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Technical Economic Assessment of LWR-Supported Hydrogen Markets in Gulf Coast Regions

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EXECUTIVE SUMMARY

The United States (U.S.) nuclear generation fleet is an existing key national strategic asset in meeting climate goals. Nuclear baseload power provides the largest percentage of U.S. carbon-free electrical generation and brings 24/7 clean energy stability to the grid. The existing nuclear fleet is based on light-water reactor (LWR) technologies and is reliable with a long established and proven safe operating experience and operates at high-capacity factors—typically above 90%.

The Department of Energy's (DOE) Light-Water Reactor Sustainability (LWRS) Flexible Plant Operations and Generation (FPOG) pathway is exploring research-based solutions to U.S. nuclear power plant (NPP) grid integration challenges, including those emerging from the growth of intermittent clean energy and low-cost natural gas generation to improve nuclear plant flexibility through alternate electric and heat-based revenue streams. Alternate nuclear revenue stream research at Idaho National Laboratory (INL) has identified a compelling technical and economic nexus between maturing high-temperature electrolysis technology (HTE) and excess nuclear clean steam and electricity that exists during periods of high renewables grid penetration. Nuclear-integrated hydrogen is a key aspirational element of the DOE Hydrogen Energy Earthshot initiative. The mission of the Earthshot initiative is to enable low-cost, clean hydrogen at scale, including accelerating the production, storage, delivery, and end use of clean, affordable hydrogen in the United States.

Large-scale nuclear-integrated hydrogen via HTE has broad potential as a strategic clean energy carrier in decarbonizing common energy intensive sectors, including industrial, agricultural, and transportation. Nuclear has the unparalleled potential to deliver clean electrical and/or high-temperature steam output in the form of clean electricity and/or alternate heat-based product streams during periods of low demand (i.e., during peak intermittent excess renewables). Notably, nuclear-produced hydrogen represents a breakthrough methodology with the inherent capability to provide high-purity clean H_2 well below the national standard of 2 kg of CO_2 per kg of H_2. An all-of-the-above approach based on high-capacity 24/7 technologies, including nuclear and steam methane reforming (with carbon capture sequestrations), will be necessary to support the ultimate demands of the emerging clean hydrogen economy. Practical developing and demonstrating nuclear hydrogen is also key to advancing down-stream technologies in support of decarbonized energy sectors, such as transportation, metals refining, ammonia, chemicals, and other industries.

This report is a preliminary progress report which specifically addresses hydrogen generation opportunities from NPPs in the U.S. Gulf Coast Region including Texas, Louisiana, Mississippi, Alabama, and Florida, beginning with Entergy operated NPPs. Entergy is an operator of various NPPs in this region. Future work will include the potential opportunities for direct coupling of nuclear heat with industry in the same region. This study will include both NPP capabilities to generate hydrogen as well as identification of practical nearby industrial and pipeline operator off-takers for nuclear heat and integrated hydrogen generation by HTE.

An examination has begun the market for potential hydrogen demand from the Waterford 3 Nuclear Generating Station, Riverbend Station, and Grand Gulf Nuclear Station and has yielded valuable insights into diverse demand centers within their respective regions. The exploration of demand centers for direct-reduced iron (DRI), natural gas (NG) electricity generators, refineries, ammonia, and synthetic fuels, considering distances of 50 to 100 miles, has uncovered some high-level conclusions for each NPP. Ammonia emerges as the predominant consumer of hydrogen, particularly for Grand Gulf Nuclear Station and Riverbend Station, while DRI displays the least demand. Notably, the distribution of future potential hydrogen demand centers for Grand Gulf Nuclear Station and Riverbend Station is primarily concentrated within the 50 to 100-mile range, whereas for Waterford 3 Nuclear Generating Station, demand centers are clustered within a 50-mile radius. Ammonia production is the largest consumer of hydrogen near Waterford, followed by refineries.

