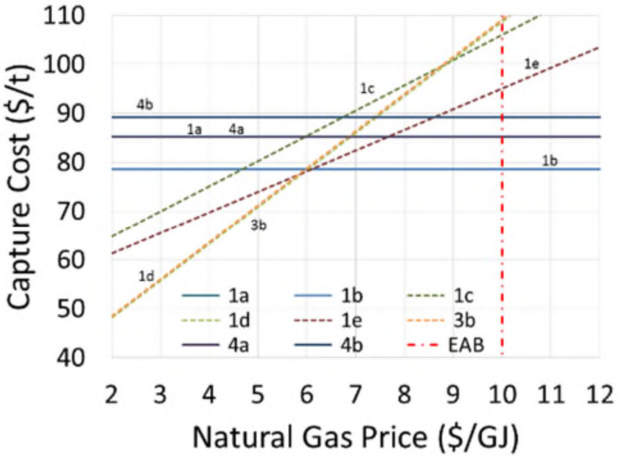


Figure 9. First Year Cost of Electricity vs Natural Gas Price

Figure 10a shows how the capture cost of CO_2 changes with the natural gas price. Again, the dashed lines show the cases which utilize natural gas, noting that the base case and Case 2 are absent as they required no capture. The natural gas price has a significant impact on the relative ranking of these cases, because a high price of gas and a relatively low capture rate result in a higher cost of capture, such as with cases 1d and 3b (MCFC). This cost decreases significantly as the gas price decreases. The capture cost for the non-gas-fired cases exceeds the capture costs for the gas-fired cases once the gas price drops below between $4-6/GJ. As before, Case 3a (SOFC) has not been included because its capture cost is so high due to the relatively low capture rate needed to comply with the 420 kg/MWh limit.

Figure 10b shows the avoided cost compared with a varying natural gas price. The lowest avoided cost is achieved in Case 2 for the gas price range investigated, due to this case being a reduced-carbon-intensity fuel substitution and not a capture case. The lowest PCC case avoided cost is consistently Case 1d, reflecting the higher degree of fuel substitution relative to the other cases (i.e., more gas turbine power generation). Of the coal fuel-only cases, Case 1b had the lowest avoided cost, which is higher than Cases 1c and 1e until the gas price reaches approximately $12/GJ. Again, due to the relatively low capture and high captial costs, Case 3a generally has a higher avoided cost until the natural gas price drops below $10/GJ, at which it becomes better than all coal-only cases.



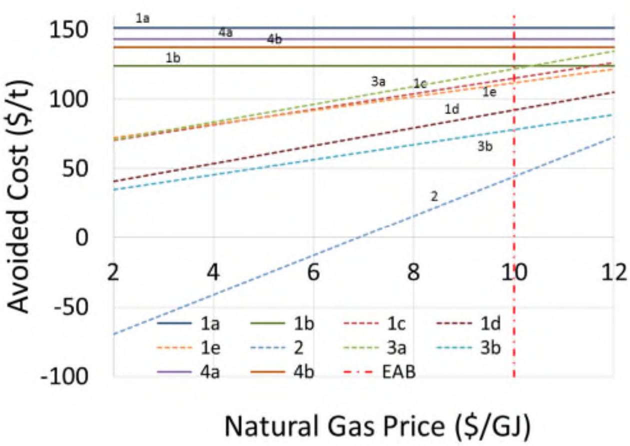


Figure 10. Natural Gas Price vs. (a) Capture Cost and (b) Avoided Cost

Although natural gas has more potential for uncertiantly in future delivery prices coal, too, can also face price uncertainty due to changes in global demand and the costs associated with extraction and transportation. Figure 11 shows how the first year cost of electricity changes with varying coal costs and a fixed natural gas cost. The 2020 delivered coal cost is assumed to be \$4.93/GJ. In Figure 11, because coal cost is the variable, all cases which use coal as a fuel in whole or in part are shown with dashed lines. It is clear that no case has a lower first year cost of electricity than the natural gas-fired cases.

