NATIONAL ENERGY TECHNOLOGY LABORATORY

H_2 PRODUCTION VIA PLASMA PYROLYSIS OF NATURAL GAS

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EXECUTIVE SUMMARY

A techno-economic analysis (TEA) performed on a single representation of a plasma pyrolysis process is summarized in this study. Key performance and cost metrics including H_2 and carbon recovery efficiencies (%), combined energy efficiency (%), and levelized cost of hydrogen (LCOH) ($/kg H_2) with accompanying sensitivity analyses are provided.

Design basis assumptions were defined for use in model development. The site location was selected to be a generic United States Midwest location. Hydrogen (H_2) product specification was defined at 99.9 vol% purity, a plant capacity of 7,800 kg/hr (17,196 lb/hr) was determined, and a capacity factor of 85 percent was chosen. The capital costs were determined by scaling existing capital costs; the costs fall within AACE International Class 5 estimates, which carry an error of -25 to +50 percent. Feedstock and coproduct prices were assumed to be $4.24/GJ ($4.47/MMBtu) for natural gas, $65.2/MWh for grid electricity, and $460/tonne ($417/ton) for carbon nanoparticles.

The results of the TEA showed that the H_2 recovery efficiency of the plasma pyrolysis system is 83.9 percent, and the carbon recovery efficiency is 97.8 percent. The plant consumes 214 MWe of electricity. The combined energy efficiency is 62.6 percent on a higher heating value basis.

Sensitivity analyses provide insight into the effect on LCOH due to changes in key variables. Among the most impactful are the value of carbon product sold and electricity price paid for plant operation. The study shows that an LCOH of $1/kg H_2 is achievable if the plant owner invests capital to produce a market-ready carbon end-product and has access to low power prices.

The results from the study can guide research, development, and demonstration to drive reductions in costs. For example, electricity consumption is a key cost driver, so emphasis should be placed on reducing electrical demand of the plasma torch or sourcing electricity from low-cost energy sources. Furthermore, optimizing the carbon product quality and value is important to take advantage of sales revenue.

1 INTRODUCTION

The purpose of this report is to evaluate the performance and cost of plasma pyrolysis of natural gas for hydrogen solid carbon production, by performing a techno-economic analysis (TEA) of a representative process. TEAs are a means of evaluating the cost and performance of a technology and are developed for a variety of purposes, including to establish a commercial benchmark; estimate the commercial potential of a technology; inform research, development, and demonstration (RD&D) priorities; inform business or policy decisions; and assess economic uncertainty and risk. The goal is to present results in a consistent and transparent manner, following National Energy Technology Laboratory (NETL) Quality Guidelines for Energy System Studies (QGESS) documents, wherever applicable.

1.1 BACKGROUND

Pyrolysis can be described as the decomposition of hydrocarbon species within the natural gas feedstock (methane, ethane, etc.) into molecular H_2 and solid carbon nanoparticles. The carbon coproduct has the potential to be sold, providing additional revenue to the plant that can reduce the cost of H_2. Furthermore, the pyrolysis chemistry does not directly include the creation of carbon dioxide (CO_2), which limits the stack CO_2 emissions of the plant without the use of CO_2 capture technology.

Natural gas pyrolysis encompasses three major concepts: catalytic, thermal, and plasma. Catalytic pyrolysis is a novel technology with a technology readiness level (TRL) of 3 and has been the focus of recent RD&D efforts. A benefit of catalytic pyrolysis is comparatively low-temperature operation in the range of 800–1,100 °C (1,472–2,012 °F); challenges include catalyst separation from carbon and deactivation issues (Schneider, Bajohr, Graf, & Kolb, 2020). Thermal pyrolysis operates at higher temperatures of 1,000–1,400 °C (1,832–2,552 °F) and has a TRL of 3–4; however, no recent developments exist for this type of pyrolysis and only limited data are available (Schneider, Bajohr, Graf, & Kolb, 2020). Plasma pyrolysis includes concepts categorized as thermal plasma such as a plasma torch powered by direct current, radio frequency, or microwaves as well as concepts categorized as non-thermal plasma such as dielectric barrier discharge, gliding arc, or electron beam (Kerscher, et al., 2021). Currently, the most advanced natural gas pyrolysis concept is thermal plasma torch pyrolysis, which is the focus of the balance of this report. The TRL is 6–8 and is currently operated as a commercial process by Monolith® Inc. (Monolith) (Schneider, Bajohr, Graf, & Kolb, 2020). Due to the use of plasma chemistry, it operates at temperatures greater than 2,000 °C (3,632 °F), which introduces challenges associated with plasma torch lifetime and high energy consumption.

1.2 OBJECTIVE

The objective of this study is to evaluate the performance and cost of a single representation of a natural gas plasma pyrolysis system by performing a TEA. TEAs are a means of evaluating the cost and performance of a technology and are often developed to

- Establish commercial benchmarks
- Inform RD&D priorities
- Inform business or policy decisions
- Enable technology comparisons
- Assess economic uncertainty and risk

Key metrics for the TEA include the H_2 recovery efficiency (%), combined energy efficiency (%), and levelized cost of hydrogen (LCOH) ($/kg H_2). Sensitivity analyses were conducted to provide insight into the effects of changes in key variables on the LCOH. The sensitivity analyses can guide RD&D to drive improvements in performance and cost.

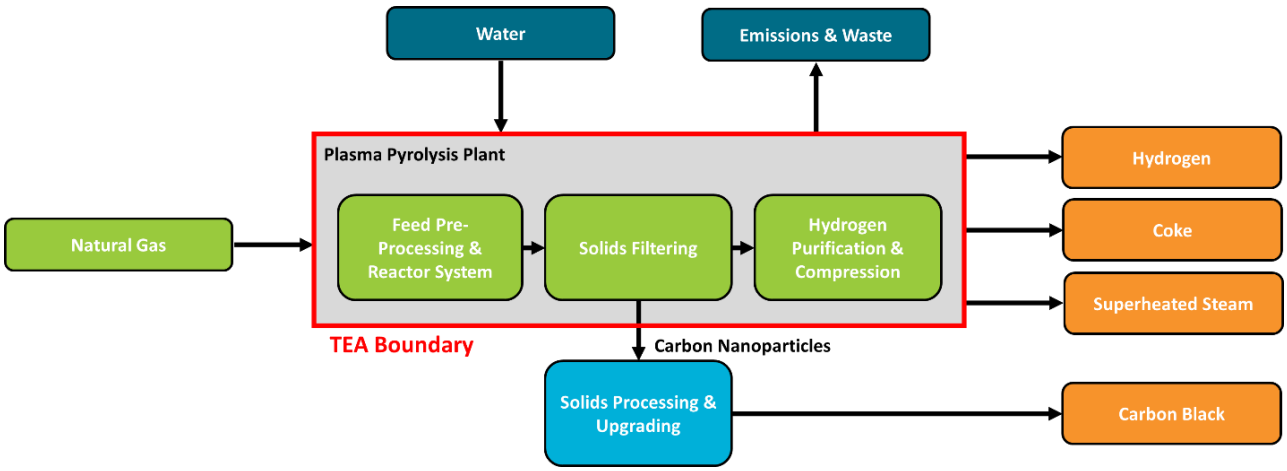
2 METHODS

This section discusses the design basis for the study. NETL has standardized assumptions for process modeling and cost analysis in its Quality Guidelines for Energy System Studies (QGESS) documents. QGESS guidance was followed where applicable, with changes or clarifications noted.

2.1 SYSTEM BOUNDARY

The boundary for the plasma pyrolysis system considered was defined for the TEA according to the red line in Exhibit 2-1. The boundary for the TEA starts at the plant gate where natural gas enters and extends through H_2 purification and compression. Because the focus of this study is H_2 production, a specific carbon end product (e.g., classified carbon black, activated carbon (ASTM, 2022)) was not considered within the baseline TEA boundary. Instead, the various options for the carbon coproduct are explored in a cost sensitivity analysis discussed in Section 3.4.1. The carbon nanoparticle product exiting the TEA system boundary can be understood as the feedstock to a co-located, unspecified carbon end product production facility.

Exhibit 2-1. System boundary defined for the TEA



2.2 SITE CHARACTERISTICS

A generic location in the U.S. Midwest was selected as the plant site. This selection is consistent with the location of Monolith's commercial plant, which is currently sited in Nebraska (EA EST, 2021). Locating the plant in the Midwest enables H_2 to be used for ammonia production. The plant site is assumed to have site characteristics and ambient conditions as presented in Exhibit 2-2 and Exhibit 2-3, consistent with the International Organization for Standardization (ISO) ambient conditions for a generic U.S. Midwest plant location as defined in the "Process Modeling Design Parameters" QGESS document (NETL, 2019a).

Exhibit 2-2. Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size	100 acres
Feedstock Transportation	Pipeline
Water Source	50% municipal and 50% groundwater

Exhibit 2-3. Site ambient conditions

Parameter	Value
Elevation, m (ft)	0 (0)
Barometric Pressure, MPa (psia)	0.101 (14.7)
Average Ambient Dry-Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet-Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air Composition Based on Published Psychrometric Data, mass %	
Nitrogen (N_2)	75.055
Oxygen (O_2)	22.998
Argon (Ar)	1.280
Water (H_2O)	0.616
Carbon Dioxide (CO_2)	0.050
Total	100.00

[A] The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 4.8 °C (8.5 °F) above ambient wet-bulb conditions.

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the feedstock for the plasma pyrolysis case, and its composition is presented in Exhibit 2-4. Natural gas properties are from the 2019 revision of the "Specification for Selected Feedstocks" QGESS document (NETL, 2019b), with the addition of a mercaptan used as a gas odorant (Liss, Thrasher, Steinmetz, Chowdiah, & Attari, 1992).

Exhibit 2-4. Natural gas composition

Component		Volume Percentage
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol[A]	CH_4S	$5.74x10^{-6}$
	Total	100.0
	LHV	**HHV**
kJ/kg (Btu/lb)	47,201 (20,293)	52,295 (22,483)
MJ/scm (Btu/scf)	34.52 (927)	38.25 (1,027)

[A] The sulfur content of natural gas is primarily composed of added mercaptan (methanethiol [CH_4S]) with trace levels of hydrogen sulfide (H_2S) (Liss, Thrasher, Steinmetz, Chowdiah, & Attari, 1992)

Note: Fuel composition is normalized, and heating values are calculated using Aspen

The levelized natural gas price is defined in the "Fuel Prices for Selected Feedstocks in NETL Studies" QGESS document as $4.24/GJ ($4.47/MMBtu) on a higher heating value (HHV) basis, delivered to the Midwest and reported in 2023 U.S. dollars. Fuel costs are levelized over an assumed 30-year plant operational period (NETL, 2025c).

2.4 HYDROGEN PRODUCT SPECIFICATION

The plasma pyrolysis plant produces a H_2 product at the plant gate meeting or exceeding the specification shown in Exhibit 2-5. Consistent in approach with the carbon nanoparticle coproduct, no site-specific, single end-use is considered. Instead, the goal was to consider a H_2 product reflective of current, centralized, fossil-based production facilities and suitable for a wide range of potential energy applications. The maximum impurity concentrations shown in the specification are suitable for ammonia-grade H_2 to avoid catalyst poisoning. The specification also results in a product suitable for the following applications per ISO (ISO, 2019):

- Type I Grade A – Gaseous hydrogen: internal combustion engines for transportation; residential/commercial combustion appliances (e.g., boilers, cookers, and similar applications)
- Type I Grade B – Gaseous hydrogen: industrial fuel for power generation and heat generation except proton-exchange membrane fuel cell applications

Exhibit 2-5. Hydrogen product specification

Characteristic	Specification
H_2 Purity	99.9 vol% min.
CO_2	Total concentration of all oxygen-containing species is 10 ppm max.
CO	
H_2O	
O_2	
H_2S	10 ppb max.
Pressure	6.38 MPag (925 psig)

The modeled H_2 product pressure is maintained at 6.38 MPag (925 psig) to be consistent with a prior NETL H_2 study (Lewis, et al., 2022). The pressure specification was determined based on feedback from a commercial owner/operator of large-scale, centralized merchant H_2 production facilities and a H_2 pipeline transportation and distribution network. The owner/operator advised that pipeline operating pressures vary nominally 5.52–6.21 MPag (800–900 psig), depending on the location within the network. A nominal H_2 production pressure at the plant fence of 6.38 MPag (925 psig) was selected to be greater than the pipeline pressure, with compression occurring within the plant boundary.

A H_2 pressure cost credit is included in the economic analysis to adjust for the lower DOE standard H_2 pressure of 3.0 MPa (435 psia) (U.S. DOE, 2023a). The credit reduced the LCOH by subtracting the additional cost of electricity and cost of compressor equipment associated with compressing to the higher pressure.

2.5 Plant Capacity & Capacity Factor

The plant capacity and capacity factor (CF) are based on a prior proposed expansion of Monolith's Olive Creek I single reactor plant in Hallam, NE by an additional 12 reactors (Mesrobian, 2021). Each plasma reactor is designed to produce approximately 600 kg/hr (1,323 lb/hr) of H_2, bringing the total design capacity of the facility to 7,800 kg/hr (17,196 lb/hr) of H_2 once completed (Mesrobian, 2021).