A technoeconomic assessment (TEA) has begun for the Waterford 3 Nuclear Generating Station, utilizing the Nuclear-Integrated Hydrogen Production Analysis (NIHPA) tool and has generated crucial financial performance metrics. These metrics encompass pre-tax levelized cost of hydrogen (LCOH), internal rate of return (IRR), Net Present Value (NPV) for hydrogen production, Net Present Value for business as usual, and ΔNPV. The sensitivity analysis, focused on LCOH and NPV, underscores the significance of hydrogen market price and production tax credit (PTC) as the most influential parameters affecting NPV. The profitability analysis indicates that a minimum selling price of $3 per kilogram of hydrogen would be required to ensure market competitiveness, particularly in scenarios where only a partial tax credit is obtained. Preference analysis reveals a favoring of nuclear-integrated hydrogen production over selling electricity to the grid when electricity prices range from $10 to $60 per MWh. In the realm of competitive analysis, it has been determined that nuclear-integrated hydrogen production with a full PTC should be competitive with hydrogen production from Steam Methane Reforming (SMR) with Carbon Capture Sequestration (CCS) under specific conditions. This includes an NG price above $4 per MMBtu or electricity prices below $65.45 per MWh.

In essence, the findings from this comprehensive analysis lay a robust foundation for future work in developing the strategic decision-making data regarding hydrogen production at the Waterford 3 NPP, providing insights into the economic viability and competitiveness of nuclear-integrated hydrogen production in the evolving energy landscape, and expanding these analyses to all U.S. gulf coast NPPs.

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ACRONYMS

A&M	Agricultural and Mechanical
ASU	Air separation unit
BASF	Baden Aniline and Soda Factory
BAU	Business-as-usual
BOP	Balance-of-plant
BWR	Boiling Water Reactor
CAPEX	Capital Expenditure
CCS	Carbon Capture Sequestration
CF	Central Farmers
CT	Combustion turbines
DCC	Direct capital cost
DOE	Department of Energy
DRI	Direct Reduced Iron
EAF	Electric arc furnace
EIA	Energy information administration
FPOG	Flexible Plant Operations and Generation
FT	Fischer-Tropsch
GHG	Greenhouse Gas
HTE	High-temperature electrolysis
HTSE	High-temperature steam electrolysis
HYSYS	CHECK TEXT / EXISTING GLOSSARY FOR DEFINITION
IAEA	International Atomic Energy Agency
INL	Idaho National Laboratory
IRA	Inflation Reduction Act
IRR	Internal rate of return
LCOH	Levelized cost of hydrogen
LSU	Louisiana State University
LTE	Low-temperature electrolysis
LWR	Light-Water Reactor
LWRS	Light-Water Reactor Sustainability
MT	Metric Ton
NG	Natural Gas
NIHPA	Nuclear-integrated hydrogen production analysis

NPP	Nuclear Power Plant
NPV	Net Present Value
NPVBAU	Net Present Value of Business-As-Usual
PI	Prairie Island
PTC	Production tax credit
PWR	Pressurized Water Reactor
SMR	Steam Methane Reforming
TEA	Techno-Economic Assessment
US	United States
WACC	Weighted averaged of capital

1. INTRODUCTION

The U.S. Gulf Coast region, recognized for its pivotal role in the global energy landscape, has witnessed a surge in interest surrounding the integration of light-water reactors (LWRs) to support clean electricity, heat, and hydrogen markets for energy and industry with the goal of staged decarbonization. Recognized for its dominance in oil and gas and chemicals production, the region is prime for the exploration of integrating nuclear energy streams of heat, power, and hydrogen with existing industry.

Light-water reactors (LWRs), a cornerstone of nuclear power generation, have a history of providing reliable electricity. The feasibility of leveraging these reactors to provide direct heat, electricity and to produce hydrogen for existing industry marks a paradigm shift, offering a unique opportunity. Against this backdrop, this preliminary report of the progress of the technoeconomic assessment (TEA) of LWR-supported heat, power, and hydrogen supply to existing industry in the Gulf Coast region emerges as a critical investigation, poised to unravel the intricate dynamics of nuclear energy and its role in industrial decarbonization.

The Gulf Coast region, known for its industrial prowess and strategic importance in the energy sector, serves as an ideal case study for this assessment. With a rich history in petrochemical production, the region is poised for a transition toward a more sustainable and diversified energy portfolio. Examining the potential synergies between LWRs and industrial demands for clean heat, power, and hydrogen markets in the Gulf Coast offers insights not only into economic considerations but also into the broader implications for regional energy security and environmental sustainability. This preliminary progress report begins the thorough TEA to scrutinize the feasibility and economic viability of utilizing LWRs to support hydrogen production and direct heat use for industries in the Gulf Coast region. It seeks to identify opportunities for NPP heat, power, and hydrogen with existing industries and detail the integration of these energy streams with industry. Through a nuanced examination of technological, economic, and regional factors, this assessment aims to illuminate the path toward a sustainable, low-carbon energy future for the Gulf Coast and potentially serve as a model for similar transitions globally.

