

# Comprehensive Environmental Impact Assessment of a Combined Petroleum Coke and Natural Gas to Fischer-Tropsch Diesel Process

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*Date Submitted:* 2020-03-13

*Keywords:* GHG Emissions, Petroleum Coke, Natural Gas, Life Cycle Analysis, Carbon Dioxide Capture

## **Abstract:**

In this study, a well-to-wheels life cycle assessment was conducted to determine the environmental impacts from disposing of petroleum coke by converting it into liquid fuel. Specifically, three processes for converting petroleum coke and natural gas to Fischer Tropsch diesel were investigated, both with and without carbon capture and sequestration (CCS). Impact categories were calculated using the EPA's TRACI 2.1 US-Canada 2008 midpoint method in SimaPro software. In addition, the impact of grid emissions on the overall process was assessed using two representative Canadian locations with high (Alberta) and low (Ontario) grid emissions. The results of each impact category were compared among the designs and against conventional petroleum and oil-sands derived diesel. Key findings showed that the proposed designs when operated using CCS in the low-emissions-grid location had lower life cycle GHG emissions than conventional petroleum and oil-sands derived diesel. Nevertheless, the various tradeoffs between processes indicated that there was no clearly superior design among the candidates. However, the design which uses a natural gas reformer that is integrated directly into the radiant syngas cooler of a petcoke gasification unit has the lowest cost of CO<sub>2</sub> avoided, and so is likely the best choice for environmental purposes.

*Record Type:* Preprint

*Submitted To:* LAPSE (Living Archive for Process Systems Engineering)

*Citation (overall record, always the latest version):*

LAPSE:2020.0305

*Citation (this specific file, latest version):*

LAPSE:2020.0305-1

*Citation (this specific file, this version):*

LAPSE:2020.0305-1v1

*DOI of Published Version:* <https://doi.org/10.1016/j.ijggc.2020.103012>

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1 Comprehensive Environmental Impact  
2 Assessment of a Combined Petroleum  
3 Coke and Natural Gas to Fischer-Tropsch  
4 Diesel Process

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9 **ABSTRACT**

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25 for environmental purposes.

26 *Keywords: Petcoke, Natural gas, CO<sub>2</sub> capture, Life cycle assessment, GHG,*

## 27 **1.0 Introduction**

28 Petcoke is the unwanted solid waste that is produced when petroleum residues or oil sand  
29 bitumen is upgraded to lighter fractions. Despite the high market value of these liquids, petcoke is  
30 generally of limited use. For example, unprocessed petcoke from a coker unit is usually high in  
31 sulfur and considered low grade (fuel grade); as such, it is most commonly used as an inexpensive  
32 fuel source for boilers, cement kilns, etc. However, government restrictions on petcoke combustion  
33 have prohibited its use as fuel, at least in parts of North America [1]. Some petcoke can also be  
34 further processed (calcination operation) to produce high-grade (anode grade) petcoke, which is  
35 used in the steel and aluminum industries. The remaining produced petcoke (generally unprocessed  
36 petcoke) is stockpiled indefinitely, which poses a number of problems. Besides occupying valuable  
37 land at storage locations, this stockpiled coke is responsible for a variety of environmental impacts,  
38 such as air and water pollution, as well as having potentially detrimental effects on the respiratory  
39 health of nearby populations [2]. These concerns highlight the need for the development of a  
40 benign petcoke “end of life” strategy.

41 Wabash River Energy Ltd.’s 262 MWe power plant offers one potential solution for  
42 disposing of low-grade petcoke, as its GE 7FA turbine is driven by syngas generated by petcoke  
43 gasification [3]. Additionally, Wabash River Energy has also shown that petcoke can be used in a  
44 coal gasifier without any operational issues. The Tampa Electric Polk Power Station provides  
45 another possible solution for petcoke disposal, as its integrated gasification combined cycle  
46 (IGCC) utilizes a combination of petcoke and coal to produce electricity [4]. Besides power  
47 generation, petcoke has been used for fuel and chemical production. For instance, the Coffeyville  
48 syngas plant uses petcoke from the Coffeyville refinery as a zero-value waste fuel to produce 1,300  
49 tons of ammonia per day [5]. This clearly illustrates how petcoke stockpiles can be used to produce  
50 value-added products. Similarly, polygeneration studies conducted by the US Department of  
51 Energy’s National Energy Technology Laboratory (NETL) have found that the conversion of  
52 petcoke to hydrogen, fuel gas, industrial-grade steam, and Fischer-Tropsch (FT) liquid fuels is an  
53 economically attractive option when petcoke is zero cost [6]. A different study examined the

54 optimization of petcoke-natural gas polygeneration for the production of olefins, methanol,  
55 dimethyl ether (DME), and FT liquids [7]. The results of this study showed that petcoke-natural  
56 gas polygeneration is not economical when petcoke is used above a certain ratio (petcoke/natural  
57 gas). Petcoke has also been proposed for use in power-to-gas technology in order to produce a  
58 range of products, including fuels and chemicals [8]. That study was the first to employ a mixed-  
59 inter linear programming to assess the economics of using electrolysis and surplus grid electricity  
60 for petcoke disposal in a polygeneration system. Recently, we presented six strategies for  
61 converting petcoke to FT diesel and gasoline that focused on design efficiency, NPV, and GHG  
62 emissions [9]. Our results indicated that this approach is economically promising when petcoke  
63 gasification is tightly integrated with a natural gas reforming process. Although the conversion of  
64 petcoke to liquids has tremendous technical and economic potentials, detailed studies of this  
65 process' environmental impacts do not exist. Therefore, a life cycle assessment—which is a  
66 systematic approach to evaluating the environmental impacts of a particular process to ascertain  
67 its overall effects on the eco-system—was conducted in this work.

68 Alternatives liquid fuels, such as those made from coal, gas, and biomass, can potentially  
69 have lower life cycle impacts and/or be competitive with conventional fuels in terms of actual cost  
70 or cost of CO<sub>2</sub> avoided. In many cases, though, alternative fuels have none of these advantages.  
71 For example, Jaramillo et al. [10] conducted a life cycle assessment that compared GHG emissions  
72 from vehicles operated with coal-to-liquid (CTL) fuels against coal-based electricity powered  
73 plug-in hybrid electric vehicles (PHEV) and coal-based hydrogen-fuel-cell vehicles (FCV). Their  
74 results showed that PHEVs produced less GHG emissions than the CTL vehicle and FCVs, and  
75 that the CTL vehicle and FCVs also produced more GHG emissions than petroleum-powered  
76 vehicles. Similarly, the NETL conducted a cradle-to-grave (CTG) life cycle assessment comparing  
77 the relative GHG emissions of FT diesel (FTD) made from Illinois #6 coal and petroleum-based  
78 diesel for sport utility vehicles (SUV) [11]. Their results showed that the coal-derived diesel had  
79 a GHG life cycle of 583.5 gCO<sub>2</sub>-eq/km, while the Wyoming sweet crude oil had a GHG life cycle  
80 of 290.8 gCO<sub>2</sub>-eq/km. For the gas-to-liquid (GTL) process, Forman et al. [12] used a substitution  
81 allocation method to perform a well-to-wheels (WTW) GHG life cycle assessment with the results  
82 of their assessment showing a GHG emissions of 292.9 gCO<sub>2</sub>-eq/km using a vehicle fuel economy  
83 of 8.6 litres per 100 km. Biomass-to-liquid (BTL) fuel production has also received considerable  
84 research attention due to its so-called “carbon neutrality” and reduced environmental impact. For

85 example, Kreutz et al. [13] performed a BTL LCA and found that, when the gasifier char carbon  
86 is assumed to be sequestered, BTL has a negative GHG emissions life cycle, even without CO<sub>2</sub>  
87 capture and sequestration.

88         Although these examples demonstrate that other alternative fuel pathways are promising  
89 from an environmental standpoint, the environmental aspects of petcoke-to-liquids are yet to be  
90 explored. Therefore, this study aims to examine the environmental impacts of a petcoke-to-liquids  
91 process known as the petcoke-derived-diesel (PDD) process. To this end, three configurations of  
92 this process will be considered, both with and without CCS: petcoke standalone gasification  
93 (PSG); petcoke gasification and external natural gas reforming (PG-ENGR); and petcoke  
94 gasification integrated with natural gas steam reforming (PG-INGR). Thus, a total of 6  
95 configurations were explored. Our prior work on these configurations [9] consisted of techno-  
96 economic analyses that used Aspen Plus v10 process-simulation software to compute process  
97 stream flows, energy consumption and production, equipment sizes and costs, and profitability. In  
98 addition, a WTW LCA of the PSG configurations was further computed in a second work [14]. In  
99 contrast, the present work’s primary contribution will be a WTW LCA of the PG-ENGR and PG-  
100 INGR configurations, which differ significantly from PSG due to their synergistic integration of  
101 natural gas as a raw material.

102

## 103 **2.0 Life cycle process methodology and assumptions**

### 104 2.1 Goal, scope, and boundaries

105         The goal of this study was to assess, quantify, and compare the environmental effects of  
106 six PDD process configurations—PSG, PG-ENGR, and PG-INGR—both with and without CSS.

107         The scope of this analysis comprised the WTW material and energy inputs and outputs,  
108 along with their emissions over the entire life cycle of each PDD process. The system boundaries  
109 considered for each configuration will include the well-to-plant exit gate (WTG), PDD  
110 transportation and distribution (WTT), and the subsequent use of PDD in a compression-ignition  
111 direct-inject (CIDI) vehicle (WTW), thus indicating the petcoke’s “end of life.” Figs. 1-3 depict  
112 this process for each of the analyzed configurations. For reference, the proposed designs were  
113 compared to conventional petroleum and oil-sands derived diesel. To this end, an energy allocation

114 method was used to determine emissions allocation for the gasoline and diesel produced in our  
 115 proposed designs. In order to further facilitate comparison, the inventories of the petcoke,  
 116 conventional petroleum, and oil sands diesel processes were normalized to 1 km distance driven  
 117 in a standard passenger car.

## 118 2.2 Impact assessment calculation

119 The life cycle impact assessment (LCIA) categories were calculated using the TRACI 2.1  
 120 v1.04 midpoint method in the life cycle flow-sheeting software, SimaPro v 9.0. The TRACI (Tool  
 121 for Reduction and Assessment of Chemicals and other environmental Impacts) method is a US  
 122 Environmental Protection Agency (EPA) LCA methodology that provides the characterization  
 123 factors used for LCIA and quantifies the impacts of the process inputs and their corresponding  
 124 emissions on a specific impact category in an equivalent unit [15]. Table 1 shows the midpoint  
 125 impact categories that were considered in this study, along with their corresponding extent or area  
 126 of impact. Unlike our previous work [14], the global warming potential (GWP) computed in this  
 127 study followed the Intergovernmental Panel on Climate Change’s (IPCC) 100-year metric  
 128 characterization factor updates for methane (CH<sub>4</sub>) and dinitrogen monoxide (N<sub>2</sub>O), which were 30  
 129 and 265, respectively. Thus, we recomputed the impact assessments of the PSG design presented  
 130 in our prior work [14] using these updated factors.

131 Table 1: Midpoint impact categories considered in this study.

Impact category	Abbreviation	Units	Level of impact
Ozone depletion potential	ODP	kg CFC-11eq	Global
Global warming potential	GWP	kg CO <sub>2</sub> eq	Global
Smog formation	SF	kg O <sub>3</sub> eq	Regional
Acidification potential	AP	kg SO <sub>2</sub> eq	Regional or National
Eutrophication potential	EP	kg N eq	Regional or National
Carcinogenics potential	CP	CTUh	National
Non-carcinogenic potential	NCP	CTUh	National
Respiratory effects	RE	kg PM2.5 eq	Regional or National
Ecotoxicity potential	ETP	CTUe	National
Fossil fuel depletion	FFD	MJ surplus	Global

132

## 133 2.2 Assumptions

134 The characteristics of the consumables used in this study are shown in Table 2.

135

136 Table 2: Assumed composition of consumable materials.

<b>Delayed coke [16]</b>			
HHV (MJ/kg)	34.7		
Ultimate analysis (wt. % dry)			
C	84.9	Cl	0
H	3.9	Ash	3.1
N	1.3	O (diff)	0.8
S	6		
Proximate analysis (wt. %)			
Moisture	1.8	Fixed carbon	83.3
Volatile matter	11.9	Ash	3
<b>Natural gas [17]</b>			
HHV (MJ/kg)	52.97		
Components (% mole)			
CH <sub>4</sub>	93.9	CO <sub>2</sub>	1.0
C <sub>2</sub> H <sub>6</sub>	3.2	C <sub>4</sub> H <sub>10</sub>	0.4
N <sub>2</sub>	0.8	C <sub>3</sub> H <sub>8</sub>	0.7

137

138 In addition, the following assumptions were made:

- 139
- 140 • The petcoke used in this study is delayed coke produced as an unintentional and undesired  
141 waste product from oilsands upgrading by Suncor Energy Inc. in Athabasca, Alberta. Since  
142 the petcoke is classified as waste, there are no indirect emissions associated with its  
143 production, as all emissions associated with refinery upgrading are instead associated with  
144 the saleable refinery products [18]. Therefore, all emissions attributed to petcoke in this  
145 study are direct emissions from the considered PDD processes and indirect emissions not  
146 associated with petcoke (such as natural gas procurement); the emissions calculation for  
147 each process begins at the petcoke stockpile, and includes transportation and handling for  
conversion purposes, as well as direct process emissions.
  - 148 • The petcoke and/or natural gas conversion facility locations used in this work were  
149 considered to be constructed in a “brown field.” One facility was within close proximity to  
150 the petcoke stockpile in Athabasca, Alberta, while the other was located near existing

151 refineries in Sarnia, Ontario. Hence, changes in direct and indirect land use were not  
152 considered in this analysis, as there was no additional land occupation associated with the  
153 brown field assumption. However, transportation-related emissions differed depending on  
154 the location scenario.