Under the proposal, Monolith had indicated that all 13 reactors would operate such that the facility achieves 85 percent of its full production capacity on an annual basis. The CF considers the time a reactor is offline for the rebuilding of a reactor torch as well as reactor maintenance procedures that require shutdown and startup approximately once a month (EA EST, 2021).

2.6 Environmental Targets

2.6.1 Air Emissions Targets

Since the study case is located at a greenfield site, permitting a new plant would likely invoke the New Source Review permitting process. The New Source Review process requires the installation of emission control technology meeting either the Best Available Control Technology (BACT) determinations for new sources located in attainment areas, or areas meeting ambient

air quality standards, or the Lowest Achievable Emission Rate technology for sources located in non-attainment areas, or areas not meeting ambient air quality standards.

BACT guidelines are used for the study cases. To meet BACT requirements and minimize the oxides of nitrogen (NOx) emissions from the fired equipment, low NOx burners (LNBs) are included within the plant. The limit for NOx emissions is 2.5 ppmvd at 15 percent oxygen (O_2). Sulfur emissions are controlled without the need for additional process controls because over 98 percent of sulfur in the natural gas feed ends up in the carbon coproduct (EA EST, 2021). Particulate matter (PM) emissions are a larger concern for plasma pyrolysis plants due to the formation of the solid carbon coproduct and its presence in process gas streams. PM emissions are controlled by the use of a main unit filter, dust filters, vent filters, and vacuum systems. No mercury or hydrogen chloride emissions are anticipated; therefore, no controls for these pollutants are necessary.

2.6.2 Effluent Targets

The Environmental Protection Agency (EPA) issued final Effluent Limitation Guidelines (ELG) and standards for the steam electric power generation point source category in May 2024 (U.S. EPA, 2024). The guidelines are assumed to also apply to the plasma pyrolysis plant. The ELG are national technology-based New Source Performance Standards derived from data collected from industry. They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established by this rule are the minimum discharge standards. As ELG are enforced under the National Pollutant Discharge Elimination System (U.S. EPA, n.d.), more stringent water quality-based standards may be established by the local permitting authority; however, these additional requirements were not considered in this report.

The final ELG rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. Non-chemical metal cleaning wastewater was established as a new wastewater category in the updated ELG. However, new limits were not established for this category; therefore, treatment of this stream has not been evaluated in this report. In May 2026, EPA proposed revisions to the final 2024 ELG rule for unmanaged combustion residual leachate (U.S. EPA, 2026). These proposed changes are assumed to not affect the plasma pyrolysis plant.

The landfill of plant byproducts is assumed to be outside the scope of the plant considered in this study; therefore, landfill leachate is not evaluated in this report. Intermittent discharges (e.g., chemical metal cleaning wastewater), low volume waste (e.g., boiler blowdown), and cooling tower blowdown were assumed to be compliant with all applicable regulations with no additional treatment beyond conventional considerations. Under the assumptions established in this section, no additional control technology considerations are required for the case studies regarding compliance with the ELG rule.

2.7 ELECTRICITY

Electricity is a major input to the plant. Electricity input for the plant was assumed to be purchased at $65.2/MWh, according to the “Fuel Prices for Selected Feedstocks in NETL

Studies" (NETL, 2025c). The delivered price of electricity reflects the price paid by an entity to procure utility electricity services and comprises generation, transmission, and distribution components. The price is based on region-level forecasts for the Midcontinent Independent System Operator region for the 2030 delivered industrial electricity reference case, reported in 2023$/MWh (NETL, 2025c). The analysis assumes that there is enough grid capacity to supply all power needed to the plant without major electrical upgrades.

2.8 COPRODUCTS

Three additional coproducts are formed from the plasma pyrolysis process studied: carbon nanoparticles, coke, and steam. This section describes assumptions pertaining to each. It should be noted that coproduct credits or disposal costs could potentially be an additional determining factor in the choice of technology and in the selection of sites for some H_2 producers. A high local value of the product can establish whether design modifications should be considered, or additional capital should be included in the plant to optimize project economics. No such optimization has been performed on the single representation of natural gas plasma pyrolysis presented in this study. However, LCOH sensitivities to changes in the baseline assumptions are provided in Section 3.4.1.

2.8.1 Carbon Nanoparticles

A solid carbon product is produced as a coproduct from the decomposition of hydrocarbon species within the natural gas feedstock (methane, ethane, etc.). The raw form is a carbon nanoparticle that achieves a certain specification, as defined in Monolith patents (United States Patent No. US10808097B2, 2020). The combination of reactor design and optimization with downstream processing and upgrading (e.g., densification) can influence the quality and end use of the carbon coproduct. Options for carbon nanoparticle end uses include carbon black, engineered plastic composites, activated carbon, and anodes for aluminum.

The Monolith facility focuses on producing carbon black, a material used in products such as tires, rubber goods, films, coatings, inks, and plastics (Monolith, 2024). Carbon black is a commodity product that changes price over time and ranged about $1,060–2,020/tonne ($962–1,833/ton) between 2018 and 2024 (Business Analytiq, 2024). In this study, the carbon black price is selected to align with the market price in January 2023, $1,840/tonne ($1,669/ton) (Business Analytiq, 2024). However, since the backend processing is excluded from the scope of the plant, the carbon nanoparticles are assumed to be sold as feedstock to a co-located carbon black production facility at an arbitrary 25 percent of the end market value, or $460/tonne ($417/ton). The impact of the carbon nanoparticle coproduct price on the economic results is explored in multiple sensitivity analysis in Section 3.4.1.

2.8.2 Coke

A small amount of coke is produced in the plasma reactor. No processing and upgrading of coke is included within the scope of the plant. However, the coke is considered a salable product with a value of $61/tonne ($55/ton) (Diab, Fulcheri, Hessel, Rohani, & Frenklach, 2022), reported in 2023$.

2.8.3 Export Steam

Steam generated from excess process heat within the plasma pyrolysis plant may be used internally for power generation or exported to other users. Steam is generated at conditions of 399 °C (750 °F) and 3.10 MPa (450 psia) and is assumed to have no economic value due to its variable marketability (Lewis, et al., 2022).

2.9 PROCESS MODELING APPROACH

The approach for developing the performance results presented in this report included performing steady-state simulations of the H_2 plant configurations at the design capacity using the Aspen Plus® (Aspen) process modeling software. The major plant equipment performance and process limits were based on published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, or best engineering judgment (NETL, 2019a). Mass and energy balance data from the Aspen models were used to size major pieces of equipment, which formed the basis for developing the cost estimates presented.

The modeling of the plasma reactor was simplified due to limited data availability and the complexity of plasma chemistry. Decomposition reactions were modeled in Aspen using the equilibrium reactor block and the 95 percent conversion of methane was achieved by adjusting parameters in the reactor block. The reactions for the conversion of the higher hydrocarbon components were assumed to achieve 100 percent. Since the plasma chemistry was not modeled within Aspen, the power consumption of the plasma torch was adjusted to solve the overall energy balance of the system. The resulting electricity consumption was cross-checked with available data from literature (Diab, Fulcheri, Hessel, Rohani, & Frenklach, 2022). The energy balance also accounted for heat loss of the plasma reactor, which was assumed to be 1 percent of the thermal input of natural gas to the system. The 1 percent loss represents an assumption, and it is acknowledged that the actual system heat loss depends on the specific design of the reactor.

2.10 COSTING ESTIMATING METHODOLOGY

The cost estimating methodology was adapted from the methods presented in the 2024 revision of the “Cost Estimation Methodology for NETL Assessment of Power Plant Performance” QGESS document (NETL, 2025b). All costs are reported in January-2023 dollars. Select portions are repeated in this report for completeness.

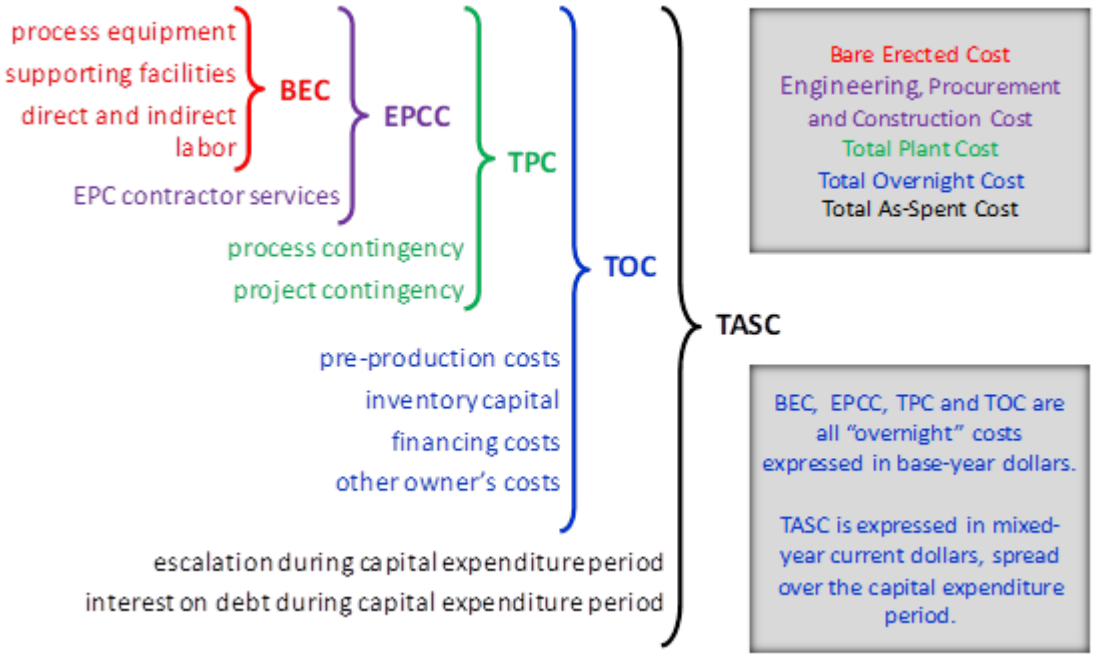
2.10.1 Capital Costs

As illustrated in Exhibit 2-6, there are five levels of capital costs to consider in constructing a plant: bare erected cost (BEC), engineering, procurement, and construction cost (EPCC), total plant cost (TPC), total overnight cost (TOC), and total as-spent cost (TASC).

BEC, EPCC, TPC, and TOC are overnight costs and are expressed in base-year dollars. The base year is the year in which all technology costs are expressed for the comparison of technologies from a standard starting point. TASC is expressed in mixed, current-year dollars over the entire

capital expenditure period, which is assumed in this study to last three years for natural gas-based H_2 plants.

Exhibit 2-6. Capital cost levels



A full, bottom-up estimate for the capital costs was not pursued. Instead, most of the costs were estimated using a scaling approach. This entailed scaling cost estimates from previous NETL studies according to the methodology presented in the 2024 revision of the "Capital Cost Scaling Methodology: Revision 4b Report" QGESS document (NETL, 2025a). For most process equipment, Equation 2-1 is used to scale costs.

$$SC = RC * \left(\frac{SP}{RP}\right)^{EXP} \qquad \textit{Equation 2-1}$$

where:

EXP – exponent

RC – reference cost

RP – reference parameter

SC – scaled cost

SP – scaling parameter

If the scaling algorithm for a piece of process equipment did not exist in the "Capital Cost Scaling Methodology: Revision 4b Report" QGESS document, an appropriate scaling parameter was selected using best engineering judgement and a scaling exponent of 0.6 was selected per the "rule of six-tenths" (Anderson, 2009). Most process equipment capital costs were scaled

from cases of a previous NETL H_2 study (Lewis, et al., 2022). The table in Exhibit 2-7 summarizes from which study case the cost accounts within each equipment category were scaled.

Exhibit 2-7. References for equipment capital cost scaling

Equipment Category	Cost Reference
Feedwater & Miscellaneous Balance-of-Plant Equipment	SMR without CCS (Lewis, et al., 2022)
Pressure Swing Adsorber	
Hydrogen Compressor	
Cooling Water System Equipment	
Improvements to Site Equipment	
Buildings & Structures Equipment	
Raw Gas Coolers (scaled from Syngas Coolers)	ATR with CCS (Lewis, et al., 2022)
Air Blower	
Accessory Electric Plant Equipment	
Instrumentation & Control Equipment	
Thermal Oxidizer (scaled from Fired Heater)	
Process Gas Compressor (scaled from H_2 Compressor)	
Recycle Gas Compressor	
Carbon Filter (scaled from Particulate Removal System)	CG without CCS (Lewis, et al., 2022)

Note: SMR = steam methane reforming; ATR = autothermal reforming; CCS = carbon capture and storage; CG = coal gasification

TPC is the sum of the BEC, the cost of services provided by an engineering, procurement, and construction contractor, process contingencies, and project contingencies. The engineering fees are 20 percent of the BEC for each piece of equipment. Process contingencies depend on the technology status of the individual pieces of equipment, per AACE International (AACE) guidelines and as discussed in the "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" QGESS document (NETL, 2025b). Because the reactor system is a relatively new commercial technology but has been operated at full scale, it was assigned a 20 percent process contingency. The main carbon filter was also assigned a 20 percent process contingency. Instrumentation and control equipment was assigned a 5 percent process contingency due to integration issues with the reactor system. Project contingencies range 15–25 percent of the sum of the BEC, engineering fees, and process contingencies.