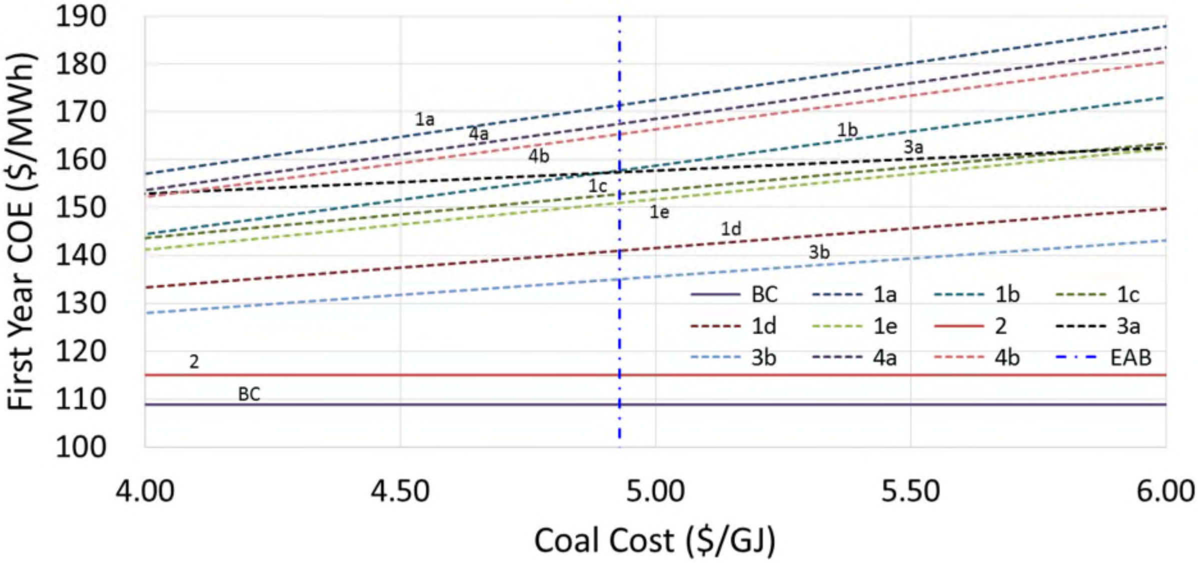


Figure 11. First Year COE Compared to Changes in Coal Cost

The change in first year cost of electricity when the capital cost varies is shown in Figure 12. Case 3 shows the highest rate of change in first year cost of electricity due to the relatively high capital cost component compared to other cases. With the minor exception of Case 3a, the relative ranking of all other cases does not change as capital cost increases or decreases.