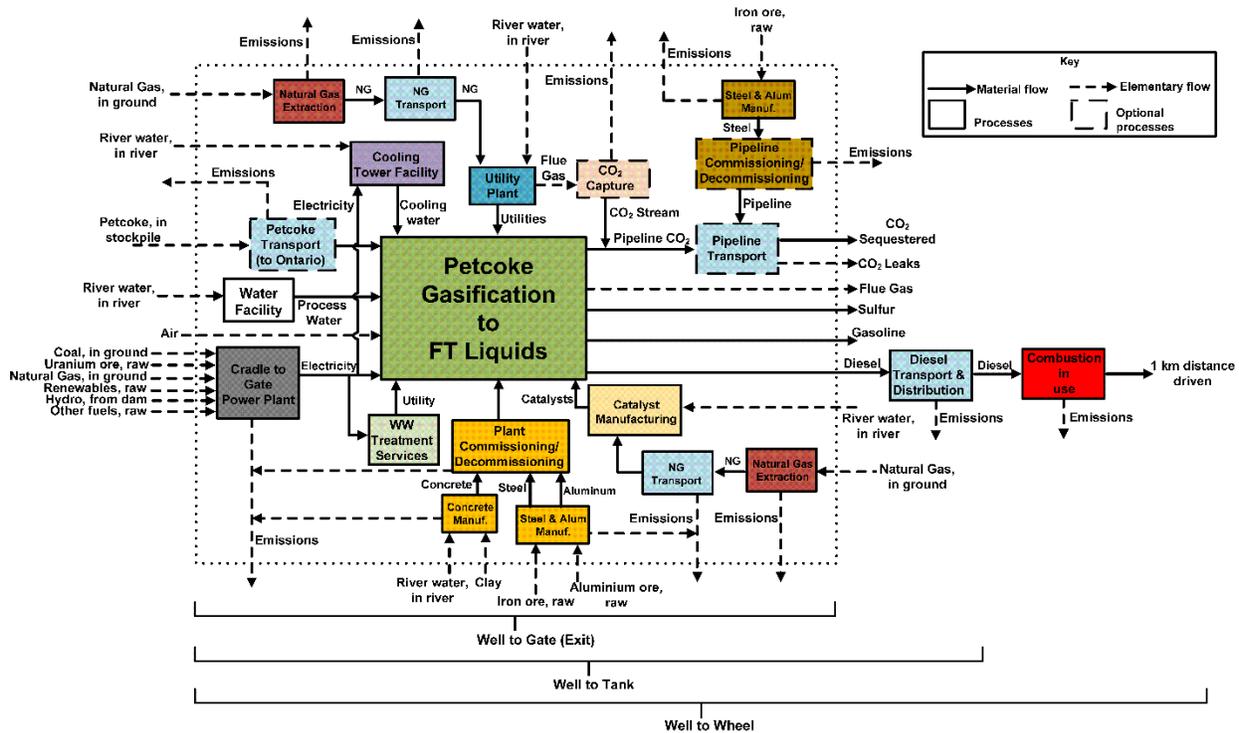
- 155 • Emissions from gasifier slag disposal were not considered because this material can also  
156 be used as concrete for road construction [19].
- 157 • The fugitive emissions of captured CO<sub>2</sub> during pipeline transportation were assumed to be  
158 1% of the transported CO<sub>2</sub> on a mass basis [20].
- 159 • The vehicle fuel efficiency and combustion emissions used in this study were based on the  
160 GREET model [21].

### 161 **3.0 Process description**

#### 162 **3.1 Petcoke standalone gasification design (PSG)**

163 Instead of stockpiling, petcoke is ground and mixed with water at ratio of 44 wt%:56 wt%  
164 (H<sub>2</sub>O: petcoke) to form a slurry. Syngas is then produced by feeding the slurry into the petcoke E-  
165 gas gasifier, which uses 99.5% pure oxygen delivered from an air separation unit located within  
166 the analysis boundaries. The overall gasification reaction—namely, pyrolysis, volatile  
167 combustion, char gasification, and sulfur reaction—was considered when modeling the process  
168 [9]. The petcoke E-gas gasifier was designed to operate at 1426 °C and 56 bar. Due to the gasifier’s  
169 high operating temperature, boiler feed water (BFW) is usually used to provide the cooling duty  
170 required by the hot syngas in a radiant syngas cooler (RSC), which in turn produces high-pressure  
171 steam (HPS) [22]. The use of BFW as a syngas coolant distinguishes this design configuration and  
172 that of PG-ENGR from the PG-INGR configuration. The model assumed carbon conversion in the  
173 gasifier to be 99% [3], with unconverted carbon and trace metals such as nickel and vanadium  
174 exiting the gasifier as slag [23]. The syngas is cleaned, reformed to raise the H<sub>2</sub>:CO ratio, and sent  
175 to the acid-gas removal unit to remove H<sub>2</sub>S (which is converted to sulfur via Claus process) and  
176 capture CO<sub>2</sub> (which is compressed and sequestered) before being catalytically reformed to produce  
177 FT fuels. While 90% of the unconverted syngas was recycled, the remaining portion was used for  
178 steam generation (boiler flue gas flared to the environment). This description summarizes the  
179 subprocess, known as “Petcoke Gasification to FT Liquids,” illustrated in Fig. 1. The mass and  
180 energy flows (life cycle inventories) were taken directly from Okeke et al. [9] which can be found

181 in the supplementary documents. In addition to the flue gas, fugitive emissions (especially CO<sub>2</sub>  
 182 emissions) in wastewater treatment were also considered. Fig. 1 also provides a detailed account  
 183 of all indirect material and energy inputs into the PPD plant, along with their associated emissions.  
 184



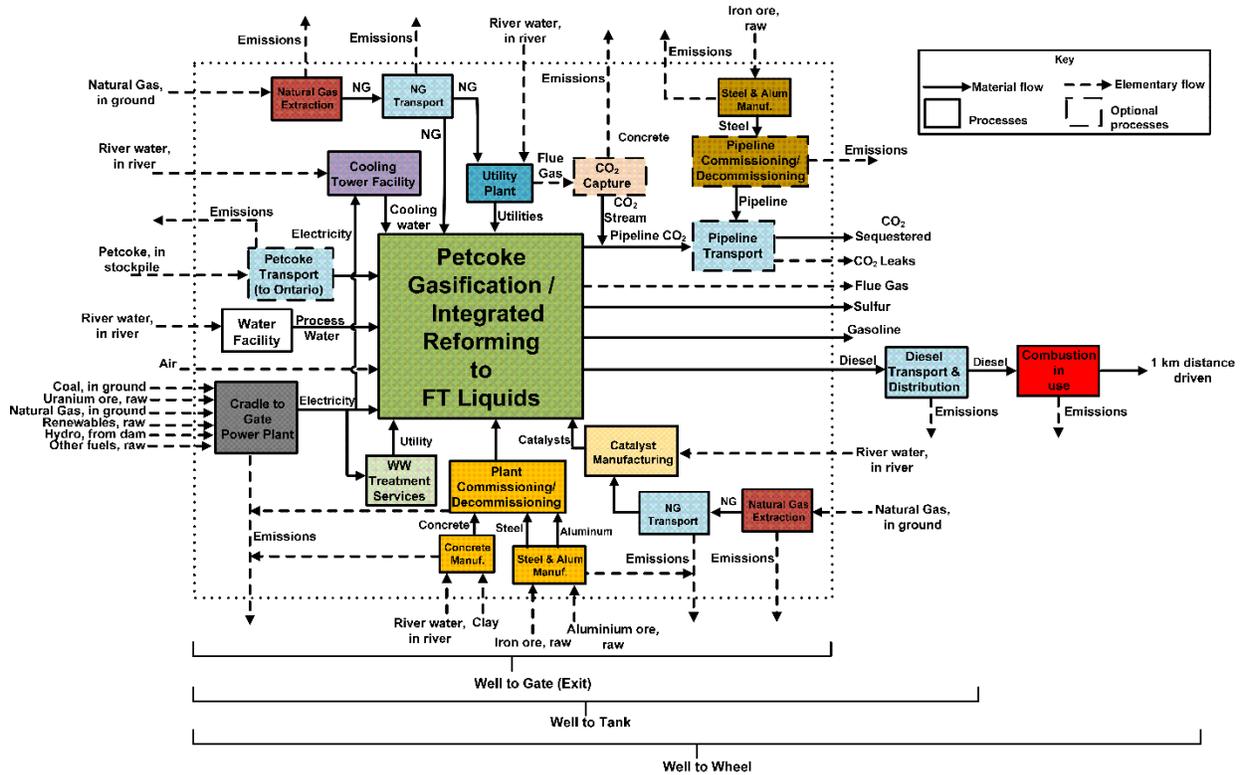
185  
 186 **Figure 1: System boundary of the petcoke standalone gasification design.**  
 187

188 **3.2 Petcoke gasification integrated with natural gas reforming (PG-INGR)**

189 This design configuration combines the use of petcoke and natural gas as feed for the  
 190 production of FT diesel. As with the PSG configuration, this process utilizes petcoke gasification;  
 191 however, unlike the PSG configuration, the PG-INGR configuration uses natural gas to cool the  
 192 hot gasifier syngas. In this design, pre-reformed natural gas and steam are sent through the gasifier  
 193 RSC tubes packed with steam methane reforming (SMR) catalysts. The hot petcoke-derived  
 194 syngas drives the endothermic steam-reforming process, which also cools the syngas [9]. The  
 195 syngas produced by this design is a blend of the petcoke gasifier syngas and the reformed natural  
 196 gas derived syngas, and it is used for liquid fuel production, much like the syngas produced by the

197 PSG design. This description summarizes the subprocess, known as “Petcoke Gasification  
 198 Integrated Reforming to FT Liquids,” shown within the system boundary of Fig. 2.