TOC is the sum of TPC plus pre-production costs, inventory capital, land, and other owner's costs, which are estimated as 15 percent of the TPC. TASC accounts for the capital escalation and the cost of funding during the capital expenditure period. The nominal TASC multiplier applied to the TOC in the study is 1.173, based on 3 years of construction.

The TASC is multiplied by the fixed charge rate (FCR) to obtain a capital cost on an annual basis. The method used to determine the FCR is found in the "Cost Estimation Methodology for Assessment of Power Plant Performance" QGESS document (NETL, 2025b), which developed

financial factors for various industrial sectors based on market data. The financial parameters for the basic chemicals industry shown in Exhibit 2-8 apply to H_2 production plants and were selected for use in this study.

Exhibit 2-8. Financial assumptions for basic chemicals industry

Financial Parameter	Nominal Value
Fixed Charge Rate	8.82%
TASC/TOC Ratio	1.173
Debt/Equity Ratio	31.35/68.65
Payback Period	30 years
Interest on Debt	5.09%
Return on Equity	8.92%
After Tax Weighted Average Cost of Capital	7.32%
Capital Expenditure Period	3 years
Capital Distribution	1st year – 10% 2nd year – 60% 3rd year – 30%

Based on the study's definition as a concept screening, the capital costs for the plasma pyrolysis case in this analysis carry an uncertainty range of -25 to +50 percent, consistent with AACE Class 5 cost estimates (NETL, 2025b), (AACE International, 2005).

2.10.2 Operation & Maintenance Costs

The operation and maintenance (O&M) costs pertain to yearly costs associated with operating and maintaining the plant over its expected life.

Fixed O&M costs are independent of H_2 production and include annual operating labor, maintenance labor, administrative and support labor, and property taxes and insurance. The plant is assumed to need five operators per shift, who are paid at $45.04/hour with a 30 percent operating labor burden. Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor. Taxes and insurance are included as 2 percent of the TPC.

Variable O&M costs are proportional to H_2 production and include maintenance material, consumables, electricity costs, waste disposal, coproduct credits, and feedstock costs. Maintenance materials were evaluated as a function of capital cost. The consumables for plasma pyrolysis include water, makeup and wastewater treatment chemicals, reactor electrodes, a pressure swing adsorption (PSA) unit adsorbent, and electricity. Most initial fill, makeup rate, and cost data were provided by vendors or determined from correlations developed from data provided by an engineering, procurement, and construction firm. The correlation for the reactor electrodes was based on a 300 kW plasma torch from Sintef that utilizes graphite electrodes (Jensen), assuming replacement once a year at a cost of $4,674/tonne ($4,240/ton) (Fastmarkets, 2022). Waste disposal is only needed for the PSA unit

adsorbent. Coproducts represent a negative cost contribution to the O&M costs for any coproducts sold. Feedstock costs include costs for purchasing natural gas.

2.11 KEY METRICS

A number of performance and cost metrics are used to evaluate and analyze the study results. These metrics are described and defined according to the formulas in this section.

2.11.1 Recovery Efficiency

The carbon recovery efficiency represents the percent of total carbon into the process that is not released to the atmosphere via the plant stack. Carbon is recovered in the process as coke and carbon nanoparticles. This metric is analogous to the carbon capture rate of a plant that captures CO_2.

$$\mathrm{CRE} = \left(1 - \frac{\mathrm{CS}}{\mathrm{TCI}}\right) * 100\%$$

where:

CRE – carbon recovery efficiency, %

CS – mass of carbon in the plant stack, tonne/year

TCI – total mass of carbon into the plant via natural gas, tonne/year

The H_2 recovery efficiency represents the ratio of H_2 produced by the process to the total mass of H_2 into the system.

$$\mathrm{HRE} = \left(\frac{\mathrm{HHP}}{\mathrm{THI}}\right) * 100\%$$

where:

HRE – H_2 recovery efficiency, %

HHP – mass of H_2 in the H_2 product stream, tonne/year

THI – total mass of H_2 into the plant via natural gas, tonne/year

2.11.2 Energy Efficiency

The HHV H_2 energy efficiency is the ratio of thermal energy output in the H_2 product to the major energy inputs to the system, on an HHV basis.

$$\mathrm{HEE\ [HHV]} = \frac{\mathrm{HP} * \mathrm{H_{HHV}}}{\mathrm{EE} + \mathrm{NG} * \mathrm{NG_{HHV}}} * 100\%$$

where:

HEE [HHV] – H_2 energy efficiency on an HHV basis, %

HP – mass of H_2 product stream, lb/hr

H_{HHV} – HHV of H_2 product stream at 25 °C and 1 atm, 60,797 Btu/lb

EE – electrical energy input to the system, Btu/hr

NG – mass of natural gas input to the system, lb/hr

NG_{HHV} – HHV of natural gas input stream at 25 °C and 1 atm, 22,483 Btu/lb

The HHV steam energy efficiency is the ratio of energy output in the steam product to the major energy inputs to the system, on an HHV basis.

$$\text{SEE [HHV]} = \frac{\text{SP} * \text{S}_\text{H}}{\text{EE} + \text{NG} * \text{NG}_\text{HHV}} * 100\%$$

where:

SEE [HHV] – steam energy efficiency on an HHV basis, %

SP – mass of steam product stream, lb/hr

S_H – steam enthalpy at standard conditions (25 °C, 1 atm) to align with HHV, 1,338 Btu/lb

EE – electrical energy input to the system, Btu/hr

NG – mass of natural gas input to the system, lb/hr

NG_{HHV} – HHV of natural gas input stream at 25 °C and 1 atm, 22,483 Btu/lb

The HHV combined energy efficiency is the sum of the H_2 energy efficiency and the steam energy efficiency, or the ratio of major energy outputs to major energy inputs in the system, on an HHV basis. The heating value of carbon products is not considered because it is unlikely they will be sold as energy commodities. However, their energy content is considered in the system energy balance shown in Section 3.2.

$$\text{CEE [HHV]} = \text{HEE [HHV]} + \text{SEE [HHV]}$$

where:

CEE [HHV] – combined energy efficiency on an HHV basis, %

HEE [HHV] – H_2 energy efficiency on an HHV basis, %

SEE [HHV] – steam energy efficiency on an HHV basis, %

The energy efficiency metrics are also reported on an LHV basis by using the LHV for H_2 and natural gas instead of the HHV.

2.11.3 Levelized Cost of Hydrogen

The LCOH is the amount of revenue required per kilogram of H_2 produced during the operational life of the plant to meet all capital and operational costs. The LCOH is calculated according to the following formula:

$$\text{LCOH} = \text{LCC} + \text{LOM} + \text{LFP}$$

where:

LCOH – levelized cost of hydrogen, $/kg

LCC – levelized capital cost determined using the FCR and TASC per kg H_2, $/kg

LOM – levelized annual O&M expenses, fixed and variable, per kg H_2, $/kg

LFP – levelized annual fuel or feedstock price per kg H_2, $/kg

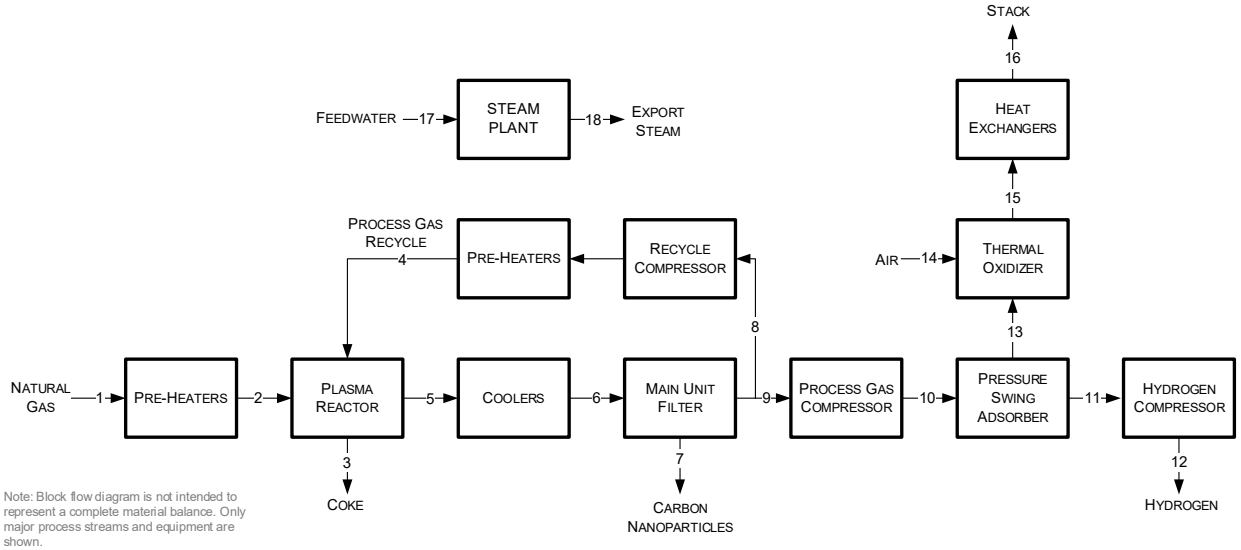
3 RESULTS & DISCUSSION

The process description, mass and energy balances, performance results, cost results, and sensitivity analyses for the plasma pyrolysis case are discussed in sections 3.1, 3.2, 3.3, 3.4, and 0, respectively.

3.1 PROCESS DESCRIPTION

The process configuration is represented by the block flow diagram provided in Exhibit 3-1.

Exhibit 3-1. Block flow diagram for plasma pyrolysis



The associated stream tables show process data provided in Exhibit 3-2. Natural gas [Stream 1] enters the plant at a temperature of 15 °C (59 °F) and a pressure of 0.32 MPa (46.8 psia), which was lowered to meet the pressure requirements of the plasma reactor. The natural gas is pre-heated to 250 °C (482 °F) [Stream 2] with the steam internally generated from the cooling of hot process gas exiting the plasma reactor. Pre-heating is limited so that the cracking of natural gas in the pre-heater is prevented. Pre-heated natural gas then enters the plasma reactor where it is mixed with plasma generated from a fraction of process gas recycle [Stream 4]. The recycled process gas enters the plasma reactor at 650 °C (1,202 °F) and 0.29 MPa (41.8 psia). The plasma reactor operates just above atmospheric pressure and reaches temperatures of up to 2,900 °C (5,252 °F). The following reactions were modeled in the reactor:

$$CH_4 \rightarrow C_{(s)} + 2H_2$$

$$C_2H_6 \rightarrow 2C_{(s)} + 3H_2$$

$$C_3H_8 \rightarrow 3C_{(s)} + 4H_2$$

$$C_4H_{10} \rightarrow 4C_{(s)} + 5H_2$$

Overall methane conversion is about 95 percent (United States Patent No. US10808097B2, 2020), and the remaining reactions are assumed to achieve 100 percent conversion. Side reactions were not modeled. About 1.6 percent of carbon in the natural gas and a small amount of H_2 ends up as coke [Stream 3] produced in the reactor (Diab, Fulcheri, Hessel, Rohani, & Frenklach, 2022), (Blagus, Dankwah, & Sahajwalla, 2012). The reactor products [Stream 5] exit the plasma reactor at a temperature of 1,500 °C (2,732 °F) and are cooled to 250 °C (482 °F) [Stream 6]. Next, the process gas is sent through the main unit filter, which separates out carbon nanoparticles [Stream 7] from the gas, which is primarily H_2. A portion of the process gas is recycled [Stream 8] at a dilution ratio of 5.0. The dilution ratio is defined as the ratio of moles of diluent gas entering the reactor to the total moles of carbon injected (Fulcheri, Rohani, Wyse, Hardman, & Dames, 2023). After the process gas recycle split, the remaining process gas [Stream 9] is compressed from 0.15 MPa (21.8 psia) to 2.76 MPa (400 psia) [Stream 10]. The process gas is then sent through a PSA unit, which generates a purified H_2 product of greater than 99.9 vol% [Stream 11] and meeting the product specification. The purified H_2 is then compressed to a pipeline-ready pressure of 6.48 MPa (939.7 psia) [Stream 12]. The PSA off-gas [Stream 13] is sent to a thermal oxidizer, which combusts the stream using air [Stream 14] as the oxidant. Heat is recovered from the hot flue gas stream [Stream 15] and used to raise steam. The flue gas is then sent to the stack [Stream 16] and released to the atmosphere. Excess heat in the system is used to convert feedwater, which enters at 15 °C, 0.10 MPa (59 °F, 14.7 psia) [Stream 17] to steam at 399 °C, 3.10 MPa (750 °F, 450 psia) [Stream 18] for export.