A comprehensive economic analysis will shed light on the cost-effectiveness and potential challenges associated with this innovative approach. This report aims to provide stakeholders, policymakers, and industry leaders with a nuanced understanding of the technoeconomic landscape, empowering them to make informed decisions that contribute to the sustainable energy future of the Gulf Coast region and beyond.

The market analysis begins with an in-depth examination of the current state of hydrogen demand in the Gulf Coast region, specifically for Waterford 3 Nuclear Generating Station, Riverbend Nuclear Station, and Grand Gulf Nuclear Station. Understanding the specific needs, demands, and preferences of industries, including petrochemicals, transportation, and power generation, provides a foundation for forecasting future demand trends. Market dynamics such as pricing, supply chains, and regulatory frameworks will be examined to identify key drivers and potential obstacles. By considering both domestic and international market forces, the analysis aims to paint a comprehensive picture of the Gulf Coast's position in the global hydrogen landscape. This TEA will also delve into economic factors, assessing capital and operational costs, projected returns on investment, and the competitiveness of LWR-supported heat and hydrogen production for industry. This multifaceted evaluation ensures a thorough understanding of the technical and financial dimensions, allowing stakeholders to gauge the feasibility and sustainability of such an innovative energy paradigm.

2. HYDROGEN MARKET ANALYSIS

This section first discusses the U.S. national market potential, size, and location for hydrogen, which could be produced in an integrated facility with NPPs. Then life-cycle CO_2 emissions reduction associated with nuclear-produced H_2 for these markets are reported. Next, the potential hydrogen demand around selected NPPs on the Gulf Coast are categorized and discussed.

2.1 Methodology

2.1.1 National Potential Hydrogen Demand

The national potential hydrogen demand is estimated from data from multiple sectors such as transportation, manufacturing, and power generation. Specific applications include fuel cell electric vehicles, co-firing hydrogen with natural gas (NG) in combustion turbines, petroleum refineries, direct-reduced iron for metals, ammonia and fertilizers production, and synthetic fuels production. We summarize how the hydrogen demand for these applications is estimated in Table 1. Readers may refer to the detailed account of these computations in the 2021 report[#].

Table 1. Summary of assumptions and data sources for computation of future potential hydrogen demand in the U.S.[#]

End Use	Main Assumptions & Data Sources	Background Information, If Any	Off-set in CO_2 Emissions
Hydrogen Blending with Natural Gas in Combustion Turbines	Potential demand is estimated for hydrogen by assuming it can be used by NG CTs with a volume ratio of 30% hydrogen blended with 70% NG. Electricity generators were identified using the data sets from the EIA-860 and EIA-923 forms describing electricity generator facility locations and fuel use.	The clean hydrogen produced from the nuclear energy can be injected into NG pipelines for use as a low-carbon green component of a natural gas/hydrogen fuel mix for general heating or for exclusive use in combustion turbines (CTs) for power generation.	The life cycle GHG emissions are estimated at 493 g CO_2e/kWh when using only NG as the feed, and 442 g CO_2e/kWh for the mixture of 30% hydrogen and 70% NG by volume for different NG turbines technology shares.
Petroleum Refineries	The crude inputs are estimated to increase from 16 to 18 Mbbl/d (with a steeper increase of 9% from 2015 to 2021 and then a more gradual increase to 2050), gasoline output decreases from 8 to 6 Mbbl/d, diesel output increases slightly, and average jet-fuel output increases roughly 0.5 Mbbl/d from about 1.7 to 2.2 Mbbl/d. Based on these assumptions, in addition to	Hydrocracking is used to produce diesel from heavy crude, and hydrotreating is used to remove sulfur from feed, intermediate, and product streams. Hydrogen is used in these two processes. This hydrogen can be produced internally in a refinery via catalytic reforming of naphtha. Hydrogen produced from the NPPs can be substitute/complement the internally produced hydrogen.	The well-to-gate CO_2e p emissions for H_2 produced from NG SMR and high-temperature electrolysis (HTE) (nuclear) are estimated to be 9.28 kg CO_2e / kg H_2 and 0.15 kg CO_2e/kg H_2, respectively.