199



200

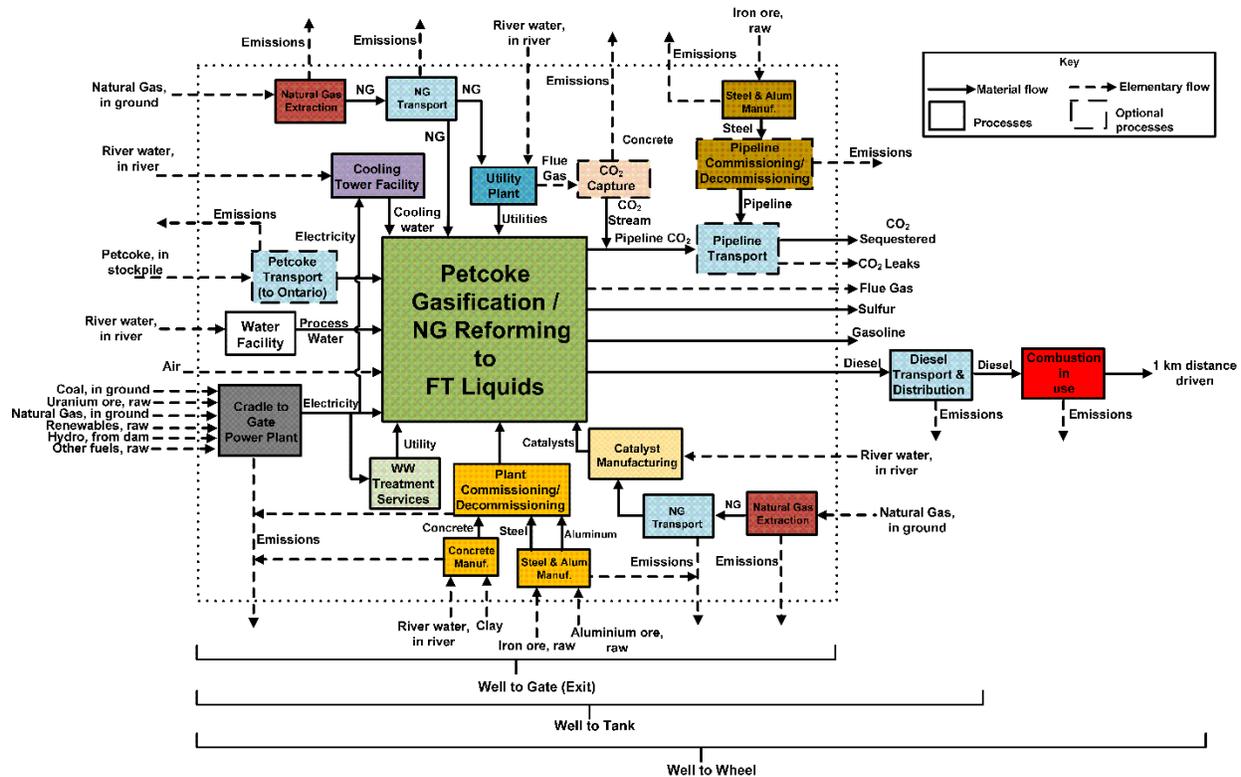
201 **Figure 2: System boundary of the petcoke gasification integrated with natural gas**  
 202 **reforming.**

203

204 **3.3 Petcoke gasification and external natural gas reforming (PG-ENGR)**

205 Although similar to both the PSG and PG-INGR designs, the PG-ENGR design is distinct  
 206 in its configuration. As with the PSG configuration, the PG-ENGR configuration utilizes BFW to  
 207 cool the syngas produced by hot petcoke gasification in an RSC. In addition, the PG-ENGR  
 208 configuration also combines petcoke gasification and natural gas reforming to produce liquid fuels.  
 209 This subprocess, known as “Petcoke Gasification / NG Reforming to FT Liquids,” is depicted in  
 210 Fig. 3. However, unlike PG-INGR, the PG-ENGR configuration uses a standalone auto-thermal  
 211 reformer to convert natural gas to syngas with a high H<sub>2</sub>:CO ratio. The rationale for the PG-ENGR  
 212 design is to effectively compare its performance with that of PG-INGR configuration since both

213 designs also use natural gas as feedstock, unlike the PSG design which uses only petcoke. The  
 214 system boundary for the PG-ENGR design is shown in Fig. 3.



215  
 216 **Figure 3: System boundary of the petcoke gasification and external natural gas reforming.**

217  
 218 **3.4 Other sub-processes**

219 **3.4.1 Plant construction**

220 The materials used to construct the plant and energy inputs and emissions for the PDD  
 221 system were both considered in this study. Given the similarities between the PDD and CTL  
 222 processes, the material, energy inputs, and the emissions associated with the construction and  
 223 decommissioning of the PDD process (all scenarios) were all estimated using data from an NETL  
 224 study of a CTL plant [24].

225 **3.4.2 Petcoke transport**

226 Due to the vast differences in electricity grid carbon intensity across possible plant  
 227 locations, we considered a scenario that involves the transportation of petcoke from Athbasca,  
 228 Alberta to Suncor Energy Inc.’s yard, which is located in Sarnia, Ontario. This approach was

229 selected because it was expected to be helpful in evaluating the extent to which electricity grid  
230 emissions impact the PDD process. The Ontario location was chosen because it was considered to  
231 be representative of a site with low electricity grid emissions. Plants are typically designed to  
232 enable coke to be deposited from the cokers into the open hoppers of the rail cars with maximum  
233 ease [2]. As such, the emissions associated with loading petcoke onto a train are negligible and  
234 were not considered. In addition, it is assumed that the train being used is a diesel-powered  
235 commercial cargo train that travels on existing trans-Canada routes for a distance of 3114 km, and  
236 the direct emissions of transport are considered. It is also assumed that petcoke transportation  
237 represents only a fraction of the train's cargo over its lifetime. Thus, the material, energy inputs,  
238 and emissions associated with the construction of the trains were considered negligible compared  
239 to the direct diesel emissions associated with trans-Canada transport.

### 240 **3.4.3 Electricity consumption**

241 Since electricity generation and emissions vary widely from grid to grid, each local grid's  
242 impact on the entire life cycle of the PDD process was considered. In Canada, for example, the  
243 provinces of Alberta and Ontario have a huge disparity in emissions due to the different energy  
244 sources making up the electricity grid in 2017 (Table 3). While Ontario has low carbon emissions  
245 due to its high dependency on nuclear and hydroelectric energy, Alberta is largely dependent on  
246 coal, which is inherently carbon intense. Thus, Alberta and Ontario suitably act as representative  
247 examples of electricity grids with high and low emissions. The cradle-to-grid emissions of the  
248 Ontario and Alberta electricity grids used in this analysis are shown in Table 3. These were  
249 calculated by combining the indirect emissions associated with extracting fuel sources and  
250 transporting them to electricity generation facilities [25] with the as-reported 2017 direct power  
251 generation emissions by Environment and Climate Change Canada [26], using some assumptions  
252 for average plant efficiency as noted in Table 3. These numbers are for AC, grid quality, high  
253 voltage electricity leaving the power plants and entering the grid, and does not include  
254 transportation or voltage stepdown, which is not considered in this work.

255

256 Table 3: Alberta and Ontario electricity grid: sources and emissions used in this study.

Source	Ontario			Alberta		
	% Gen. Contr.	Indirect <sup>a</sup> emissions (gCO <sub>2</sub> -eq/kWh)	Power Plant Construction & Direct Operation <sup>b</sup> emissions (gCO <sub>2</sub> -eq/kWh)	% Gen. Contr.	Indirect <sup>a</sup> emissions (gCO <sub>2</sub> -eq/kWh)	Power Plant Construction & Direct Operation <sup>b</sup> emissions (gCO <sub>2</sub> -eq/kWh)
Nuclear <sup>c</sup>	61	1.94	1.72	-	-	-
Coal <sup>d</sup>	-	-	-	60	82.16	626.24
Natural gas <sup>e</sup>	4	2.96	16.20	28	20.82	131.00
Hydro <sup>f</sup>	27	0	4.01	3	0	0.5
Other fuels <sup>g</sup>	1	-	0.95	1	-	0.03
Other renewables <sup>h</sup>	7	1.22	0.53	7	1.20	0.52
<b>Total Elec. Gen. emissions (gCO<sub>2</sub>-eq/kWh)</b>			<b>29.5</b>			<b>862</b>

257 <sup>a</sup>Consist of emissions for fuel extraction, processing, and transportation to generation facility.

258 <sup>b</sup>Includes as reported generation emissions [26] and construction/decommissioning emissions [25].

259 <sup>c</sup>Estimated based on a uranium efficiency of 60%.

260 <sup>d</sup>Estimated based on coal fired power plant of 30% efficiency.

261 <sup>e</sup>Calculated based on natural gas picking power facility of 35% efficiency.

262 <sup>f</sup>Estimated based on a hydro electricity facility of 95% efficiency.

263 <sup>g</sup>As reported data due to limited information.

264 <sup>h</sup>Calculated based on a wind farm with an average efficiency of 18%.

265

### 266 3.4.4 Cooling tower system

267 To determine the minimum energy requirements of the entire system, we used the heat  
 268 exchanger network (HEN) design described in our previous work on petcoke-to-liquid fuels  
 269 processes [9]. A mechanical evaporative cooling tower system was modeled to satisfy the plant's  
 270 cooling demands, with water being supplied from a nearby river. The electrical demands of the  
 271 tower's pump and fan were estimated using Turton et al.'s [25] correlations, assuming that an  
 272 average wet bulb temperature of 11°C would be sufficient to maintain cooling.

### 273 3.4.5 Utility & CO<sub>2</sub> capture

274 The heating duty requirements of each PDD process were also estimated based on the HEN  
 275 design. The required utilities included low-pressure steam (LPS), medium-pressure steam (MPS),  
 276 high-pressure steam (HPS), and fired heat (FH). To satisfy the different steam-pressure levels and  
 277 fired-heat demands, natural gas combustion was modeled in the prior work [14] in Aspen Plus and  
 278 fed to the steam boilers and furnace to generate steam and FH, respectively. The steam boilers and

279 furnace had efficiencies of 95% and 90%, respectively [27]. For the PDD plant scenario with CCS,  
 280 ProMax® was used in the prior work [14] to model the boiler and furnace flue gas capture so that  
 281 90% of the CO<sub>2</sub> would be captured by MDEA promoted with Piperazine. Table 4 shows the utility  
 282 plant direct emissions data used in this study. The associated flue gas emissions are the direct  
 283 emissions from natural gas combustion used to provide the heat to generate the corresponding  
 284 utility, expressed in emissions per GJ of utility delivered. The CCS cases consider 90% CO<sub>2</sub>  
 285 capture from this combusted natural gas, and also consider the additional parasitic electricity  
 286 consumption accordingly in balance of plant considerations.

287 Table 4: Plant utility conditions and direct emissions for CCS and non-CCS scenarios.

Parameters	Units	LPS	MPS	HPS	Fired heat
Temperature	°C	204	300	480	1000
Pressure	bar	4	12	50	
Associated flue gas emissions with CCS	kgCO <sub>2</sub> -eq/GJ	6.49	6.77	7.53	11.63
Associated flue gas emissions w/o CCS	kgCO <sub>2</sub> -eq/GJ	64.99	67.78	75.26	116.32

288

289 As shown in Figs. 1-3, CCS-enabled designs compress the captured CO<sub>2</sub> to a supercritical  
 290 condition (153 bar) and transport it to the sequestration site via the CO<sub>2</sub> pipeline, while the flue  
 291 gas is released into the environment. When the plant is operated without CCS, all combusted CO<sub>2</sub>  
 292 products are vented into the atmosphere.

### 293 3.4.6 CO<sub>2</sub> transport pipeline construction

294 Since CO<sub>2</sub> capture is not an integral part of liquid fuel plants, each PDD process considered  
 295 the material, energy inputs, and emissions associated with the construction and decommissioning  
 296 of a CO<sub>2</sub> transportation pipeline were estimated based on a prior NETL study [28] and expressed  
 297 on the basis of kg of CO<sub>2</sub> transported. Fugitive emissions of CO<sub>2</sub> during transportation were also  
 298 considered and included in this analysis. For the Ontario plant, captured CO<sub>2</sub> can either be stored  
 299 in existing oil and gas reservoirs or the saline aquifers [29, 30], while the Alberta location can use  
 300 the Quest carbon capture and storage facility [31]. For both locations, we assumed the transport  
 301 distance to be the same.

### 302 3.4.7 Wastewater treatment

303 The wastewater treatment (WWT) facility was not directly modeled in this study. However,  
 304 the emissions generated as a result of treating the produced wastewater were considered to be a

305 burden of the PDD plant. Thus, a WWT-facility-specific emission of 1.05 kWh/m<sup>3</sup> [32] was used,  
306 with the estimated environmental impacts being based on local grid emissions.

### 307 **3.4.8 Catalyst manufacturing**

308 The GREET model was used to obtain the material used to manufacture the catalyst, as  
309 well as the associated energy consumption and emissions data [21]. However, the emissions  
310 associated with transporting the catalyst from the manufacturing site to the PDD plant entry gate  
311 were not accounted for due to limited data. We assume that these emissions are insignificant given  
312 the amount of catalyst consumed in the overall life cycle of the process compared to the amount  
313 of product.

### 314 **3.4.9 Product transportation and distribution**

315 The emissions for the transportation and distribution (T&D) of the PDD to refueling  
316 stations were accounted for using GREET model data [21]. It was assumed that the diesel fuel  
317 would be transported via barge, pipeline, and rail, which account for 48.5%, 46.4%, and 5.1% of  
318 fuel transportation, respectively. Trucks were assumed to be used solely for local distribution.

### 319 **3.4.10 Diesel use**

320 Petcoke's end of life is assessed by evaluating the emissions for driving 1 km in a CIDI  
321 vehicle with a fuel consumption rate of 8.6 litres per 100 km. For the purpose of comparison, we  
322 also estimated the emissions to travel 1 km in a CIDI vehicle of the same fuel economy powered  
323 by conventional petroleum and oil-sands derived diesel respectively.