Exhibit 3-2. Stream table for plasma pyrolysis

	NG Feed 1	NG Pre-Heated 2	Coke Product[C] 3	Recycle Stream #2 4	Process Gas #1[C] 5	Process Gas #2[C] 6	Carbon Product[C] 7	Recycle Stream #1 8	Process Gas #3 9
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.9310	0.9310	0.0000	0.0061	0.0061	0.0061	0.0000	0.0061	0.0061
CH_4S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000
C_2H_6	0.0320	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0070	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0040	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0100	0.0100	0.0000	0.0050	0.0050	0.0050	0.0000	0.0050	0.0050
H_2	0.0000	0.0000	1.0000	0.9810	0.9810	0.9810	0.0000	0.9810	0.9810
H_2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0160	0.0160	0.0000	0.0079	0.0079	0.0079	0.0000	0.0079	0.0079
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	2,292	2,292	0	11,939	16,567	16,567	0	11,939	4,628
V-L Flowrate (kg/hr)	39,707	39,707	1	30,032	41,674	41,674	1	30,032	11,641
Solids Flowrate (kg/hr)	0	0	459	0	27,605	27,605	27,605	0	0
Temperature (°C)	15	250	1,500	650	1,500	250	250	250	38
Pressure (MPa, abs)	0.32	0.29	0.22	0.29	0.22	0.18	0.18	0.18	0.15
Steam Table Enthalpy (kJ/kg)[A]	27	606	---	7,645	---	---	---	2,908	433
Aspen Plus Enthalpy (kJ/kg)[B]	-4,482	-3,903	4,029	6,404	11,969	1,093	228	1,667	-808
Density (kg/m^3)	2.4	1.1	0.0	0.1	0.0	0.1	2.1	0.1	0.1
V-L Molecular Weight	17.328	17.328	2.016	2.515	2.516	2.516	48.109	2.515	2.515
V-L Flowrate (lb_{mol}/hr)	5,052	5,052	1	26,321	36,523	36,523	0	26,321	10,203
V-L Flowrate (lb/hr)	87,539	87,539	1	66,209	91,875	91,875	1	66,209	25,664
Solids Flowrate (lb/hr)	0	0	1,013	0	60,859	60,859	60,859	0	0
Temperature (°F)	59	482	2,732	1,202	2,732	482	482	482	100
Pressure (psia)	46.8	41.8	31.8	41.8	31.8	26.8	26.8	26.8	21.8
Steam Table Enthalpy (Btu/lb)[A]	12	261	---	3,287	---	---	---	1,250	186
Aspen Plus Enthalpy (Btu/lb)[B]	-1,927	-1,678	1,732	2,753	5,146	470	98	716	-348
Density (lb/ft^3)	0.147	0.072	0.002	0.006	0.002	0.007	0.129	0.007	0.009

[A] Steam Table reference conditions are 32.02 °F and 0.089 psia

[B] Aspen Plus thermodynamic reference state is the component's constituent elements in an ideal gas state at 25 °C and 1 atm

[C] Streams 3, 5, 6, and 7 include solid phase carbon particles. Properties of these streams (e.g., density) may be inaccurate due to not accounting for all solid phase physical properties in this analysis.

Exhibit 3-2. Stream table for plasma pyrolysis (cont'd)

	Process Gas #4 10	H_2 Low Pressure 11	H_2 High Pressure 12	Offgas 13	Air Feed 14	Fuel Gas 15	Stack 16	Water Feed 17	Export Steam 18
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0092	0.0077	0.0077	0.0000	0.0000
CH_4	0.0061	0.0000	0.0000	0.0367	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0050	0.0000	0.0000	0.0298	0.0003	0.0205	0.0205	0.0000	0.0000
H_2	0.9810	0.9998	0.9998	0.8866	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0000	0.0000	0.0000	0.0099	0.2994	0.2994	1.0000	1.0000
N_2	0.0079	0.0002	0.0002	0.0468	0.7732	0.6568	0.6568	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2074	0.0157	0.0157	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	4,628	3,860	3,860	768	2,105	2,533	2,533	12,118	12,118
V-L Flowrate (kg/hr)	11,641	7,800	7,800	3,841	60,746	64,588	64,588	218,315	218,315
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0
Temperature (°C)	38	38	30	38	15	628	121	15	399
Pressure (MPa, abs)	2.76	2.69	6.48	0.14	0.10	0.11	0.10	0.10	3.10
Steam Table Enthalpy (kJ/kg)[A]	439	546	447	221	30	1,325	674	63	3,226
Aspen Plus Enthalpy (kJ/kg)[B]	-803	190	91	-2,819	-98	-2,388	-3,039	-15,917	-12,754
Density (kg/m^3)	2.6	2.1	5.0	0.3	1.2	0.4	0.8	999.1	10.4
V-L Molecular Weight	2.515	2.021	2.021	5.001	28.857	25.502	25.502	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	10,203	8,509	8,509	1,693	4,641	5,584	5,584	26,716	26,716
V-L Flowrate (lb/hr)	25,664	17,196	17,196	8,468	133,923	142,391	142,391	481,301	481,301
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0
Temperature (°F)	100	100	86	100	59	1,162	250	59	750
Pressure (psia)	400.0	390.0	939.7	20.0	14.7	16.0	14.7	14.7	450.0
Steam Table Enthalpy (Btu/lb)[A]	189	235	192	95	13	570	290	27	1,387
Aspen Plus Enthalpy (Btu/lb)[B]	-345	82	39	-1,212	-42	-1,027	-1,307	-6,843	-5,483
Density (lb/ft^3)	0.165	0.130	0.314	0.017	0.076	0.023	0.049	62.374	0.652

[A] Steam Table reference conditions are 32.02 °F and 0.089 psia

[B] Aspen Plus thermodynamic reference state is the component's constituent elements in an ideal gas state at 25 °C and 1 atm

3.2 MASS & ENERGY BALANCES

The carbon mass balance for the plasma pyrolysis case is shown in Exhibit 3-3. The primary source of carbon in the process is from the natural gas feed. Over 96 percent of the carbon in ends up in the carbon nanoparticles product.

Exhibit 3-3. Carbon balance for plasma pyrolysis

Carbon In kg/hr (lb/hr)		Carbon Out kg/hr (lb/hr)	
Natural Gas	28,680 (63,228)	Stack Gas	622 (1,372)
Air (CO_2)	8 (18)	Hydrogen	1 (2)
		Coke	459 (1,013)
		Carbon Nanoparticles	27,605 (60,860)
TOTAL	**28,688 (63,246)**	**TOTAL**	**28,688 (63,246)**

The sulfur mass balance for the plasma pyrolysis case is shown in Exhibit 3-4. The primary source of sulfur in the process is from the natural gas feed. Over 98 percent of the sulfur in ends up in the carbon nanoparticles product (EA EST, 2021).

Exhibit 3-4. Sulfur balance for plasma pyrolysis

Sulfur In kg/hr (lb/hr)		Sulfur Out kg/hr (lb/hr)	
Natural Gas	0.42 (0.93)	Stack Gas	0.01 (0.02)
		Carbon Nanoparticles	0.41 (0.91)
TOTAL	**0.4 (0.9)**	**TOTAL**	**0.4 (0.9)**

The energy balance for the plasma pyrolysis case is shown in Exhibit 3-5. The major energy inputs are the natural gas feed and auxiliary power. The major energy outputs are the H_2 product, carbon nanoparticles product, and export steam.

Exhibit 3-5. Energy balance for plasma pyrolysis

	HHV	Sensible + Latent	Power	Total
Energy In GJ/hr (MMBtu/hr)				
Natural Gas	2,076 (1,968)	1.4 (1.3)	–	2,078 (1,969)
Air	–	1.8 (1.7)	–	1.8 (1.7)
Raw Water Makeup	–	16 (15)	–	16 (15)
Auxiliary Power	–	–	772 (731)	772 (731)
TOTAL	**2,076 (1,968)**	**19 (18)**	**772 (731)**	**2,867 (2,717)**
Energy Out GJ/hr (MMBtu/hr)				
Hydrogen	1,103 (1,045)	3.5 (3.3)	–	1,107 (1,049)
Carbon Nanoparticles	904 (857)	6.8 (6.4)	–	911 (864)
Coke	15 (14)	1.9 (1.8)	–	17 (16)
Export Steam	–	704 (668)	–	704 (668)
Stack Gas	–	44 (41)	–	44 (41)
Heat Loss & Design Allowances	–	–	21 (20)	21 (20)
Cooling Tower Load[A]	–	63 (60)	–	63 (60)
Process Water Discharge	–	0.8 (0.8)	–	0.8 (0.8)
TOTAL	**2,023 (1,917)**	**824 (781)**	**21 (20)**	**2,867 (2,717)**

[A] Includes compressor intercooling and miscellaneous gas cooling

The water balance for the plasma pyrolysis case is shown in Exhibit 3-6. Water demand represents the total amount of water required for a particular process, and any internal recycle water is applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a municipal source for use in the plant. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source. The primary source of water demand and consumption is for export steam, making up around 91 percent of raw water consumption for the process. Only a small amount of water is discharged from the cooling tower.

Exhibit 3-6. Water balance for plasma pyrolysis

Water Use m^3/min (gpm)	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
Export Steam	3.6 (963)	–	3.6 (963)	–	3.6 (963)
Cooling Tower	0.5 (127)	–	0.5 (127)	0.1 (29)	0.4 (98)
TOTAL	**4.1 (1,090)**	**–**	**4.1 (1,090)**	**0.1 (29)**	**4.0 (1,061)**

3.3 PERFORMANCE RESULTS

The performance results are summarized in Exhibit 3-7. The definitions of efficiency values can be found in Section 2.10.

Exhibit 3-7. Performance summary for plasma pyrolysis

Performance Summary	
Hydrogen Production, kg/hr (lb/hr)	7,800 (17,196)
Carbon Nanoparticles Production, kg/hr (lb/hr)	27,606 (60,861)
Coke Production, kg/hr (lb/hr)	460 (1,014)
Steam Production, kg/hr (lb/hr)	218,315 (481,301)
Natural Gas Consumption, kg/hr (lb/hr)	39,707 (87,539)
Gross Power, MWe	0
Total Auxiliaries, MWe	214
Net Power, MWe	-214
Hydrogen Recovery Efficiency, %	83.9
Carbon Recovery Efficiency, %	97.8
Combined Energy Efficiency (HHV), %	62.6
Hydrogen Energy Efficiency (HHV), %	*38.7*
Steam Energy Efficiency (HHV), %	*23.9*
Combined Energy Efficiency (LHV), %	60.9
Hydrogen Energy Efficiency (LHV), %	*35.3*
Steam Energy Efficiency (LHV), %	*25.7*
Total Auxiliaries:Hydrogen Ratio, kWh/kg H_2 (kWh/lb H_2)	27 (12)
Raw Water Consumption, L/kg H_2 (gal/lb H_2)	31 (3.7)

The auxiliary load for the plasma pyrolysis case is broken down in Exhibit 3-8. The total auxiliaries of the plant sum to 214 MWe. Since the process does not include power generation, the net power of the plant is -214 MWe. As anticipated, the largest contributor to the plant power is the plasma reactor, consuming 180 MW and contributing to 84 percent of the plant auxiliaries. The other major auxiliary loads in the process are compressors.