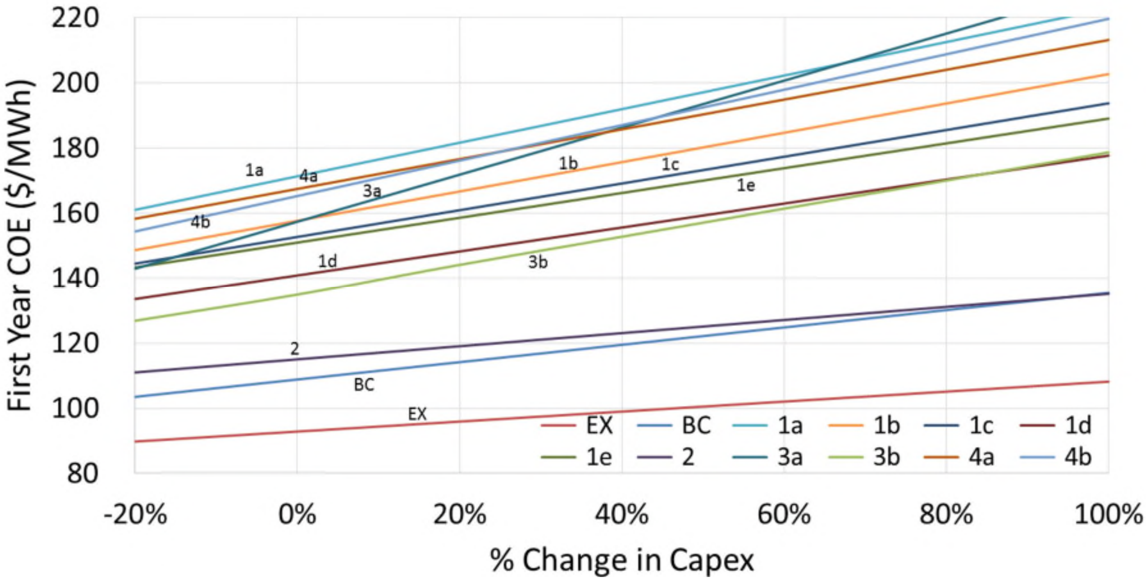


Figure 12. First Year COE Compared to Changes in Capital Cost

Figure 13 shows two graphs detailing the impact of changes in capital cost on the capture and avoided costs. As before, Case 3a has been excluded from the capture cost chart due to the high cost of capture resulting from low required capture quantity. As with the COE assessment, the relative ranking of the capture and avoided costs of all cases does not change as the capital cost changes with the specific exception for the fuel cell cases 3a and 3b due to the relatively high capital cost component in the overall cost profile.

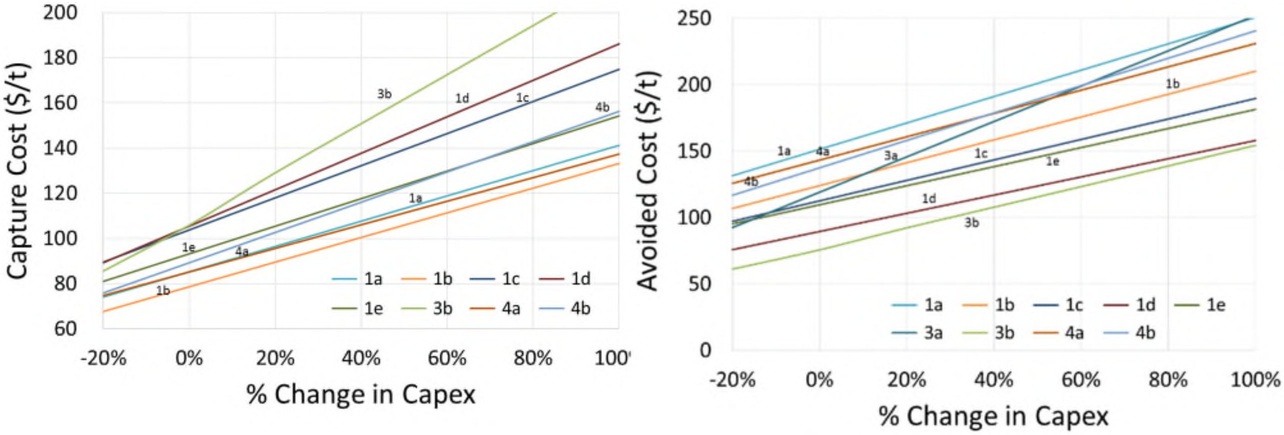


Figure 13. (a) Capture Cost and (b) Avoided Cost vs. Changes in Capital Cost

5. Conclusions

In this investigation, the overall lowest first year cost of electriclty was achieved by the NGCC base case with the repowering Case 2 just slightly higher. It is suspected that with some efficiency optimizations of the existing steam turbine and capital cost improvements, Case 2 could provide better economics than a new NGCC base case. None of the PCC cases were economically attractive relative to the natural gas-fired cases at $10.00/GJ cost of gas. Case 1d with an alternate steam supply, which produces a significant amount of additional natural gas fired power, was the lowest-cost amine based PCC case.

Despite Case 3a (SOFC) having the lowest heat rate of any case utilizing coal, the high captial costs resulted in a higher first year cost than the PCC cases. Although Case 3b (MCFC) has a lower expected first year cost of power than any of the amine based PCC cases, it is expected to have a higher first year COE than the repowering Case 2. The final two cases that utilize additional coal to produce the required PCC steam (cases 4a and 4b), had a first year COE slightly higher than that of Case 1b (PCC with steam extraction). As Figure 9 shows, at low natural gas prices, clearly Case 2 and the NGCC case reflect the lowest first year cost of power. However, if gas prices stay high or even increase in Nova Scotia, the PCC cases could become competitive.

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