## 324 **4.0 Results and discussion**

### 325 **4.1 PDD plants: Alberta location**

#### 326 **4.1.1 Life cycle inventories and midpoint impacts**

327 The results of the WTW inventory at the Alberta location for each of the six PDD designs  
328 with and without CCS are shown in Table 4. For the PSG design (with or without CCS), the  
329 consumption rate is 300.2 grams of petcoke per 3.3 MJ<sub>HHV</sub> of PDD driven (distance of 1 km) and  
330 0.37 MJ<sub>HHV</sub> of gasoline produced. This corresponds to a fuel efficiency of 43.4% based on higher  
331 heating value (HHV), which is defined as the ratio of fuels produced to petcoke processed [9]. For  
332 the Alberta location, the PSG design's life cycle CO<sub>2</sub> emissions with CCS were 467.2 g/km

333 distance driven, which is equivalent to 1.56 g of CO<sub>2</sub> emitted per gram of petcoke consumed.  
 334 Without CCS, the PSG design's life cycle CO<sub>2</sub> emissions increased by 83.8%, which corresponds  
 335 to 2.86 g per gram of petcoke. To achieve the same thermal input as the PSG design (300.3 g  
 336 petcoke per km driven), the PG-INGR design must convert 183.2 grams of petcoke and 81.6 grams  
 337 of natural gas per km distance driven [9]. As a result, this design's life cycle CO<sub>2</sub> emissions were  
 338 419.4 g/km distance driven with CCS technology, which is 47.8 grams of CO<sub>2</sub> per km distance  
 339 driven emission lower than the PSG design. When PG-INGR was used without CCS, its life cycle  
 340 CO<sub>2</sub> per gram of petcoke converted was 3.74 g. Conversely, the PG-ENGR configuration had  
 341 lower emissions than the PSG design but higher than the PG-INGR configuration. This design had  
 342 life cycle CO<sub>2</sub> emissions that were 9% and 9.6% higher than those recorded for the PG-INGR  
 343 configuration with and without CCS, respectively.

344 Other significant emissions included carbon monoxide, methane, nitrogen oxides, sulfur  
 345 oxides, and the VOC, which consist of RE, AP, GWP, EP, and SF gases. As expected, the use of  
 346 CCS increased the emissions of non-CO<sub>2</sub> gases due to the parasitic load of the technology. Thus,  
 347 the trade-off between reducing GHG emissions by capturing CO<sub>2</sub> and emitting other gases which  
 348 are responsible for other environmental impacts were explored in this study.

349  
 350 Table 4: WTW inventory data for the PDD process designs with and without CCS in the  
 351 Alberta location. Note that "distance driven" is for a diesel-powered vehicle. Gasoline is as an  
 352 additional side product.

Inventory	PSG	PSG-CCS	PG-INGR	PG-INGR- CCS	PG-ENGR	PG-ENGR- CCS
<i>Input flows (kg unless otherwise specified)</i>						
Petcoke	0.300	0.300	0.183	0.183	0.206	0.206
Natural gas, in ground	0.053	0.065	0.071	0.082	0.092	0.101
Coal, raw	0.062	0.078	0.047	0.055	0.060	0.072
Hydro (MJ)	0.010	0.013	7.7 x 10 <sup>-3</sup>	9.0 x 10 <sup>-3</sup>	0.010	0.012
Other renewables (MJ)	0.113	0.143	0.087	0.102	0.111	0.133
Other fuels (MJ)	2.66 x 10 <sup>-3</sup>	3.37 x 10 <sup>-3</sup>	2.05 x 10 <sup>-3</sup>	2.40 x 10 <sup>-3</sup>	2.60 x 10 <sup>-3</sup>	3.12 x 10 <sup>-3</sup>
River water, in river	2.543	2.835	0.653	0.952	1.331	1.441
Iron ore, raw	2.46 x 10 <sup>-6</sup>	6.80 x 10 <sup>-5</sup>	2.46 x 10 <sup>-6</sup>	6.80 x 10 <sup>-5</sup>	2.46 x 10 <sup>-6</sup>	6.80 x 10 <sup>-5</sup>
Aluminium ore, raw	1.51 x 10 <sup>-6</sup>					
<i>Output flows</i>						
<i>Products flow</i>						

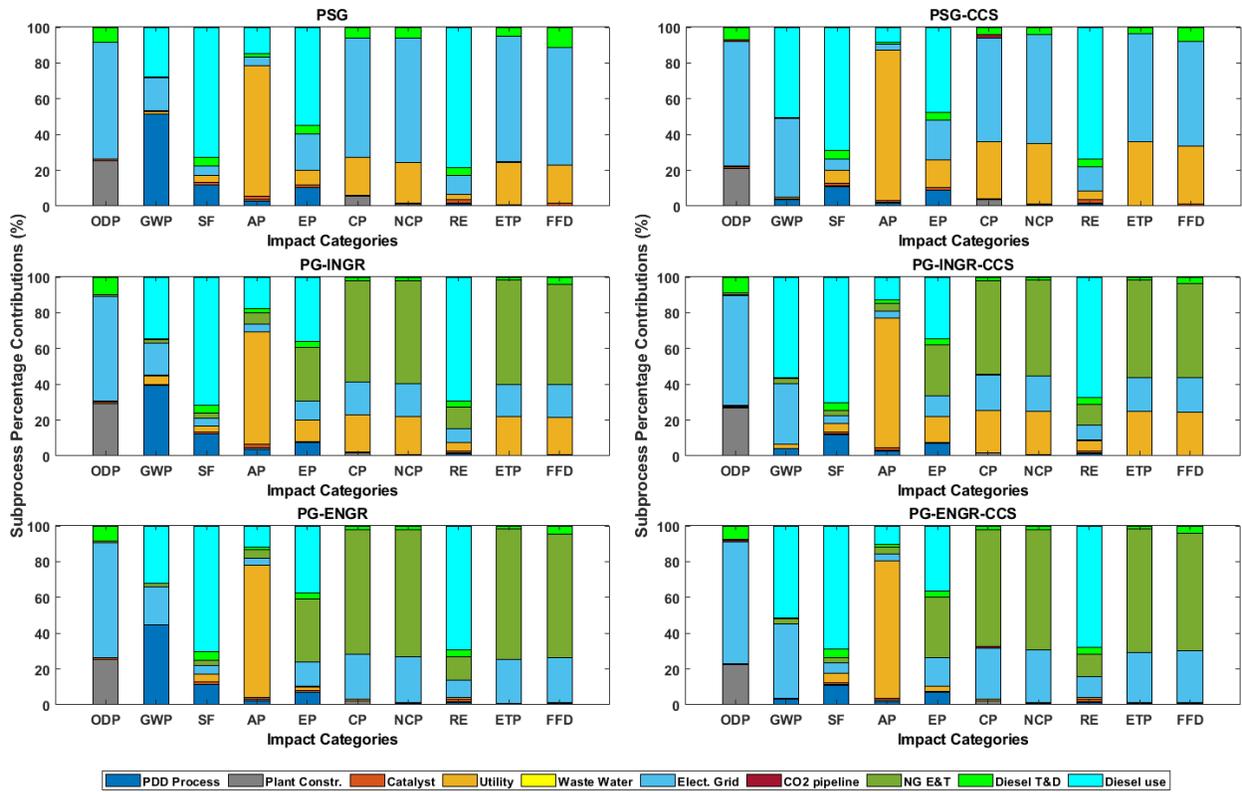
Distance driven (km)	1	1	1	1	1	1
Gasoline (MJ <sub>HHV</sub> )	1.224	1.224	1.224	1.224	1.224	1.224
Sulfur (kg)	0.017	0.017	0.010	0.010	0.012	0.012
Sequestered CO <sub>2</sub> (kg)	0	0.584	0	0.353	0	0.439
<i>Emissions flow to air (kg)</i>						
Ammonia	1.54 x 10 <sup>-8</sup>	2.12 x 10 <sup>-8</sup>	1.58 x 10 <sup>-8</sup>	1.82 x 10 <sup>-8</sup>	1.87 x 10 <sup>-8</sup>	2.17 x 10 <sup>-8</sup>
Carbon dioxide	8.59 x 10 <sup>-1</sup>	4.67 x 10 <sup>-1</sup>	6.85 x 10 <sup>-1</sup>	4.19 x 10 <sup>-1</sup>	7.47 x 10 <sup>-1</sup>	4.60 x 10 <sup>-1</sup>
Carbon monoxide	2.47 x 10 <sup>-3</sup>	2.48 x 10 <sup>-3</sup>				
Dinitrogen monoxide	6.75 x 10 <sup>-7</sup>	6.80 x 10 <sup>-7</sup>	6.57 x 10 <sup>-7</sup>	6.60 x 10 <sup>-7</sup>	6.70 x 10 <sup>-7</sup>	6.73 x 10 <sup>-7</sup>
Methane	4.92 x 10 <sup>-5</sup>	5.38 x 10 <sup>-5</sup>	9.87 x 10 <sup>-5</sup>	1.01 x 10 <sup>-4</sup>	9.14 x 10 <sup>-5</sup>	9.33 x 10 <sup>-5</sup>
Nitrogen dioxide	1.80 x 10 <sup>-7</sup>	1.84 x 10 <sup>-7</sup>	1.93 x 10 <sup>-7</sup>	1.95 x 10 <sup>-7</sup>	1.80 x 10 <sup>-7</sup>	1.83 x 10 <sup>-7</sup>
Nitrogen oxides	1.54 x 10 <sup>-4</sup>	1.63 x 10 <sup>-4</sup>	1.61 x 10 <sup>-4</sup>	1.64 x 10 <sup>-4</sup>	1.62 x 10 <sup>-4</sup>	1.66 x 10 <sup>-4</sup>
NM VOC, Non-methane volatile organic compounds	1.39 x 10 <sup>-6</sup>	1.89 x 10 <sup>-6</sup>	1.43 x 10 <sup>-6</sup>	1.64 x 10 <sup>-6</sup>	1.68 x 10 <sup>-6</sup>	1.94 x 10 <sup>-6</sup>
Particulates, > 2.50 µm, and < 10 µm	2.37 x 10 <sup>-7</sup>	5.31 x 10 <sup>-7</sup>	4.55 x 10 <sup>-7</sup>	574 x 10 <sup>-7</sup>	5.51 x 10 <sup>-7</sup>	6.57 x 10 <sup>-7</sup>
Sulfur dioxides	2.84 x 10 <sup>-6</sup>	1.15 x 10 <sup>-5</sup>	2.67 x 10 <sup>-5</sup>	3.06 x 10 <sup>-5</sup>	2.23 x 10 <sup>-5</sup>	2.61 x 10 <sup>-5</sup>
Sulfur oxides	4.12 x 10 <sup>-4</sup>	8.22 x 10 <sup>-4</sup>	2.86 x 10 <sup>-4</sup>	4.46 x 10 <sup>-4</sup>	5.12 x 10 <sup>-4</sup>	6.17 x 10 <sup>-4</sup>
VOC, volatile organic compounds	1.15 x 10 <sup>-4</sup>	1.29 x 10 <sup>-4</sup>	1.12 x 10 <sup>-4</sup>	1.17 x 10 <sup>-4</sup>	1.19 x 10 <sup>-4</sup>	1.23 x 10 <sup>-4</sup>

353  
354 Table 5 provides a comparison of the midpoint impact categories of the six PDD designs  
355 and conventional and oil-sands derived diesel. It could be observed that the ODP of PG-INGR  
356 design with CCS was 20.9% and 17.4% lower than the PSG and PG-ENGR designs respectively.  
357 When compared to the conventional diesel and oil-sands diesel, the ODP of all the PDD designs  
358 were at least 35.7% higher and 71.1% lower respectively. Fig. 4 shows that the ODP of the PDD  
359 processes mainly emanated from electricity grid (70%) and plant construction (21%). Without  
360 CCS, there was a 9-17% reduction in ODP, which is due to the extra energy required to operate  
361 the CCS technology. When CCS was employed, the PSG, PG-INGR, and PG-ENGR designs  
362 showed GWPs of 469, 422.6, and 462.7 g of CO<sub>2</sub>-eq/km distance driven, respectively, with diesel  
363 use and electricity grid emissions accounting for at least 90% of the total emissions across the PDD  
364 designs.