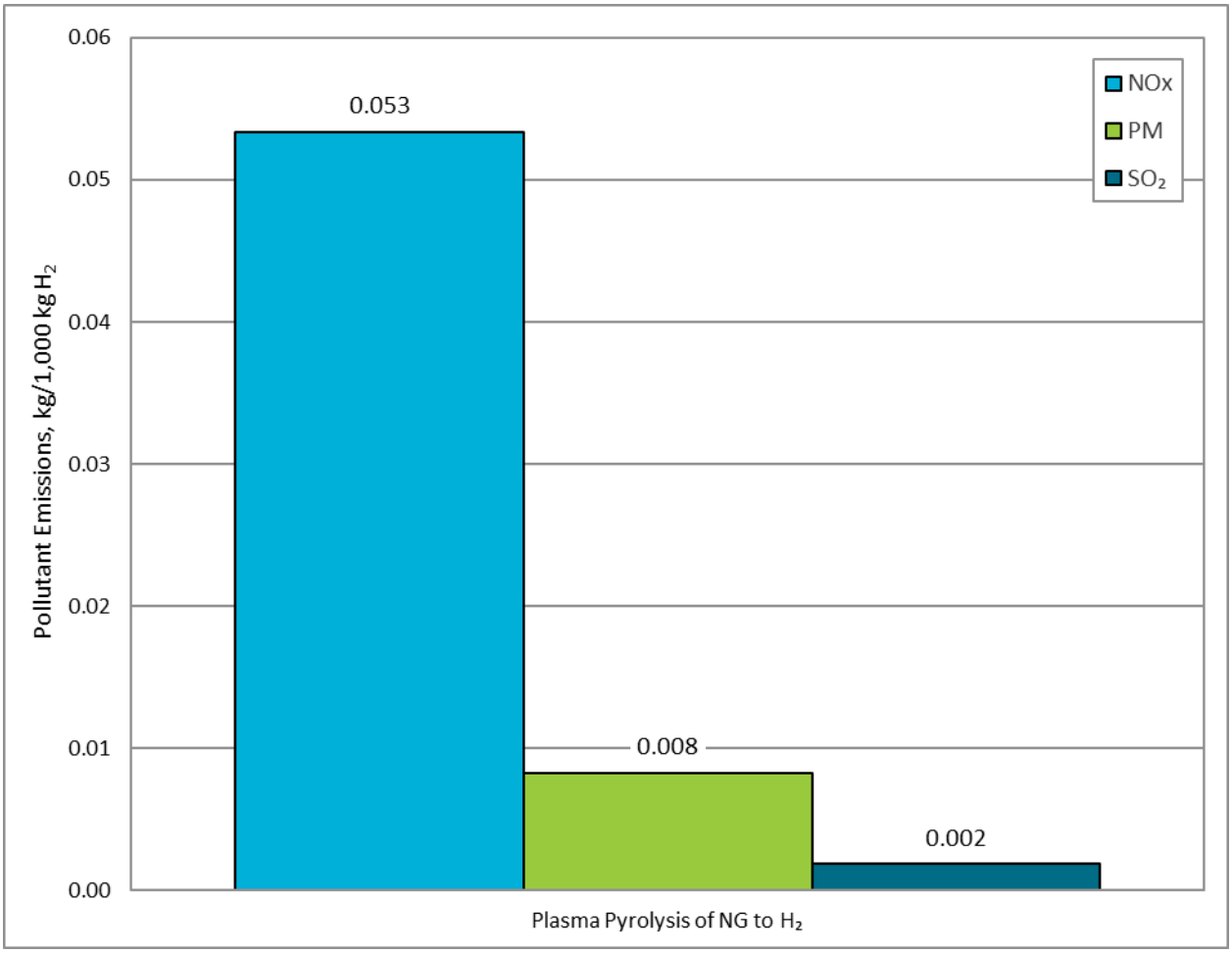
Exhibit 3-8. Power summary for plasma pyrolysis

Power Summary	
Gross Power, MWe	**0**
Air Blower, kWe	170
Circulating Water Pumps, kWe	130
Cooling Tower Fans, kWe	60
Feedwater Pumps, kWe	250
Ground Water Pumps, kWe	100
Hydrogen Compressor, kWe	3,390
Miscellaneous Balance of Plant,[A] kWe	4,790
Plasma Reactor, kWe	179,890
Pressure Swing Adsorption Unit, kWe	1,100
Process Gas Compressor, kWe	14,410
Recycle Gas Compressor, kWe	8,850
Transformer Losses, kWe	1,230
Total Auxiliaries, MWe	**214**
Net Power, MWe	**-214**

[A] Includes plant control systems; lighting; heating, ventilation, and air conditioning; and miscellaneous low voltage loads

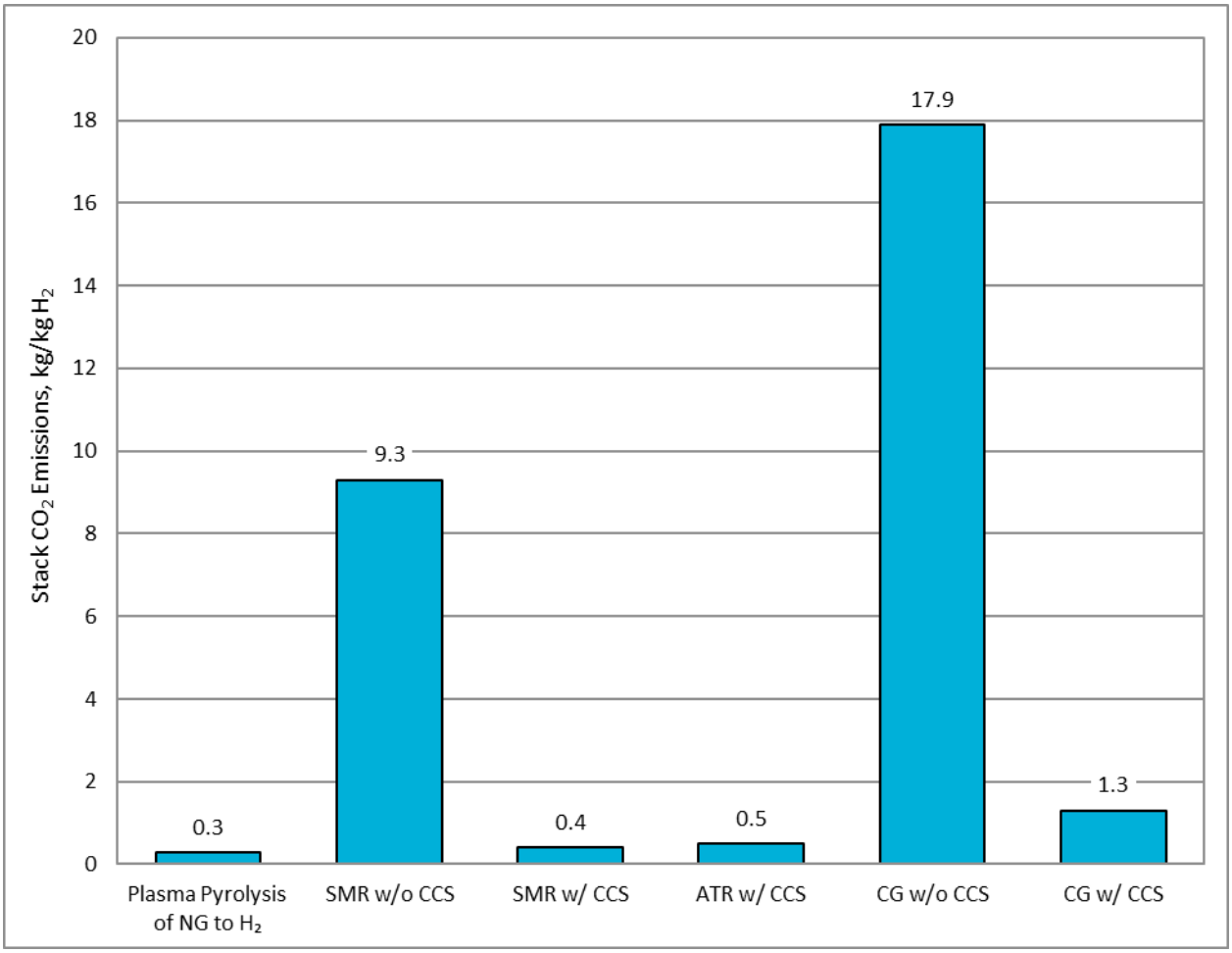
The pollutant emissions for the plasma pyrolysis case are summarized in Exhibit 3-9. Sulfur dioxide (SO_2) emissions are relatively low because most of the sulfur in the natural gas feed ends up in the carbon nanoparticles (EA EST, 2021). NOx emissions are limited by the use of LNBs and minimal amount of fuel combusted within the thermal oxidizer in the process. Note that the PM emissions shown are only representative of those formed via combustion and do not account for additional emissions expected from carbon nanoparticle handling outside of the plant boundary.

Exhibit 3-9. Pollutant emissions for plasma pyrolysis



The plant stack CO_2 emissions for the plasma pyrolysis case are compared to the plant stack CO_2 emissions expected from other fossil-based H_2 production technologies in Exhibit 3-10 (Lewis, et al., 2022). The graph shows that the plasma pyrolysis case produces a quantity of stack CO_2 on par with, if not slightly lower than, other natural gas-to-H_2 technologies with CCS such as SMR and ATR.

Exhibit 3-10. Stack CO_2 emissions for plasma pyrolysis compared to fossil-based H_2 production technologies



3.4 COST RESULTS

Exhibit 3-11 shows a detailed breakdown of the capital costs, including equipment cost, material cost, direct and indirect labor costs, BEC, engineering home office fees, process contingencies, project contingencies, and TPC. The table shows costs by process equipment and summed by process area cost accounts. The total BEC for the plasma pyrolysis case is $366 MM and the TPC is $590 MM. The largest contributors to capital costs are the reactor and accessories cost account, making up more than half of the BEC, or around $212 MM.

Exhibit 3-11. Total plant cost details for plasma pyrolysis

		Case:	Plasma Pyrolysis of Natural Gas to Hydrogen					Estimate Type:		Conceptual	
	Plant Size (kg H_2/day):	187,200						Cost Base:		Jan-2023	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Engineering, Construction Management, Home Office & Fees	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/[kg H_2/day]
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$25	$49	$107	$84	$265	$53	$0	$48	$366	$2
3.2	Water Makeup & Pretreating	$2,499	$241	$1,104	$0	$3,843	$769	$0	$922	$5,534	$30
3.3	Other Feedwater Subsystems	$734	$232	$178	$0	$1,144	$229	$0	$206	$1,578	$8
3.4	Service Water Systems	$758	$1,395	$3,653	$0	$5,807	$1,161	$0	$1,394	$8,362	$45
3.5	Other Boiler Plant Systems	$218	$80	$161	$0	$459	$92	$0	$83	$634	$3
3.6	Natural Gas Pipeline & Start-Up System	$9,031	$347	$211	$0	$9,589	$1,918	$0	$1,726	$13,232	$71
3.7	Waste Water Treatment Equipment	$730	$0	$349	$0	$1,078	$216	$0	$259	$1,552	$8
3.9	Miscellaneous Plant Equipment	$12,363	$1,563	$4,897	$0	$18,823	$3,765	$0	$4,517	$27,105	$145
	Subtotal	**$26,358**	**$3,906**	**$10,660**	**$84**	**$41,008**	**$8,202**	**$0**	**$9,154**	**$58,364**	**$312**
4	Reactor & Accessories										
4.1	Reactor & Accessories	$81,406	$7,543	$69,129	$53,915	$211,993	$42,399	$42,399	$74,140	$370,930	$1,981
	Subtotal	**$81,406**	**$7,543**	**$69,129**	**$53,915**	**$211,993**	**$42,399**	**$42,399**	**$74,140**	**$370,930**	**$1,981**
6	Process Gas Cleanup										
6.3	Process Gas Compressor	$9,396	$817	$768	$599	$11,580	$2,316	$0	$2,779	$16,675	$89
6.4	Carbon Filter	$1,677	$0	$558	$0	$2,234	$447	$447	$469	$3,598	$19
	Subtotal	**$11,072**	**$817**	**$1,326**	**$599**	**$13,814**	**$2,763**	**$447**	**$3,248**	**$20,272**	**$108**
7	Hydrogen Production										
7.1	Pressure Swing Adsorber	$9,766	$14	$345	$269	$10,393	$2,079	$0	$2,494	$14,966	$80
7.2	Hydrogen Compressor	$5,190	$138	$299	$233	$5,861	$1,172	$0	$1,407	$8,439	$45
	Subtotal	**$14,956**	**$152**	**$643**	**$502**	**$16,253**	**$3,251**	**$0**	**$3,901**	**$23,405**	**$125**
8	Thermal Oxidizer, Ductwork, & Stack										
8.1	Thermal Oxidizer	$5,027	$296	$1,207	$942	$7,472	$1,494	$0	$1,793	$10,759	$57
8.2	Thermal Oxidizer Accessories	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1
8.3	Ductwork	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1
8.4	Stack	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1	w/ 8.1
	Subtotal	**$5,027**	**$296**	**$1,207**	**$942**	**$7,472**	**$1,494**	**$0**	**$1,793**	**$10,759**	**$57**
9	Cooling Water System										
9.1	Cooling Towers	$1,141	$0	$273	$0	$1,414	$283	$0	$255	$1,951	$10
9.2	Circulating Water Pumps	$152	$0	$7	$0	$159	$32	$0	$29	$219	$1
9.3	Circulating Water System Auxiliaries	$2,194	$0	$226	$0	$2,419	$484	$0	$435	$3,338	$18
9.4	Circulating Water Piping	$0	$462	$338	$0	$800	$160	$0	$144	$1,104	$6
9.5	Makeup Water System	$264	$0	$264	$0	$528	$106	$0	$95	$729	$4
9.6	Component Cooling Water System	$65	$0	$42	$0	$107	$21	$0	$19	$148	$1
9.7	Circulating Water System Foundations	$0	$107	$143	$0	$250	$50	$0	$60	$360	$2