365 Table 5: WTW LCA results for the petcoke to diesel plant located in Athabasca, Alberta, for a basis of 1 km distance driven

Inventory	Units	PSG	PSG-CCS	PG-INGR	PG-INGR-CCS	PG-ENGR	PG-ENGR-CCS	Conv. Diesel	Oil-Sand Diesel
Ozone depletion	kg CFC-11eq	$2.93 \times 10^{-12}$	$3.52 \times 10^{-12}$	$2.53 \times 10^{-12}$	$2.78 \times 10^{-12}$	$2.92 \times 10^{-12}$	$3.37 \times 10^{-12}$	$1.79 \times 10^{-12}$	$1.22 \times 10^{-11}$
Global warming	kg CO <sub>2</sub> eq	$8.60 \times 10^{-1}$	$4.69 \times 10^{-1}$	$6.88 \times 10^{-1}$	$4.23 \times 10^{-1}$	$7.50 \times 10^{-1}$	$4.63 \times 10^{-1}$	$3.05 \times 10^{-1}$	$3.48 \times 10^{-1}$
Smog	kg O <sub>3</sub> eq	$4.39 \times 10^{-3}$	$4.64 \times 10^{-3}$	$4.54 \times 10^{-3}$	$4.64 \times 10^{-3}$	$4.61 \times 10^{-3}$	$4.70 \times 10^{-3}$	$7.02 \times 10^{-3}$	$1.20 \times 10^{-2}$
Acidification	kg SO <sub>2</sub> eq	$5.12 \times 10^{-4}$	$9.36 \times 10^{-4}$	$4.29 \times 10^{-4}$	$5.94 \times 10^{-4}$	$6.53 \times 10^{-4}$	$7.62 \times 10^{-4}$	$3.33 \times 10^{-4}$	$7.59 \times 10^{-4}$
Europhication	kg N eq	$7.59 \times 10^{-6}$	$9.02 \times 10^{-6}$	$1.26 \times 10^{-5}$	$1.33 \times 10^{-5}$	$1.20 \times 10^{-5}$	$1.25 \times 10^{-5}$	$2.01 \times 10^{-5}$	$3.60 \times 10^{-5}$
Carcinogenics	CTUh	$1.51 \times 10^{-10}$	$2.54 \times 10^{-10}$	$5.71 \times 10^{-10}$	$6.20 \times 10^{-10}$	$5.15 \times 10^{-10}$	$5.51 \times 10^{-10}$	$3.09 \times 10^{-9}$	$4.48 \times 10^{-9}$
Non Carcinogenics	CTUh	$1.88 \times 10^{-9}$	$3.10 \times 10^{-9}$	$7.19 \times 10^{-9}$	$7.76 \times 10^{-9}$	$6.47 \times 10^{-9}$	$6.86 \times 10^{-9}$	$3.17 \times 10^{-8}$	$4.39 \times 10^{-8}$
Respiratory effects	kg PM2.5 eq	$8.65 \times 10^{-6}$	$9.31 \times 10^{-6}$	$1.10 \times 10^{-5}$	$1.13 \times 10^{-5}$	$1.08 \times 10^{-5}$	$1.11 \times 10^{-5}$	$2.12 \times 10^{-5}$	$2.96 \times 10^{-5}$
Ecotoxicity	CTUe	$4.80 \times 10^{-2}$	$7.85 \times 10^{-2}$	$1.83 \times 10^{-1}$	$1.97 \times 10^{-1}$	$1.64 \times 10^{-1}$	$1.74 \times 10^{-1}$	$6.19 \times 10^{-1}$	$8.67 \times 10^{-1}$
Fossil fuel depletion	MJ surplus	$1.32 \times 10^{-1}$	$1.94 \times 10^{-1}$	$3.90 \times 10^{-1}$	$4.18 \times 10^{-1}$	$3.56 \times 10^{-1}$	$3.76 \times 10^{-1}$	$5.12 \times 10^{-1}$	$7.56 \times 10^{-1}$

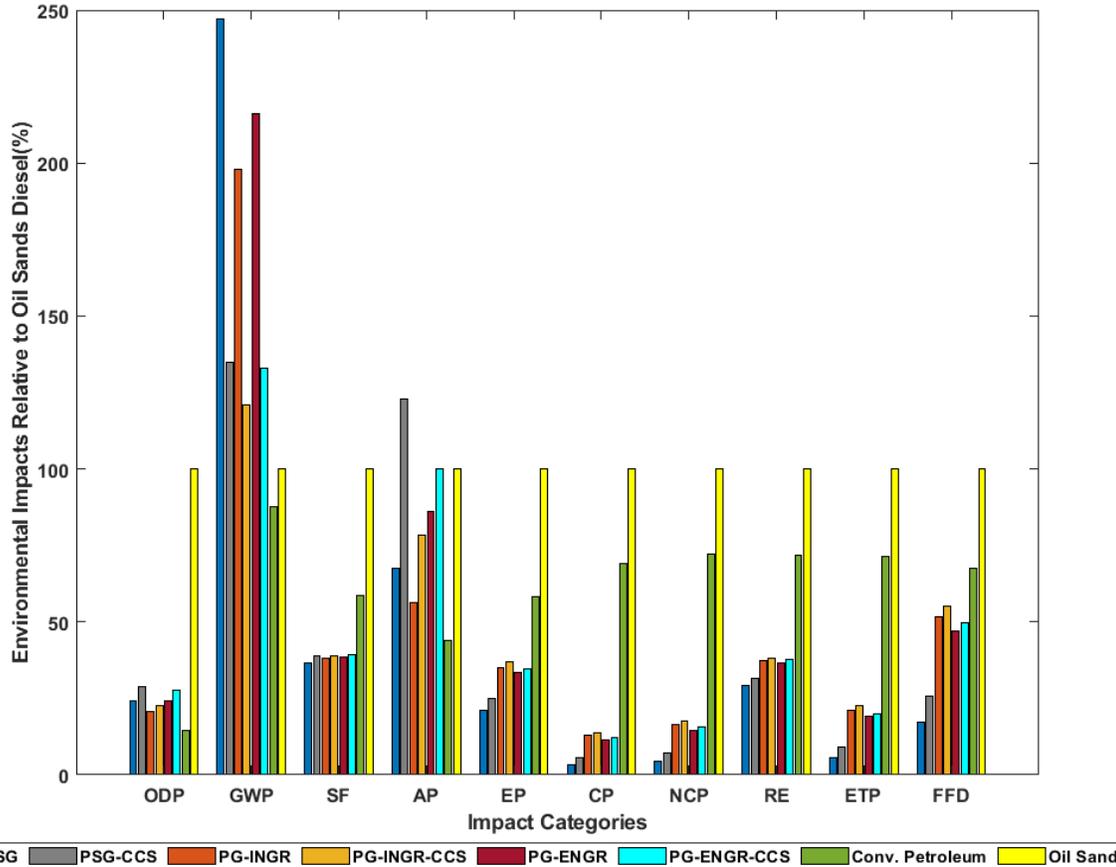
366  
367 The GWPs for the PSG, PG-INGR, and PG-ENGR designs with CCS were 53.6%, 38.4%, and 51.6% higher than that of  
368 conventional petroleum derived diesel, and 34.8%, 21.5%, and 33% higher than that of oil-sands-derived diesel, respectively (Fig. 5).  
369 Of course, there is no need to emphasize the GWP of the PDD plants when operated without CCS, as it is already evident. The emission  
370 of nitrogen oxides (NO<sub>x</sub>) and volatile organic compounds (VOC) throughout the life cycle of the PDD process contributes to smog  
371 formation (SF) in the atmosphere. The SF of the PDD designs, both with and without the use of CCS, are fairly similar. Nevertheless,  
372 the PDD designs has a SF tendency which is lower than the conventional petroleum and oil-sands derived diesel plants by 33% and  
373 60.6% respectively. The AP of the PDD plants is mainly due to the natural gas combustion to satisfy the plant utility requirements. The  
374 AP tendency of the PSG design with CCS was 57.6% and 22.8% higher than that of the PG-INGR and PG-ENGR designs, respectively  
375 due to higher utility requirement of this design [9]. While all the AP of all the PDD designs were worse compared to the conventional  
376 petroleum, the PG-INGR with CCS has an AP that is 21.7% lower than that of oil-sand derived diesel.



377

378 Figure 4: Contribution plots of the WTW life cycle emissions for the different PDD designs  
 379 in Alberta, with and without CCS.

380 Eutrophication potential (EP) refers to the tendency of a water body to become saturated  
 381 with excessive levels of nutrients, such as nitrogen and phosphorus, which are usually released by  
 382 various human and industrial activities. As can be seen in Fig. 5, the PDD configurations had lower  
 383 EP tendencies than the oil sands and conventional diesel processes of which the EP tendency of  
 384 the PDD plants became even smaller when CCS was not used. Both the PG-INGR and PG-ENGR  
 385 designs had higher EP due to natural gas consumed in the process compared to PSG design that  
 386 processed only petcoke. With regards to carcinogenic (CP) and non-carcinogenic (NCP) potentials,  
 387 all PDD designs showed impacts that were two orders of magnitude lower than those of the  
 388 reference substances. As such, CP and NCP will not be discussed further in this work. The RE of  
 389 the PSG design with CCS showed to be 17.7% and 16.2% lower than the PG-INGR and PG-ENGR  
 390 designs with CCS respectively due to the emissions emanating from the natural gas consumed in  
 391 the latter processes as feedstock.



392

393 Figure 5: Comparative WTW life cycle impact categories relative to oil-sands-derived diesel for  
 394 the Alberta plants.

395 When compared to the conventional and oil sands reference cases, the RE of the PDD  
 396 processes is lower by at least 56.1% and 68.5% respectively. In addition, the ETPs of the three  
 397 PDD configurations with CCS were found to be 87.3%, 68.1%, and 71.9% lower than that of  
 398 conventional diesel, and 91%, 77.2%, and 79.9% lower than that of oil sands diesel, respectively.  
 399 Furthermore, Fig. 5 clearly shows that the conventional and oil sands diesel processes leads to  
 400 higher FFD than the proposed PDD designs. Even when the FFD of the PG-INGR design which  
 401 causes the most FFD among the PDD processes was compared to conventional and oil sands diesel  
 402 processes, an 18.3% and 44.7% reduction was observed respectively. Thus, despite their high  
 403 GWP, these PDD designs remain promising pathways that can allow stockpiled petcoke to be  
 404 disposed of by converting it into diesel.

405 **4.2 PDD plants: Ontario location**

406 **4.2.1 Life cycle inventories and midpoint impacts**

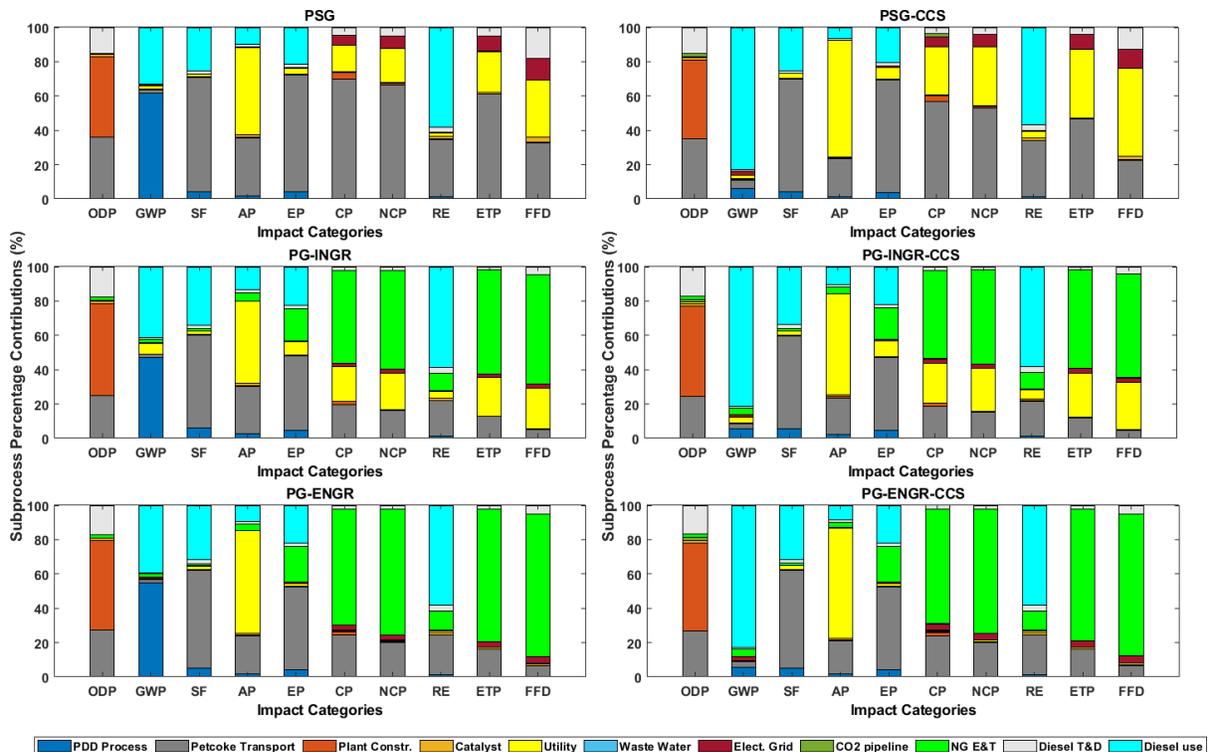
407 Table 6 presents the life cycle inventory and emissions for the WTW assessment of the  
 408 PDD plants located in Ontario. It is worth noting that the same amounts of petcoke and natural gas  
 409 were consumed in both locations.

410 Table 6: WTW inventory data for the PDD process designs with and without CCS in the Ontario  
 411 location.

Inventory	PSG	PSG-CCS	PG-INGR	PG-INGR-CCS	PG-ENGR	PG-ENGR-CCS
<i>Input flows (kg unless otherwise specified)</i>						
Petcoke	0.300	0.300	0.183	0.183	0.206	0.206
Natural gas, in ground	0.041	0.049	0.061	0.071	0.080	0.086
Uranium, raw	$1.20 \times 10^{-8}$	$1.52 \times 10^{-8}$	$9.22 \times 10^{-9}$	$1.08 \times 10^{-8}$	$1.17 \times 10^{-8}$	$1.40 \times 10^{-8}$
Hydro (MJ)	0.080	0.101	0.061	0.072	0.078	0.094
Other renewables (MJ)	$1.14 \times 10^{-1}$	$1.45 \times 10^{-1}$	$8.81 \times 10^{-2}$	$1.03 \times 10^{-1}$	$1.12 \times 10^{-1}$	$1.34 \times 10^{-1}$
Other fuels (MJ)	$1.66 \times 10^{-3}$	$2.11 \times 10^{-3}$	$1.28 \times 10^{-3}$	$1.50 \times 10^{-3}$	$1.63 \times 10^{-3}$	$1.95 \times 10^{-3}$
River water, in river	2.543	2.835	0.653	0.952	1.331	1.441
Iron ore, raw	$2.46 \times 10^{-6}$	$6.80 \times 10^{-5}$	$2.46 \times 10^{-6}$	$6.80 \times 10^{-5}$	$2.46 \times 10^{-6}$	$6.80 \times 10^{-5}$
Aluminium ore, raw	$1.51 \times 10^{-6}$					
<i>Output flows</i>						
<i>Products flow</i>						
Distance driven (km)	1	1	1	1	1	1
Gasoline (MJ <sub>HHV</sub> )	1.224	1.224	1.224	1.224	1.224	1.224
Sulfur (kg)	0.017	0.017	0.010	0.010	0.012	0.012
Sequestered CO <sub>2</sub> (kg)	0	0.584	0	0.353	0	0.439
<i>Emissions flow to air (kg)</i>						
Ammonia	$8.88 \times 10^{-8}$	$9.14 \times 10^{-8}$	$5.87 \times 10^{-8}$	$5.97 \times 10^{-8}$	$6.57 \times 10^{-8}$	$6.63 \times 10^{-8}$
Carbon dioxide	$7.15 \times 10^{-1}$	$2.79 \times 10^{-1}$	$5.71 \times 10^{-1}$	$2.87 \times 10^{-1}$	$6.02 \times 10^{-1}$	$2.82 \times 10^{-1}$
Carbon monoxide	$2.54 \times 10^{-3}$	$2.55 \times 10^{-3}$	$2.52 \times 10^{-3}$	$2.52 \times 10^{-3}$	$2.52 \times 10^{-3}$	$2.52 \times 10^{-3}$
Dinitrogen monoxide	$9.93 \times 10^{-7}$	$9.93 \times 10^{-7}$	$8.48 \times 10^{-7}$	$8.48 \times 10^{-7}$	$8.81 \times 10^{-7}$	$8.81 \times 10^{-7}$
Methane	$5.91 \times 10^{-5}$	$6.14 \times 10^{-5}$	$1.03 \times 10^{-4}$	$1.04 \times 10^{-4}$	$9.57 \times 10^{-5}$	$9.57 \times 10^{-5}$
Nitrogen dioxide	$1.80 \times 10^{-7}$	$1.84 \times 10^{-7}$	$1.93 \times 10^{-7}$	$1.95 \times 10^{-7}$	$1.80 \times 10^{-7}$	$1.83 \times 10^{-7}$
Nitrogen oxides	$4.98 \times 10^{-4}$	$5.03 \times 10^{-4}$	$3.70 \times 10^{-4}$	$3.70 \times 10^{-4}$	$3.96 \times 10^{-4}$	$3.96 \times 10^{-4}$
NM VOC, Non-methane volatile organic compounds	$2.11 \times 10^{-5}$	$2.13 \times 10^{-5}$	$1.33 \times 10^{-5}$	$1.34 \times 10^{-5}$	$1.49 \times 10^{-5}$	$1.50 \times 10^{-5}$
Particulates, > 2.50 µm, and < 10 µm	$8.68 \times 10^{-6}$	$8.92 \times 10^{-6}$	$5.58 \times 10^{-6}$	$5.68 \times 10^{-6}$	$6.27 \times 10^{-6}$	$6.34 \times 10^{-6}$
Sulfur dioxides	$1.73 \times 10^{-5}$	$2.15 \times 10^{-5}$	$1.80 \times 10^{-5}$	$1.99 \times 10^{-5}$	$1.08 \times 10^{-5}$	$1.11 \times 10^{-5}$
Sulfur oxides	$4.13 \times 10^{-4}$	$8.22 \times 10^{-4}$	$2.86 \times 10^{-4}$	$4.46 \times 10^{-4}$	$5.12 \times 10^{-4}$	$6.17 \times 10^{-4}$
VOC, volatile organic compounds	$1.14 \times 10^{-4}$	$1.27 \times 10^{-4}$	$1.11 \times 10^{-4}$	$1.16 \times 10^{-4}$	$1.18 \times 10^{-4}$	$1.21 \times 10^{-4}$

412

413 As shown in the system boundary, the main differences between the two locations were the impacts  
 414 of transporting the petcoke from Alberta to Ontario and the emissions of their respective electricity  
 415 grids. Thus, the life cycle CO<sub>2</sub> emissions of the PSG design operating with CCS in this location  
 416 were 279.2 g/km distance driven, which is 40.2% lower than the PSG for the Alberta location.  
 417 Similarly, life cycle CO<sub>2</sub> emissions for the PG-INGR and the PG-ENGR designs with CCS were  
 418 287.4 and 281.7 gCO<sub>2</sub>-eq/km distance driven, respectively. Unlike the Alberta plants, which  
 419 differed significantly in terms of life cycle CO<sub>2</sub> emissions, none of the three designs operating with  
 420 CCS in Ontario were clearly superior with respect to CO<sub>2</sub> emissions reduction. Although the  
 421 Ontario location had lower life cycle CO<sub>2</sub> emissions, all the PDD designs produced higher levels  
 422 of carbon monoxide, methane, NO<sub>x</sub>, and VOC due to petcoke transportation emissions. Thus, this  
 423 work intends to present and analyze the overall environmental benefits of such trade-offs in plant  
 424 location.



425  
 426 Figure 6: Contribution plots of the WTW life cycle emissions of the different PDD designs with  
 427 and without CCS, located in Ontario.

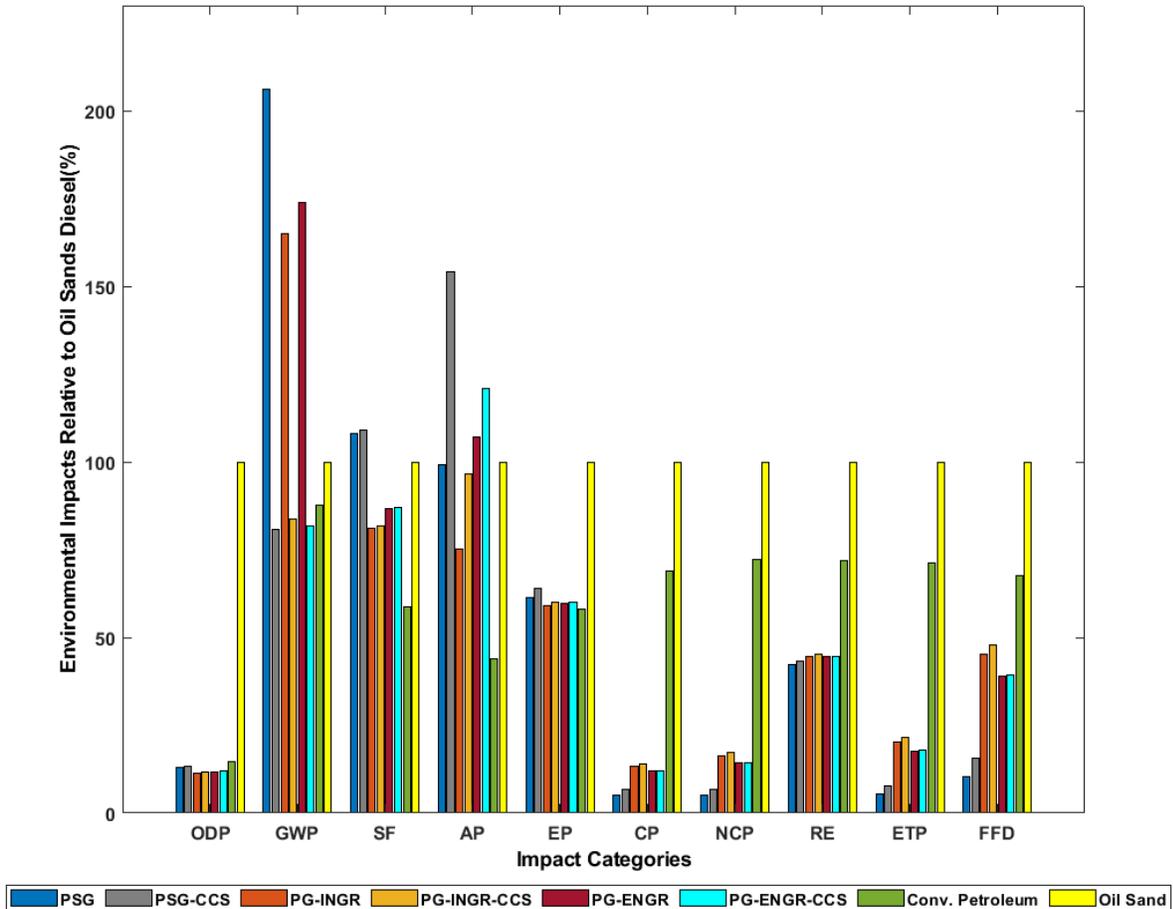
428 Table 7: WTW LCA results for the petcoke to diesel plant located in Sarnia, Ontario, for a basis of 1 km distance driven

Inventory	Units	PSG	PSG-CCS	PG-INGR	PG-INGR-CCS	PG-ENGR	PG-ENGR-CCS	Conv. Diesel	Oil-Sand Diesel
Ozone depletion	kg CFC-11eq	$1.57 \times 10^{-12}$	$1.61 \times 10^{-12}$	$1.39 \times 10^{-12}$	$1.41 \times 10^{-12}$	$1.43 \times 10^{-12}$	$1.45 \times 10^{-12}$	$1.79 \times 10^{-12}$	$1.22 \times 10^{-11}$
Global warming	kg CO <sub>2</sub> eq	$7.17 \times 10^{-1}$	$2.81 \times 10^{-1}$	$5.75 \times 10^{-1}$	$2.91 \times 10^{-1}$	$6.06 \times 10^{-1}$	$2.85 \times 10^{-1}$	$3.05 \times 10^{-1}$	$3.48 \times 10^{-1}$
Smog	kg O <sub>3</sub> eq	$1.29 \times 10^{-2}$	$1.31 \times 10^{-2}$	$9.68 \times 10^{-3}$	$9.76 \times 10^{-3}$	$1.04 \times 10^{-2}$	$1.04 \times 10^{-2}$	$7.02 \times 10^{-3}$	$1.20 \times 10^{-2}$
Acidification	kg SO <sub>2</sub> eq	$7.52 \times 10^{-4}$	$1.17 \times 10^{-3}$	$5.71 \times 10^{-4}$	$7.33 \times 10^{-4}$	$8.12 \times 10^{-4}$	$9.17 \times 10^{-4}$	$3.33 \times 10^{-4}$	$7.59 \times 10^{-4}$
Europhication	kg N eq	$2.21 \times 10^{-5}$	$2.31 \times 10^{-5}$	$2.12 \times 10^{-5}$	$2.17 \times 10^{-5}$	$2.15 \times 10^{-5}$	$2.16 \times 10^{-5}$	$2.01 \times 10^{-5}$	$3.60 \times 10^{-5}$
Carcinogenics	CTUh	$2.29 \times 10^{-10}$	$2.96 \times 10^{-10}$	$5.97 \times 10^{-10}$	$6.30 \times 10^{-10}$	$5.31 \times 10^{-10}$	$5.41 \times 10^{-10}$	$3.09 \times 10^{-9}$	$4.48 \times 10^{-9}$
Non Carcinogenics	CTUh	$2.26 \times 10^{-9}$	$3.03 \times 10^{-9}$	$7.16 \times 10^{-9}$	$7.56 \times 10^{-9}$	$6.27 \times 10^{-9}$	$6.34 \times 10^{-9}$	$3.17 \times 10^{-8}$	$4.39 \times 10^{-8}$
Respiratory effects	kg PM2.5 eq	$1.25 \times 10^{-5}$	$1.28 \times 10^{-5}$	$1.32 \times 10^{-5}$	$1.33 \times 10^{-5}$	$1.31 \times 10^{-5}$	$1.32 \times 10^{-5}$	$2.12 \times 10^{-5}$	$2.96 \times 10^{-5}$
Ecotoxicity	CTUe	$4.80 \times 10^{-2}$	$6.78 \times 10^{-2}$	$1.77 \times 10^{-1}$	$1.87 \times 10^{-1}$	$1.53 \times 10^{-1}$	$1.55 \times 10^{-1}$	$6.19 \times 10^{-1}$	$8.67 \times 10^{-1}$
Fossil fuel depletion	MJ surplus	$7.80 \times 10^{-2}$	$1.17 \times 10^{-1}$	$3.43 \times 10^{-1}$	$3.63 \times 10^{-1}$	$2.95 \times 10^{-1}$	$2.98 \times 10^{-1}$	$5.12 \times 10^{-1}$	$7.56 \times 10^{-1}$