		Case:	Plasma Pyrolysis of Natural Gas to Hydrogen						Estimate Type:		Conceptual	
	Plant Size (kg H_2/day):	187,200							Cost Base:		Jan-2023	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Engineering, Construction Management, Home Office & Fees	Contingencies		Total Plant Cost		
				Direct	Indirect			Process	Project	$/1,000	$/[kg H_2/day]	
	Subtotal	**$3,816**	**$568**	**$1,293**	**$0**	**$5,677**	**$1,135**	**$0**	**$1,037**	**$7,849**	**$42**	
	11					**Accessory Electric Plant**						
11.2	Station Service Equipment	$0	$2,250	$175	$137	$2,562	$512	$0	$461	$3,535	$19	
11.3	Switchgear & Motor Control	$0	$1,201	$303	$237	$1,741	$348	$0	$313	$2,403	$13	
11.4	Conduit & Cable Tray	$0	$561	$820	$640	$2,021	$404	$0	$364	$2,789	$15	
11.5	Wire & Cable	$0	$1,322	$753	$587	$2,662	$532	$0	$479	$3,673	$20	
11.6	Protective Equipment	$0	$885	$1,266	$987	$3,138	$628	$0	$565	$4,330	$23	
11.8	Main Power Transformers	$0	$314	$120	$93	$528	$106	$0	$95	$728	$4	
11.9	Electrical Foundations	$0	$15	$36	$28	$80	$16	$0	$19	$115	$1	
	Subtotal	**$0**	**$6,548**	**$3,474**	**$2,709**	**$12,731**	**$2,546**	**$0**	**$2,296**	**$17,574**	**$94**	
	12					**Instrumentation & Control**						
12.6	Control Boards, Panels & Racks	$0	$661	$62	$49	$772	$154	$39	$145	$1,110	$6	
12.7	Distributed Control System Equipment	$18,231	$0	$439	$0	$18,671	$3,734	$934	$3,501	$26,839	$143	
12.8	Instrument Wiring & Tubing	$0	$463	$642	$500	$1,605	$321	$80	$301	$2,307	$12	
12.9	Other Instrumentation & Controls Equipment	$0	$2,863	$606	$473	$3,941	$788	$197	$739	$5,666	$30	
	Subtotal	**$18,231**	**$3,987**	**$1,750**	**$1,022**	**$24,989**	**$4,998**	**$1,249**	**$4,685**	**$35,922**	**$192**	
	13					**Improvements to Site**						
13.1	Site Preparation	$0	$915	$15,705	$0	$16,620	$3,324	$0	$3,989	$23,932	$128	
13.2	Site Improvements	$0	$364	$1,170	$913	$2,447	$489	$0	$587	$3,523	$19	
13.3	Site Facilities	$2,871	$0	$2,395	$0	$5,266	$1,053	$0	$1,264	$7,583	$41	
	Subtotal	**$2,871**	**$1,279**	**$19,271**	**$913**	**$24,333**	**$4,867**	**$0**	**$5,840**	**$35,039**	**$187**	
	14					**Buildings & Structures**						
14.2	Interconnecting Pipe	$0	$391	$737	$575	$1,702	$340	$0	$306	$2,349	$13	
14.4	Administration Building	$0	$358	$196	$0	$554	$111	$0	$100	$764	$4	
14.5	Circulation Water Pumphouse	$0	$6	$2	$0	$8	$2	$0	$1	$11	$0	
14.6	Water Treatment Buildings	$0	$216	$159	$0	$375	$75	$0	$67	$517	$3	
14.7	Machine Shop	$0	$534	$276	$0	$810	$162	$0	$146	$1,118	$6	
14.8	Warehouse	$0	$417	$204	$0	$621	$124	$0	$112	$857	$5	
14.9	Structural Steel Pipe Racks	$0	$1,113	$517	$403	$2,034	$407	$0	$366	$2,807	$15	
14.10	Waste Treating Building & Structures	$0	$490	$706	$0	$1,196	$239	$0	$215	$1,650	$9	
	Subtotal	**$0**	**$3,524**	**$2,797**	**$978**	**$7,298**	**$1,460**	**$0**	**$1,314**	**$10,072**	**$54**	
	Total	**$163,738**	**$28,619**	**$111,549**	**$61,663**	**$365,568**	**$73,114**	**$44,095**	**$107,409**	**$590,186**	**$3,153**	

Exhibit 3-12 shows the owner's costs for the plasma pyrolysis case.

Exhibit 3-12. Owner's costs for plasma pyrolysis

Description	$/1,000	$/[kg H_2/day]
Pre-Production Costs		
6 Months All Labor	$4,406	$24
1 Month Maintenance Materials	$660	$4
1 Month Non-Fuel Consumables	$10,496	$56
1 Month Waste Disposal	$8	$0
25% of 1 Months Natural Gas Cost at 100% CF	$2,259	$12
2% of TPC	$11,804	$63
Total	**$29,632**	**$158**
Inventory Capital		
60-Day Supply of Consumables at 100% CF	$94	$1
0.5% of TPC (spare parts)	$2,951	$16
Total	**$3,045**	**$16**
Other Costs		
Initial Cost for Catalyst and Chemicals	$3,256	$17
Land	$600	$3
Other Owner's Costs	$88,528	$473
Financing Costs	$15,935	$85
Total Overnight Costs (TOC)	**$731,182**	**$3,906**
TASC Multiplier (IOU, 33 year)	1.224	
Total As-Spent Cost (TASC)	**$895,161**	**$4,782**

Exhibit 3-13 shows the breakdown of TOC and TASC for the plasma pyrolysis case. The owner's costs make up 19 percent of TOC. The project contingency makes up 15 percent and process contingency 6 percent of TOC.

Exhibit 3-13. Total overnight and total as-spent costs for plasma pyrolysis

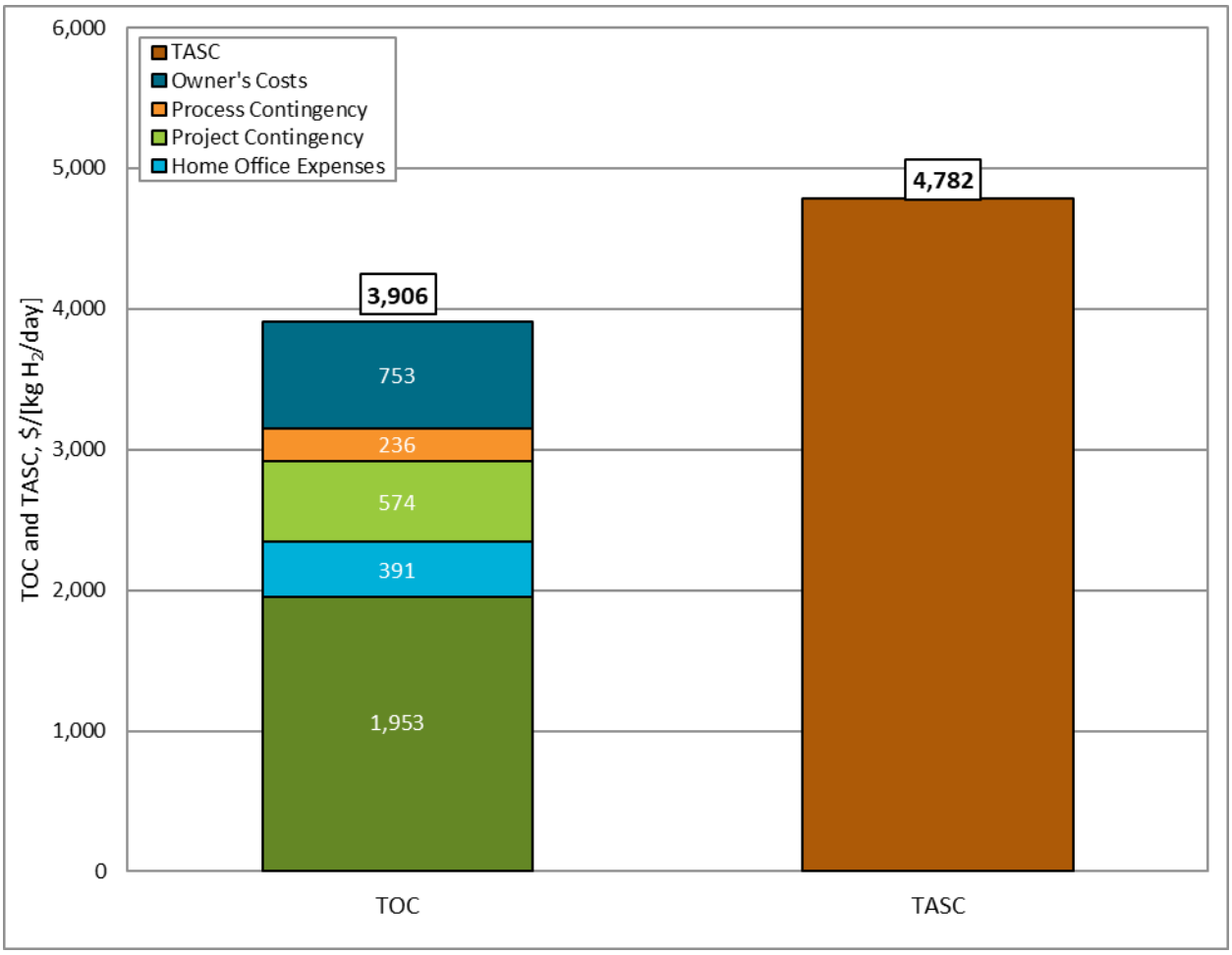


Exhibit 3-14 shows the initial and annual O&M costs for the plasma pyrolysis case. The largest contributor to the operating costs is the purchase of electricity, which accounts for \$1.79/kg H_2 of the LCOH. The next largest contributor is the purchase of natural gas feedstock, which accounts for \$1.13/kg H_2. Coproduct credits are also shown in Exhibit 3-14, and the sale of carbon nanoparticles at \$460/tonne (\$417/ton) reduces the LCOH by \$1.63/kg H_2.

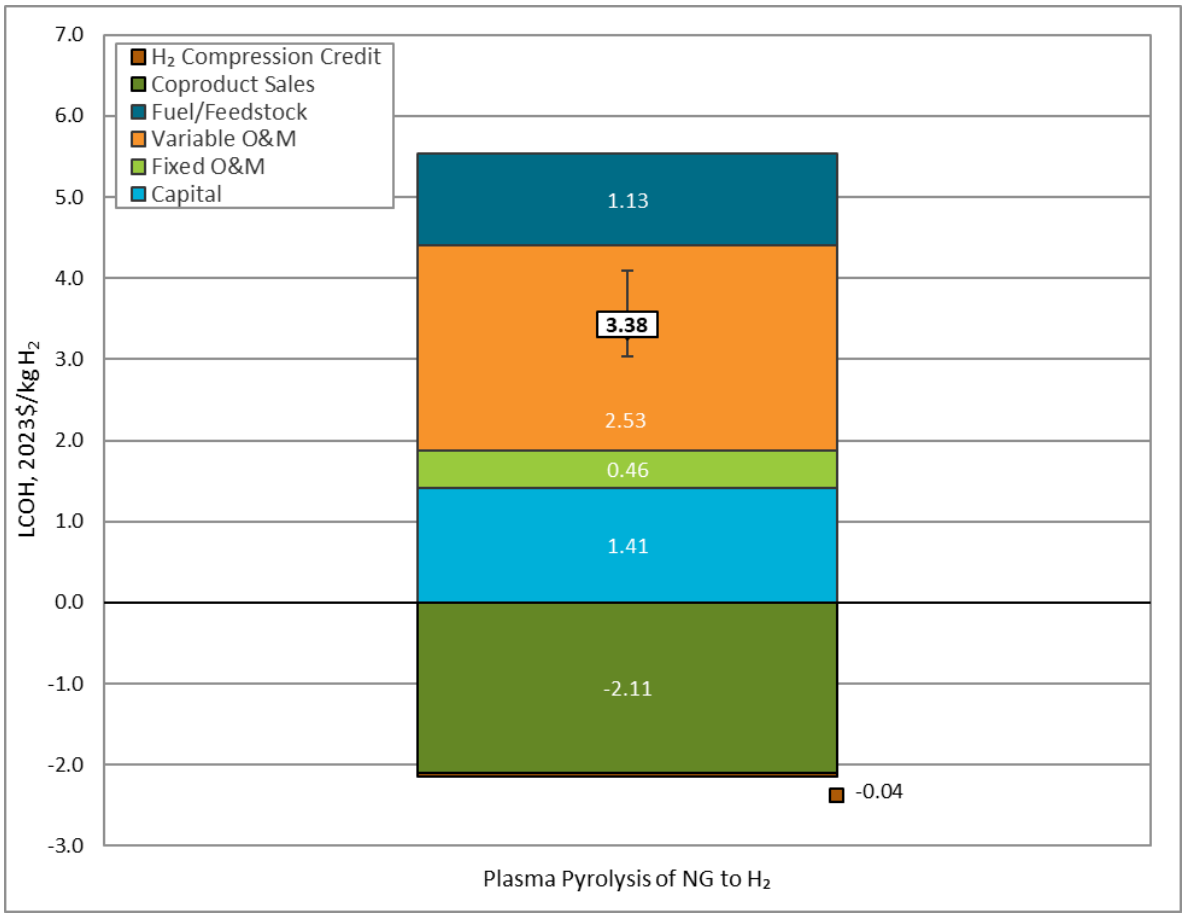
Exhibit 3-14. Initial and annual operation and maintenance costs for plasma pyrolysis