429

430 Table 7 shows the midpoint impact categories of the plants in Ontario. Due to the low grid carbon intensity at this location, plant  
431 construction, petcoke transport, and diesel transportation and distribution (T&D) are primarily the source of ODP (Fig. 6). When CCS  
432 was employed, the PSG, PG-INGR, and PG-ENGR designs at the Ontario location had GWPs that were 40%, 31.2%, and 38.4% lower  
433 than those of the Alberta plants, respectively. Interestingly, the PSG design with CCS at the Ontario location had WTW GHG emissions  
434 of 281.3 gCO<sub>2</sub>-eq/km distance driven which slightly outperformed the PG-INGR and PG-ENGR designs by 3% and 1%, respectively.  
435 This is because the PSG design consumed more electricity than the PG-INGR and PG-ENGR designs of which it is a huge contributor  
436 (44%) to GHG emissions at the Alberta location. However, at this location, the electricity grid GHG emission is minimal (2%), thus  
437 resulting to a reduced total GHG emission. Furthermore, the PSG design was able to reduce GHG emissions by 8% and 19% compared  
438 conventional petroleum and oil-sands derived diesel, respectively. Although the PG-INGR and PG-ENGR with CCS designs consumed  
439 natural gas, at least 29.2% and 41.8% reduction in FFD was achieved when compared to conventional and oil-sands diesel respectively.  
440 This reduction in GHG emissions not only demonstrates that the proposed PDD configurations offer an environmentally friendly petcoke  
441 disposal pathway, but, most importantly, it highlights petcoke's potential as a feedstock for diesel production. Although this study did

442 not consider the credits accrued from displacing more oil sand or conventional petroleum  
 443 extraction for diesel fuel production, the benefits of such approaches can further offset the  
 444 emissions of PDD processes.



445  
 446 Figure 7: Comparative WTW life cycle impact categories relative to oil-sands derived diesel for  
 447 the Ontario plants.

448 Except for FFD, it is unsurprising to notice the increase in other impact categories due to  
 449 the emissions accrued during the transportation of the petcoke to Ontario. The increase in the  
 450 environmental impacts of the PDD designs illustrates how a trade-off between GHG emissions  
 451 savings and increase in the emissions of other impact categories must be made for plants located  
 452 in Ontario. Compared to the plants located in Alberta, the PSG, PG-INGR, and PG-ENGR plants  
 453 in Ontario were able to reduce FFD by 39.6%, 13.3%, and 20.8% when operated with CCS,  
 454 respectively. However, considering the impact of the grid only, there is up to 88.2% reduction in  
 455 FFD for the plants located in Ontario compared to Alberta. This is not surprising as the Alberta  
 456 electricity grid is still almost exclusively dependent on fossil fuels. Overall, the environmental

457 benefits of locating a plant within a low carbon intensive electricity grid, such as Ontario, are  
 458 clearly evidenced by the reduced FFD, which directly correlates to reduced GHG emissions. Thus,  
 459 it can be concluded that an electricity grid which is less dependent of fossil sources like Ontario's  
 460 is most desirable when attempting to build a PDD plant. To make a decision of which of the PDD  
 461 designs with CCS to build in Ontario based on GHG emissions (at least due to the attention GWP  
 462 has received in recent years), the choice of which plant to adopt is not clear given the negligible  
 463 difference in GHG emissions among the designs. Thus, an important metric that compares the cost  
 464 invested to avoid CO<sub>2</sub> emissions termed cost of CO<sub>2</sub> avoided (CCA) [33] is computed to aid in the  
 465 decision making.

#### 466 **4.5 Cost of CO<sub>2</sub> Avoided**

467 In this study, the cost of CO<sub>2</sub> avoided (CCA) defined as the difference in the minimum  
 468 diesel selling price (MDSP) of the PDD process compared to a “status quo” reference process (oil-  
 469 sands-derived diesel) divided by the difference in emissions between both processes as shown by  
 470 equation 1:

$$471 \frac{MDSP_{PDD} - MDSP_{Ref}}{GWP_{Ref} - GWP_{PDD}} \quad (1)$$

472 where  $MDSP_{PDD}$  and  $GWP_{PDD}$  are the minimum diesel selling price and WTW GWP of the PDD  
 473 plants while  $MDSP_{Ref}$  and  $GWP_{ref}$  are the minimum diesel selling price and WTW GWP of the  
 474 oil sands diesel process respectively.

475 Most of the detailed costs data for the calculation of the CCA can be found in our  
 476 economics work [9]. In this study, we used the cost estimates from the prior work, but then in this  
 477 work we included additional information such as the capital (CAPEX) and operating (OPEX) costs  
 478 of the hot utilities generation and its flue gas CO<sub>2</sub> capture system (including compression to 153  
 479 bar). In addition, petcoke transportation and CO<sub>2</sub> sequestration costs of \$5.92 per tonne [34] and  
 480 \$13.82 per tonne [35] in 2017 US dollars respectively were used. For the reference plant, oil sand  
 481 diesel, the MDSP used was the 2017 average refinery diesel wholesale price of \$10.1 per GJ<sub>HHV</sub>  
 482 [36] with an assumed \$1.6 per GJ<sub>HHV</sub> refinery margin while the WTW GWP was 105 kgCO<sub>2</sub>-  
 483 eq/GJ<sub>HHV</sub> diesel driven.

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Table 8: CCA calculation for the three PDD plants with CCS enabled.

	PSG	PG-INGR	PG-ENGR
Total capital investment (M\$)	1174	1176	1172
Operating Cost (M\$/yr)	320	362	358
MDSP (\$/GJ)	15.0	12.6	14.2
WTW GWP (kgCO <sub>2</sub> -eq/GJ)	85.2	88.1	85.9
CCA (\$/tonneCO <sub>2</sub> -eq)	243	144	213

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As can be seen in Table 8, although the PG-INGR design showed to have the highest GWP, its CCA 40.9% and 32.7% lower than the PSG and PG-ENGR designs respectively. Thus, when the GWP and CCA of the proposed PDD designs are considered, the PG-INGR design showed to most the viable configuration.

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#### 4.6 Sensitivity Analysis

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This section presents a sensitivity analysis of the key parameters that were used in conducting the LCA in order to ascertain which parameters are most critical to the system's performance. Specifically, sensitivity analyses were performed for GWP and FFD for the Ontario plants with CCS, as these plants had the lowest environmental impacts for these categories. The studied parameters were transport distance, electricity consumption, and vehicle fuel efficiency. During the analysis, one parameter was manipulated, while all other parameters were kept constant. Fig. 8(a) shows how GHG emissions are affected by a 20% increase or decrease in the parameters. Unsurprisingly, a 20% decrease in vehicle fuel efficiency resulted in a WTW GWP of 337.6 gCO<sub>2</sub>-eq/km distance driven.

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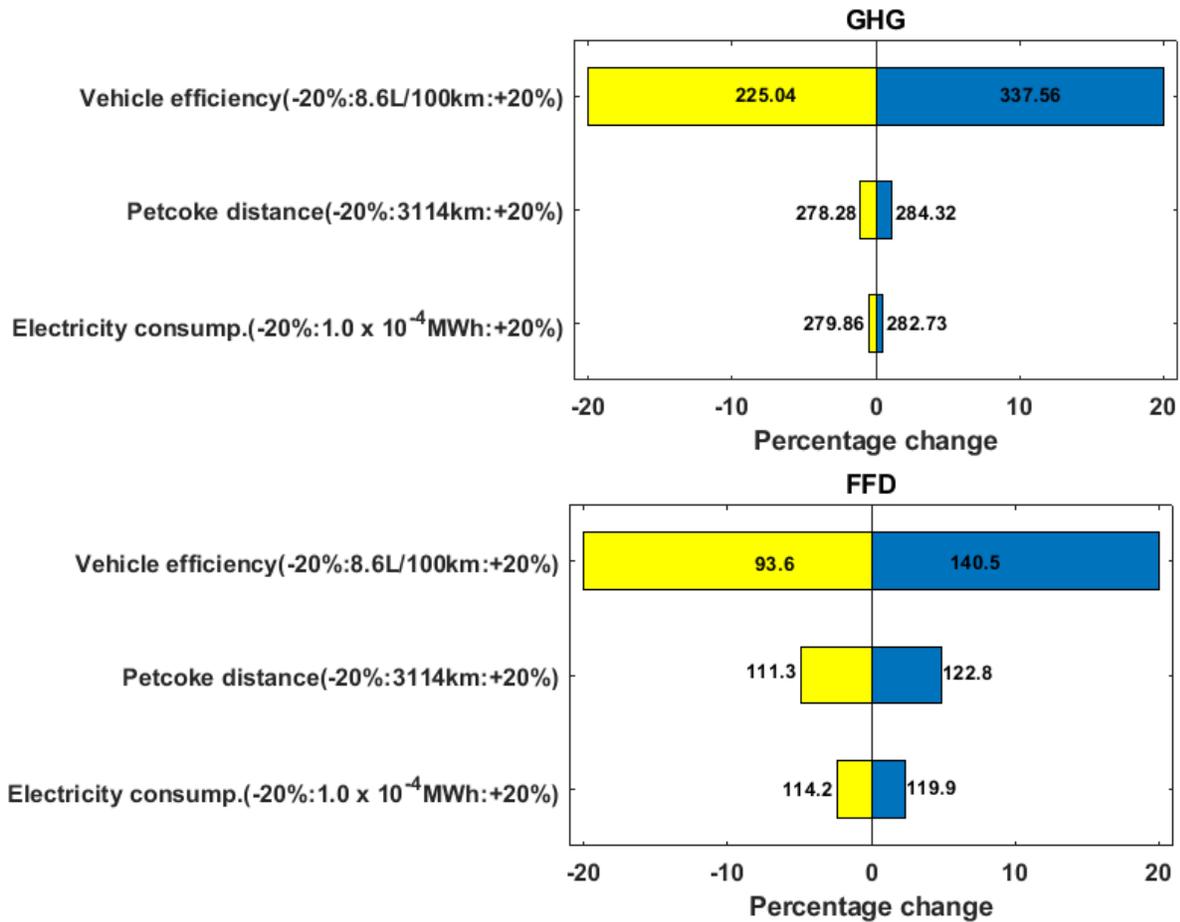
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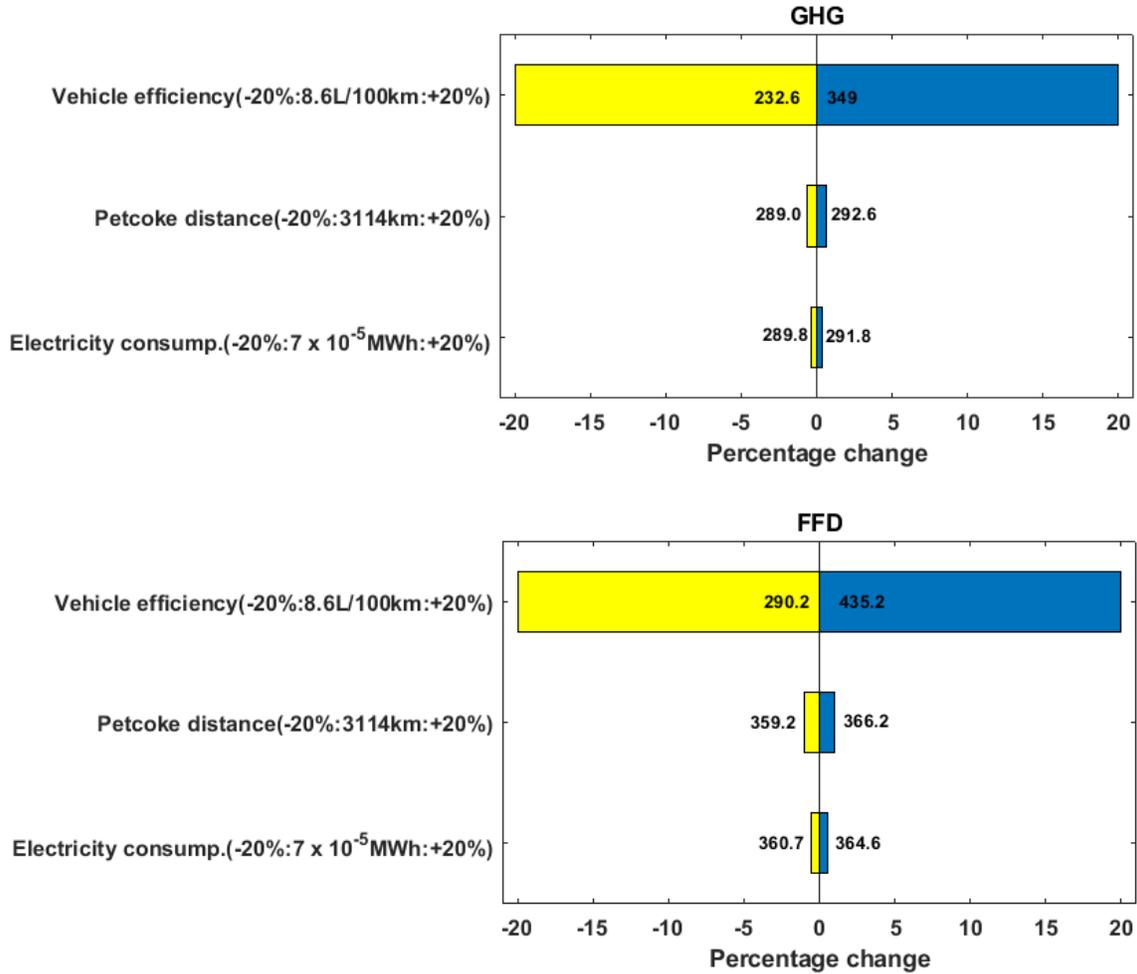


509

510 Figure 8: Sensitivity analysis of key parameters on (a) GHG emissions, (b) and FFD for the PSG  
 511 design located in Ontario.

512 In a situation where the PDD diesel is used in a vehicle with improved fuel efficiency, the  
 513 GWP dropped to 225 gCO<sub>2</sub>-eq/km distance driven. Between petcoke transport distance and  
 514 electricity, the former showed to have lower effect on GWP when increased or decreased by 20%.  
 515 Similarly, the effect of these parameters on FFD was also examined, as is shown in Fig. 8(b). When  
 516 the fuel economy of the passenger vehicle is reduced by 20%, it increases FFD to 140.5 MJ surplus  
 517 per km distance driven as more resources is consumed to achieve the same distance driven whereas  
 518 at an improved vehicle fuel economy, a 93.6 MJ surplus per km distance driven was recorded.  
 519 Overall, it showed that the WTW of PDD is largely dependent on the type of vehicle used.

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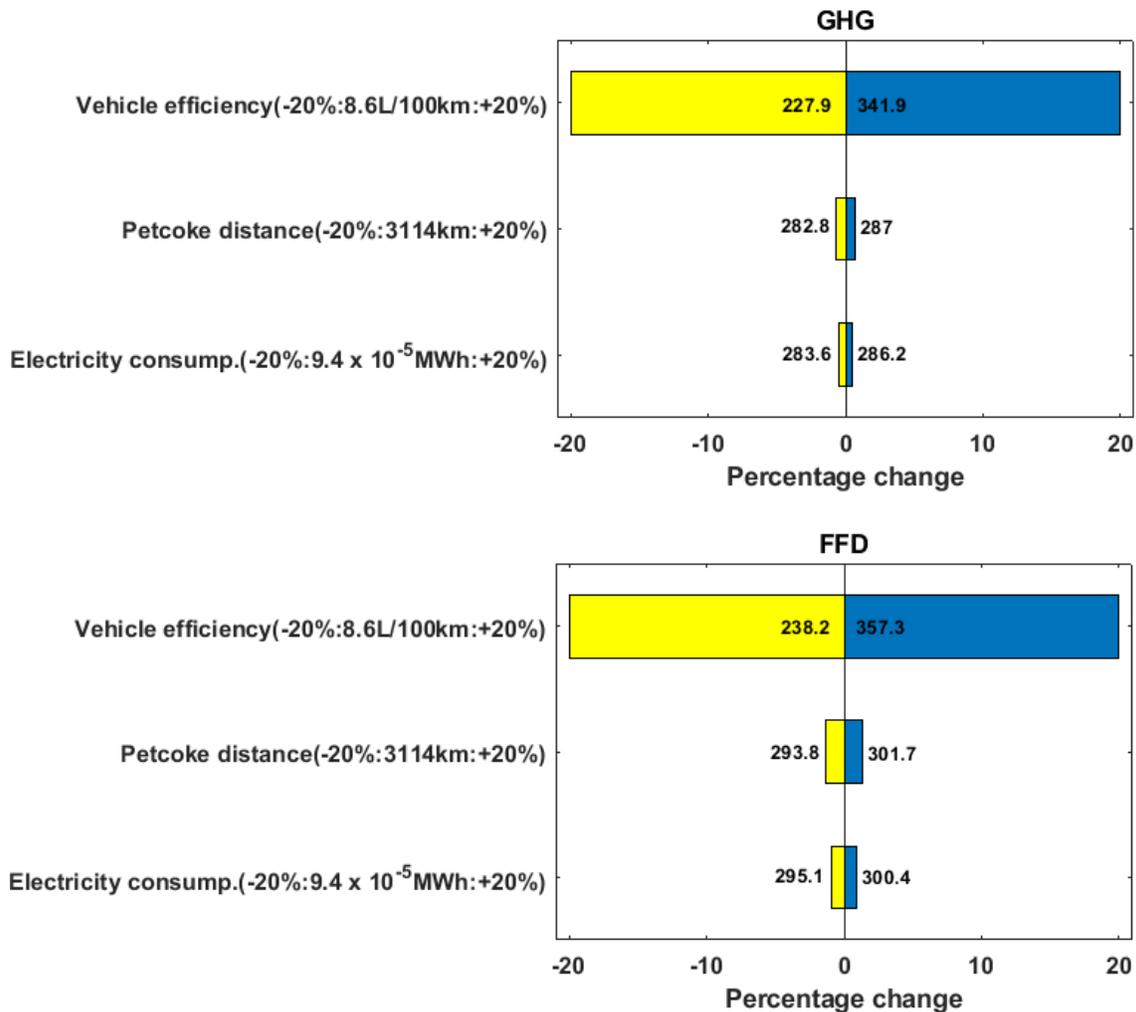
521

522 Figure 9: Sensitivity analysis of key parameters on (a) GHG emissions, and (b) FFD for the PG-  
 523 INGR design located in Ontario.

524 As shown in Fig. 9(a), compared to the PSG design, which had a GWP of 337.6 gCO<sub>2</sub>-eq/  
 525 km distance driven when vehicle efficiency was decreased by 20%, the PG-INGR design showed  
 526 a GWP of up to 349 gCO<sub>2</sub>-eq/km distance driven. In addition, increasing or decreasing electricity  
 527 consumption and petcoke travel distance did not improve the PG-INGR design in terms of GHG  
 528 emissions and FFD (fig 9(b)) in comparison to the PSG design.

529 As shown in Fig. 10(a), decreasing vehicle efficiency for the PG-ENGR design caused the GWP  
 530 to increase to 341.9 gCO<sub>2</sub>-eq/km distance driven from the base case value of 284.8 gCO<sub>2</sub>-eq/km  
 531 distance driven. Regardless, this 20% drop in vehicle efficiency still resulted in GWPs for the three  
 532 proposed designs that were lower than the GWP for oil-sands-derived diesel, which had WTW  
 533 GHG emissions in the range of 357.3 – 1179.2 gCO<sub>2</sub>-eq/km distance driven. Similarly, a lower

534 depletion of fossil resources is observed when the vehicle fuel economy was improved as depicted  
 535 in Fig. 10(b) with electricity consumption and petcoke transport distance having little effects.



536

537 Figure 10: Sensitivity analysis of key parameters on (a) GHG emissions, and (b) FFD for the PG-  
 538 ENGR design located in Ontario.

### 539 5.0 Conclusions

540 This paper has presented the results of an environmental impact assessment of six novel  
 541 processes that combines petcoke gasification and natural gas reforming to produce diesel. The  
 542 scope of analysis for this assessment included the direct and indirect material and energy inputs,  
 543 along with their associated products and emissions. A total of three designs in both high (Alberta)  
 544 and low (Ontario) electricity grid emissions locations were studied with and without carbon

545 capture and sequestration technology in order to ascertain how design and location affect overall  
546 life cycle environmental performance.

547 For the Alberta location, the PSG, PG-INGR, and PG-ENGR designs without CCS released  
548 up to 860.4, 688.2, and 750 gCO<sub>2</sub>-eq/km distance driven, respectively; when CCS technology was  
549 incorporated, these figures dropped to 469, 422.6, and 462.7 gCO<sub>2</sub>-eq/km distance driven..  
550 However, the WTW GHG emissions for the PSG, PG-INGR, and PG-ENGR designs in Ontario  
551 were 281.3, 290.7, and 284.8 gCO<sub>2</sub>-eq /km distance driven when operated with CCS. As all CCS  
552 plants in Ontario had almost equal GHG emissions, the cost of running each design (CCA) was  
553 considered which showed that the PG-INGR is more economically feasible, with a best case CCA  
554 of about \$144/tonne. This CCA is low enough to make it an attractive option for strictly GHG  
555 reduction purposes compared to other transportation fuel GHG-reduction efforts such as bio-  
556 ethanol of about \$227 to 680/tCO<sub>2</sub>eq [37, 38], fermentation-based bio-butanol of about \$470 to  
557 900/ tCO<sub>2</sub>eq [39], or thermochemical bio-butanol of about \$130 to 265/ tCO<sub>2</sub>eq [40].

558 Moreover, each of the proposed designs had a lower FFD than the conventional petroleum  
559 and oil sands diesel processes, both with and without the use of CCS technology. For all other  
560 studied environmental impacts, the proposed designs had lower environmental impacts at least  
561 when compared to the oil sands diesel processes when CCS was used. Hence, this analysis  
562 demonstrates that the proposed petcoke conversion strategies provide WTW GHG emissions levels  
563 that are competitive with those of the conventional petroleum-derived diesel process, and superior  
564 to those of the oil sands process.

565 Future work will include a comparative environmental impact assessment of processes that  
566 convert petcoke to electricity, as well an environmental impact assessment of the status quo  
567 (petcoke stockpiling). The findings of such research will help inform stakeholders about the  
568 potential benefits and trade-offs offered by disposing of petcoke via power production or liquid  
569 fuels production instead of stockpiling.

## 570 **Nomenclature**

### 571 Abbreviations

572 AP                    Acidification potential

573	CAPEX	Capital expenditure
574	CCA	Cost of CO <sub>2</sub> avoided
575	CCS	Carbon capture and storage
576	CP	Carcinogenic potential
577	EP	Eutrophication potential
578	ETP	Ecotoxicity potential
579	FFD	Fossil fuel depletion
580	FT	Fischer-Tropsch
581	GHG	Greenhouse gas
582	GWP	Global warming potential
583	HEN	Heat exchanger network
584	LCA	Life cycle assessment
585	MDSP	Minimum diesel selling price
586	MDEA	Methyl di-ethanolamine
587	NCP	Non-carcinogenic potential
588	ODP	Ozone depletion potential
589	OPEX	Operating expenditure
590	PDD	Petcoke derived diesel
591	PSG	Petcoke standalone gasification
592	PG-INGR	Petcoke integrated natural gas gasification
593	PG-ENGR	Petcoke external natural gas gasification
594	RE	Respiratory effects
595	SF	Smog formation

596 **5. Acknowledgments**

597 Support for this research was made possible through funding from an NSERC Discovery grant  
598 (RGPIN-2016-06310).

599

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