Case:	Plasma Pyrolysis of Natural Gas to Hydrogen				Cost Base:	Jan-2023
Plant Size (kg H_2/day):	187,200				Capacity Factor (%):	85
Operation & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	2.0	
Labor Overhead Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**5.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/[kg H_2/day])**
Annual Operating Labor:					$2,564,552	$13.70
Maintenance Labor:					$4,485,416	$23.96
Administrative & Support Labor:					$1,762,492	$9.42
Property Taxes and Insurance:					$11,803,725	$2.20
Total:					**$20,616,185**	**$49.28**
Variable Operating Costs						
					($)	**($/kg H_2)**
Maintenance Material:					$6,728,123	$0.1158
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (gal/1000):	0	1,569	$2.30	$0	$1,119,676	$0.0193
Makeup and Wastewater Treatment Chemicals (ton):	0	2.3	$660	$0	$478,551	$0.0082
Reactor Electrode (ton):	311	1.0	$4,240	$1,318,345	$1,318,345	$0.0227
PSA Unit Adsorbent (ft^3):	9,976	1.4	$194	$1,937,394	$82,339	$0.0014
Electricity (MWh):	0	5,145	$65.2	$0	$104,056,214	$1.7916
Subtotal:				**$3,255,739**	**$107,055,125**	**$1.8433**
Waste Disposal						
PSA Unit Adsorbent (ft^3):	0	1.4	$1.84	$0	$782	$0.0000
Subtotal:				**$0**	**$782**	**$0.0000**
Total:				**$3,255,739**	**$113,784,031**	**$0.3275**
Coproduct Credits						
					($)	**($/kg H_2)**
Steam (ton):	0	5,776	$0	$0	$0	$0.0000
Carbon Nanoparticles (ton):	0	730	$417	$0	$94,554,780	$1.6280
Coke (ton):	0	12	$55	$0	$208,370	$0.0036
Total:				**$0**	**$94,763,150**	**$1.6316**
Feedstock Costs						
Natural Gas (MMBtu):	0	47,235	$4.47	$0	$65,506,085	$1.1279
Total:				**$0**	**$65,506,085**	**$1.1279**

3.4.1 Baseline LCOH and Sensitivity Analysis

The LCOH for the plasma pyrolysis case is \$3.38/kg H_2, and the breakdown is shown in Exhibit 3-15. The error bars represent the AACE Class 5 uncertainty range of -25 to +50 percent applied to the capital cost component of the LCOH. The largest contributor to the cost, at 46 percent, is the variable O&M, which primarily includes electricity purchase. The second largest contributor, at 26 percent, is the capital cost. The sale of coproducts, primarily carbon nanoparticles, reduces the LCOH by 38 percent.

Exhibit 3-15. Breakdown of LCOH for plasma pyrolysis



Five graphs depicting the LCOH sensitivities to key study parameters are shown in Exhibit 3-16. If the export steam is sold at an expected sales price of \$9/tonne (\$8/ton), instead of the baseline no cost assumption, the LCOH can be lowered by about 9 percent to \$3.06/kg H_2. The CF is not a major factor for cost reduction, as increasing it toward 95 percent CF offers minimal cost reduction; however, a low CF can increase the LCOH significantly. The carbon nanoparticle price has a major impact on the LCOH. If the carbon nanoparticles are able to be sold at the full carbon black market price of \$1,870/tonne (\$1,669/ton), the LCOH is reduced to around -\$2.92/kg H_2, which indicates the revenue received from carbon black exceeds all capital and operating expenses of the plant. Note that this sensitivity does not account for additional capital and operating costs needed to achieve a specific carbon specification. This shows that

selling high-value carbon coproducts play a critical role in the system economics. The LCOH is also highly sensitive to the electricity price. The natural gas price has a moderate impact on the LCOH; at the lower extreme of $0/MMBtu, the LCOH is $2.25/kg H_2.

Exhibit 3-16. LCOH sensitivity to export steam sales price (top left), capacity factor (top right), carbon coproduct price (center), electricity price (bottom left), and natural gas price (bottom right)

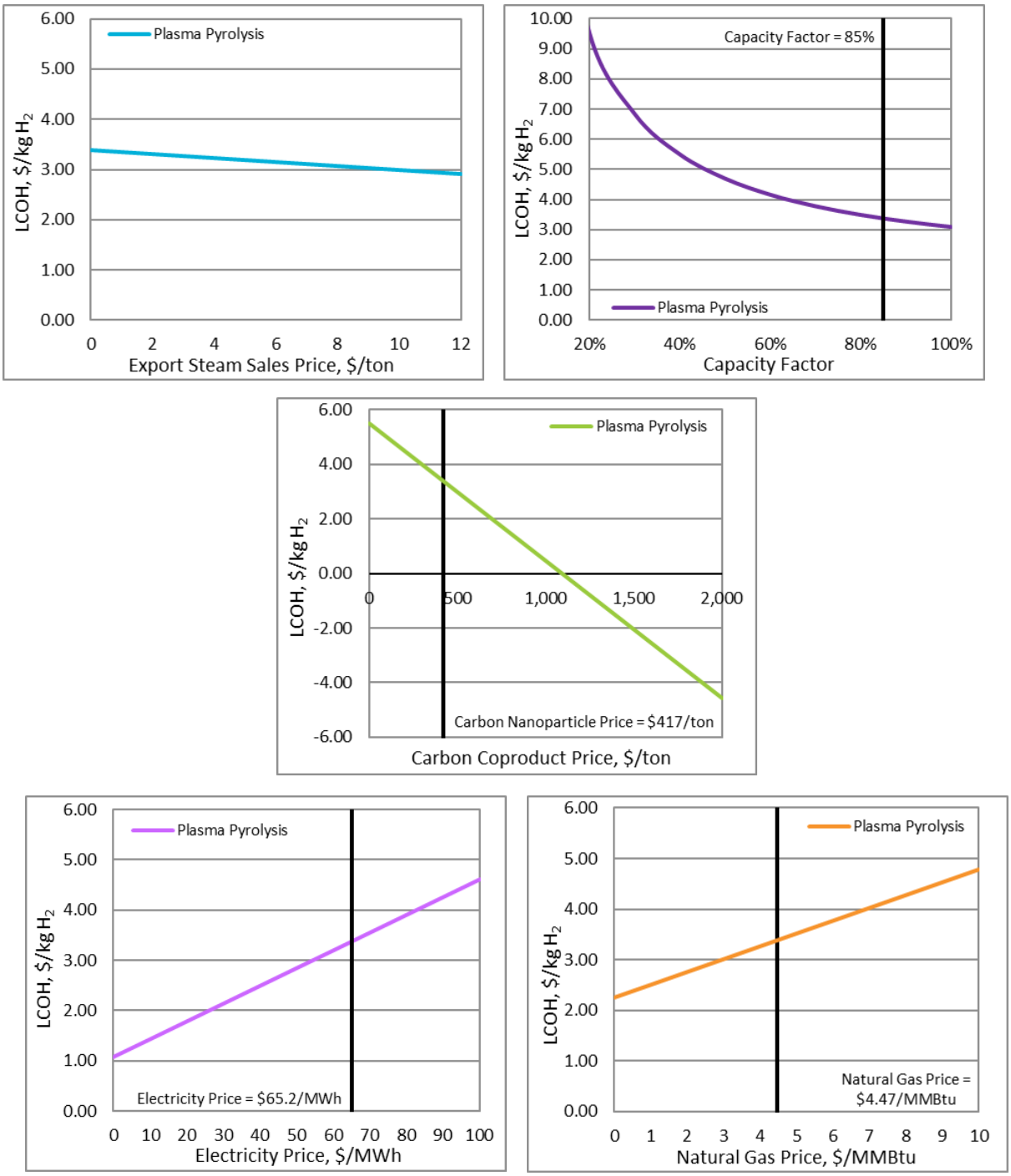


Exhibit 3-17 shows a tornado plot that represents relative sensitivities of key process analysis parameters. Each parameter was varied from low to high boundaries as set in the individual sensitivity graphs, with resulting impact to the LCOH shown on the tornado plot. The carbon coproduct price has the greatest potential to reduce the LCOH, if high-value carbon products are sold. The CF has the greatest potential to increase the LCOH, if the plant operates at very low CFs. Export steam has the least impact on the LCOH within the range examined.

Exhibit 3-17. Tornado plot showing relative sensitivities of key process analysis parameters

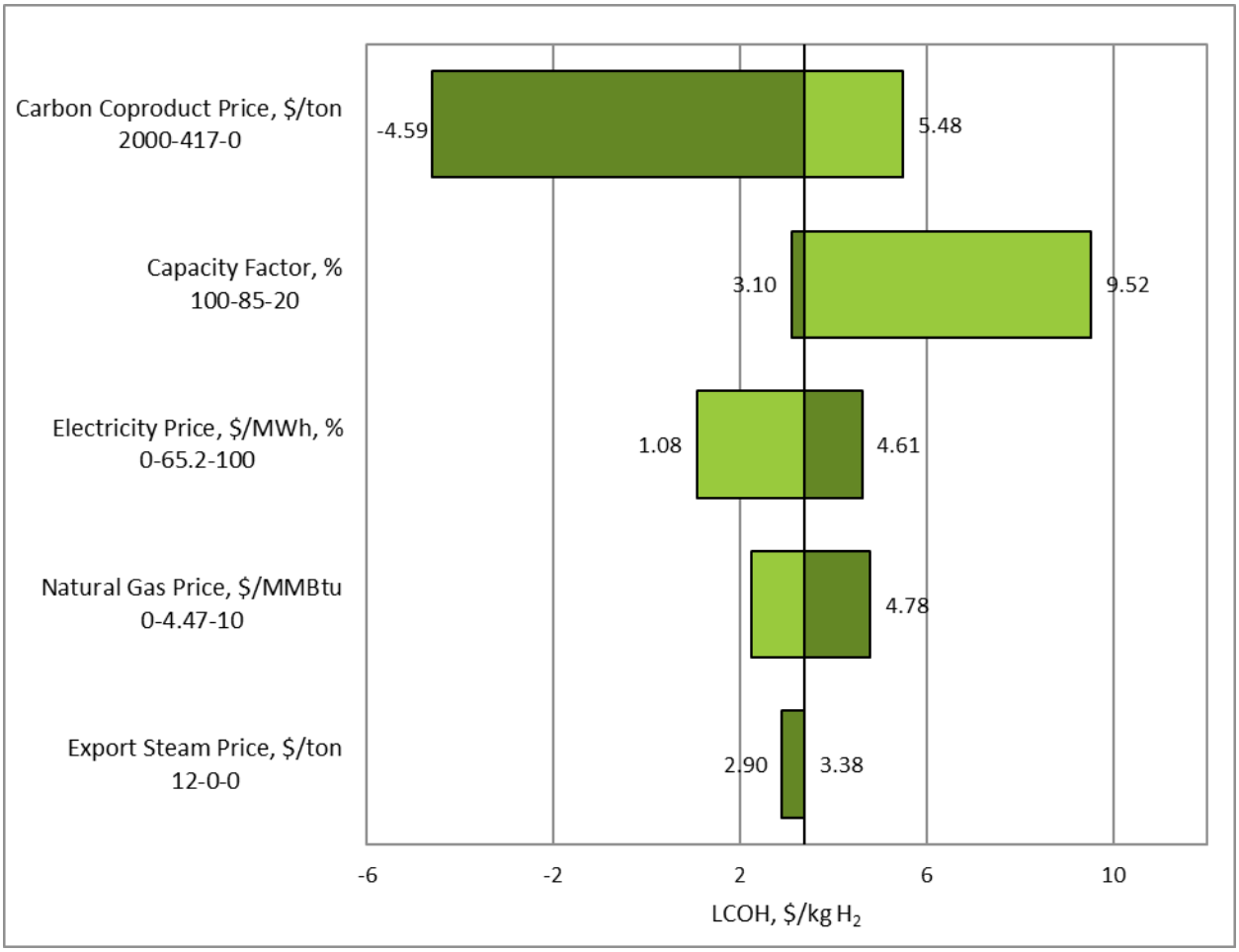


Exhibit 3-18 shows a two-parameter sensitivity analysis that adds an additional capital cost component and varies carbon coproduct price to show the effect on the LCOH. This sensitivity shows the cost tradeoff between additional capital needed to produce a higher-value carbon coproduct versus higher carbon coproduct prices. The sensitivity does not account for any impacts to the plant performance for producing a higher-value carbon coproduct. Overall, the sensitivity analysis shows that, within the shown ranges, the LCOH is more sensitive to carbon coproduct price than additional capital costs, indicating that the additional capital costs are economically advantageous. Furthermore, if additional capital costs are less than $510 MM to produce a carbon black product able to be sold at the market price of $1,870/tonne ($1,669/ton), the LCOH of the system may be less than $1/kg H_2. However, if additional capital costs are greater than $820 MM producing a higher-value carbon coproduct may not be economical since the resulting LCOH would be higher than the baseline case of $3.38/kg H_2.

Exhibit 3-18. Two-parameter sensitivity analysis varying additional capital cost and carbon coproduct price

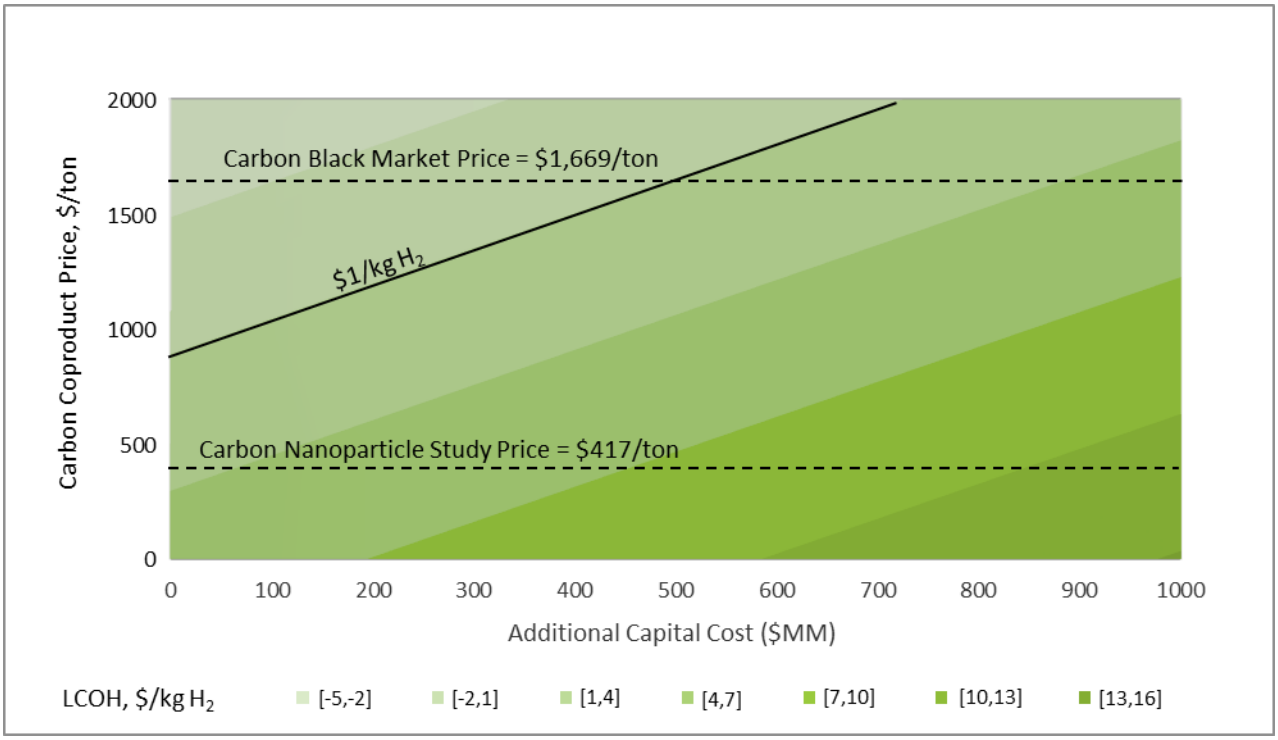


Exhibit 3-19 shows a two-parameter sensitivity analysis that varies both electricity price and CF to show the effect on the LCOH. Each area with a different shade of orange represents a range of a \$1 per kg H_2, from \$0 on the low end to \$11 on the high end. This sensitivity addresses various electricity scenarios, including the use of direct coupled variable renewable energy (VRE), which may produce low CFs. For example, in 2021, the CF of wind energy averaged 35 percent and the CF of photovoltaic solar energy averaged only 25 percent (U.S. EIA, 2022). At low CFs representing VRE and assuming an electricity price of \$0/MWh, this sensitivity shows that the LCOH may be higher, indicating that this tradeoff is not worth it from an economics perspective and brings into question operational feasibility. Another electricity scenario could include the consideration of energy storage, which may be able to maintain higher CFs while taking advantage of lower electricity prices, resulting in potential LCOH reductions of \$1/kg H_2 to \$2/kg H_2.

Exhibit 3-19. Two-parameter sensitivity analysis varying electricity price and capacity factor

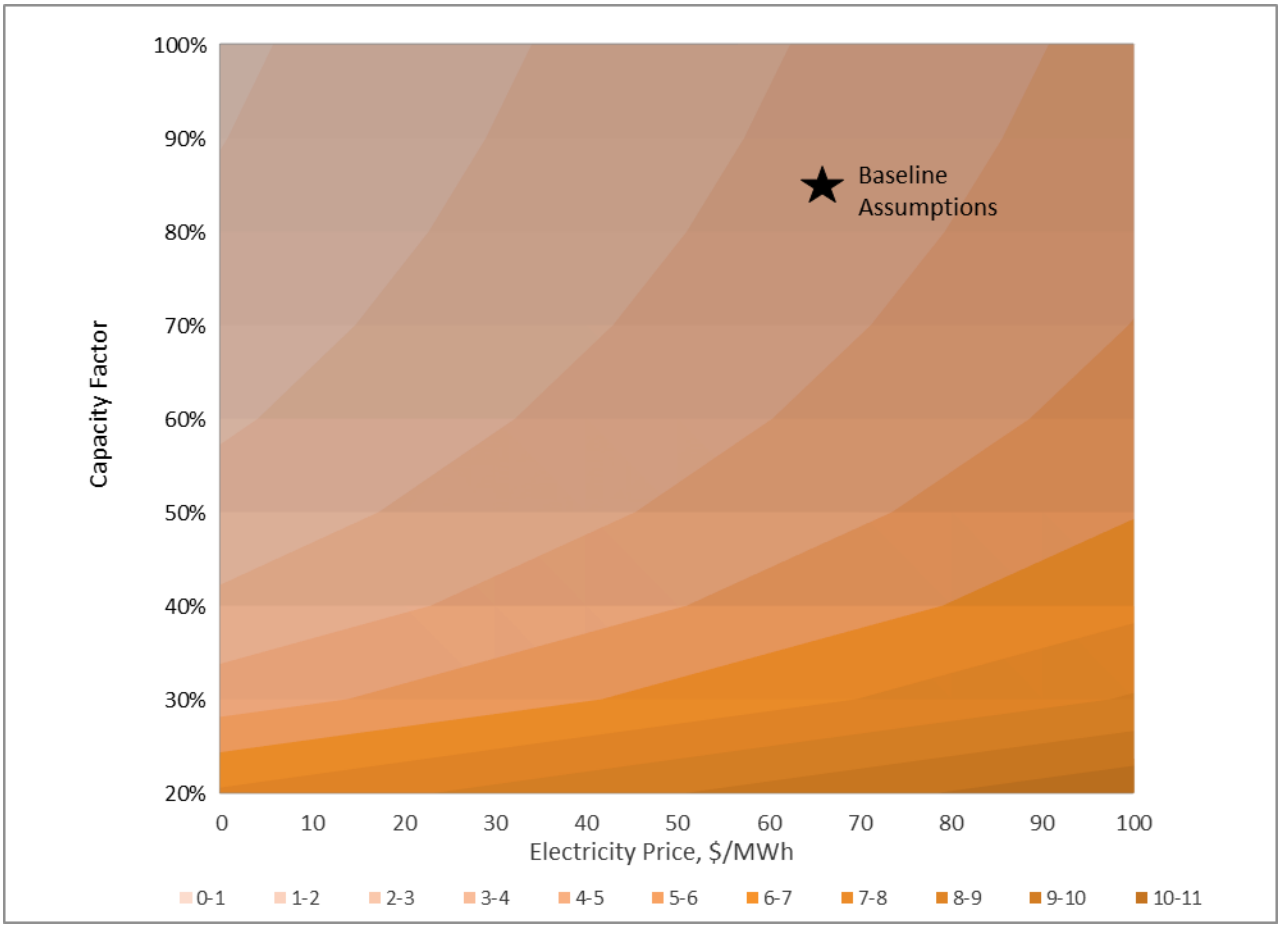
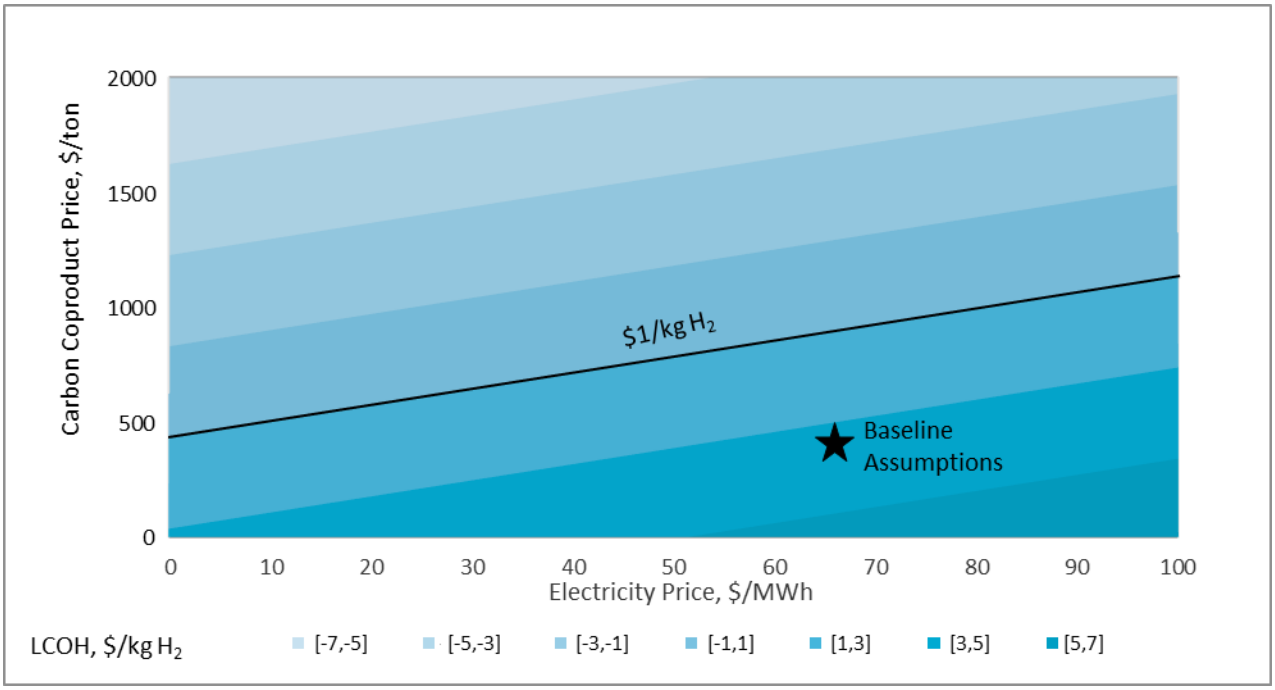


Exhibit 3-20 shows a two-parameter sensitivity analysis varying carbon coproduct price and electricity price, two major cost drivers, to determine impacts to the LCOH. The black line shows all combinations of electricity prices and carbon coproduct sales price that total an LCOH of \$1/kg H_2. At a lower bound electricity price of \$0/MWh, the carbon coproduct would need to be sold at just above \$473/tonne (\$430/ton) to offset costs and produce H_2 at \$1/kg. Conversely, if the carbon coproduct could be sold at its market price of \$1,870/tonne (\$1,669/ton), a \$1/kg goal can be achieved at electricity prices up to \$176/MWh (not shown on the graph).

Exhibit 3-20. Two-parameter sensitivity analysis varying electricity price and carbon coproduct price



4 CONCLUSION

The TEA conducted on the plasma pyrolysis process quantifies key performance and cost metrics including recovery efficiency (%), combined energy efficiency (%), and LCOH (\$/kg H_2).

The results of the TEA showed that the H_2 recovery efficiency of the plasma pyrolysis system is 83.9 percent, and the carbon recovery efficiency is 97.8 percent. The plant consumes 214 MWe of electricity. The combined energy efficiency is 62.6 percent on a HHV basis. The baseline LCOH produced from the plant is \$3.38/kg H_2. Around 46 percent of the cost is attributed to variable operating costs, primarily due to the purchase of electricity, and coproduct sales offset 38 percent of the cost.

Sensitivity analyses provide insight into the effects on the LCOH due to changes in key input variables. Parameters that influence cost the most include electricity price and carbon coproduct price. A key conclusion from the sensitivity analysis is that producing a high-value carbon product is critical for reducing the cost of H_2 produced by the plant.

The results from the study can guide RD&D to drive reductions in costs. For example, electricity consumption is a key cost driver, so emphasis should be placed on reducing electrical demand

of the plasma torch or sourcing electricity from low-cost energy sources. Furthermore, optimizing the carbon product quality and value is important to take advantage of sales revenue.

4.1 FUTURE WORK

Based on the results, further study is recommended to inform the following topics:

- Extending the TEA boundary to include various carbon products. This would be helpful since carbon coproduct sales are a key cost driver and carbon product quality is difficult to decouple from the reactor system.
- Evaluating the effect of the natural gas source, composition, and price or considering synthetic or renewable natural gas as a feedstock. The sulfur content will be an important factor given the specifications for certain carbon coproducts.
- Evaluating options for reliable, continuous, low-cost electricity.
- Understanding grid infrastructure upgrades needed to support a large-scale plasma pyrolysis plant.

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