End Use	Main Assumptions & Data Sources	Background Information, If Any	Off-set in CO_2 Emissions
	the internal hydrogen production via catalytic reforming of naphtha, the total U.S. hydrogen demand for petroleum refining is estimated as 5.9 MMT/year in 2017 and 7.5 MMT/year in 2050.		
Direct Reduced Iron (DRI) for Metals Refining and Steel Production	DRI process, using 100% hydrogen as the reducing agent, requires up to 100 kg hydrogen per MT of steel—i.e., a mass ratio of approximately 10%. However, using hydrogen in a blend with NG up to 30/70 ratio by energy to produce DRI would not require modifications to the original technology which was developed to work solely with NG. We estimate the potential hydrogen demand for DRI was based on using 30% hydrogen and 70% NG on an energy basis.	The DRI is a process developed by Midrex Technologies, Inc., for producing high-purity iron from ore at temperatures below the melting point of iron by reducing the iron oxide ore and driving off oxygen in a reactor using a reducing agent. The reducing agent can be carbon coke, hydrogen, or syngas. DRI is converted to steel in an electric arc furnace (EAF).	The GHG emissions from each respectively is: 1.97-MT eq.CO_2 /MT steel from a blast furnace (BF), 1.47-ton eq.CO_2 /MT steel from an EAF using 100% NG, 1.28-MT eq.CO_2 /MT steel from EAF using 70% NG and 30% Nuclear H_2, and 0.99-MT eq.CO_2 /MT steel from EAF using only nuclear-H_2.
Ammonia and Fertilizers	25% increase in hydrogen demand for NH_3 production between 2017 and 2024 is estimated. We assume that domestic hydrogen demand for NH_3 production beyond 2024 would grow by another 15% by 2050.	Ammonia is produced by the Haber-Bosch process, in which hydrogen and nitrogen separated from the air react. The hydrogen is usually produced from NG react via the steam methane reforming (SMR) process. This hydrogen can be substituted using clean hydrogen produced via nuclear energy.	The conventional pathway produces about 2.55 MT CO_2/MT NH_3 while the nuclear for both H_2 and air separation unit (ASU) produce 0.06 MT CO_2/MT NH_3, respectively, on a life-cycle basis.

End Use	Main Assumptions & Data Sources	Background Information, If Any	Off-set in CO_2 Emissions
Synthetic Fuels	Syn fuels can be used for carbon intensive energy sector end uses like transportation. Hence, the production and use of syn fuels can significantly support the efforts toward decarbonization. The hydrogen demand for synfuel production can be estimated based on the stoichiometric 1:3 mole ratio of CO_2 to H_2 that is required for the synthesis of Fischer-Tropsch diesel or dimethyl ether.	Synthesis gas (syngas) is a mixture of carbon monoxide and hydrogen. It is called syngas because these two molecules can be used to synthesize synthetic fuels (synfuels) and chemicals (synchemicals). Significant quantities of high-purity CO_2 are generated in industry processes such as ethanol production, SMR used for hydrogen production from NG for refining, and ammonia production. These high-concentration CO_2 sources present opportunities to produce synfuels and synchemicals using a wide variety of pathways while minimizing the cost and energy penalty to capture CO_2 relative to other dilute CO_2 sources (e.g., from flue gases of coal and NG power plants).	The GHG emissions per megajoule for various fuels like gasoline, jet fuel, diesel fuel, and FT fuel (using nuclear H_2) are 93, 86, 91 and 9 g CO_2 eq./MJ, respectively.

2.2 Results and Analysis

2.2.1 Future Potential Hydrogen Demand for Specific NPPs

In this section, we use the data produced for the national potential hydrogen demand to analyze the potential hydrogen demands for Waterford 3 Nuclear Generating Station, Riverbend Station, and Grand Gulf Nuclear Station. Detailed tables of various facilities within 100 miles of each of these NPPs that may demand hydrogen in future are provided in Appendix 1. Since a 500-MW plant could produce about 300 MT/day of hydrogen, the potential for each of the following NPPs can be examined through this lens. Another key assumption is that for the maps we have plotted the NG pipelines. This is because at present we do not have clear information on hydrogen pipelines.

2.2.1.1 Waterford Nuclear Generating Station

The Waterford Steam Electric Station (shown in Figure 2) is a NPP with a rated capacity 1152 MWe (potential of producing more than 600 MT/day) located in Louisiana. It is a pressurized water reactor with a thermal capacity of 3716 MW. It generates about 7–10 TWh per year.

The future potential demand for hydrogen from this plant from facilities in 100 miles is 6498 MT per day. More detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 3 and Figure 4. Ammonia production is the largest consumer of hydrogen, followed by refineries.

It may be noted that for this NPP, more than half of the total hydrogen demand centers are located within 50 miles.

The largest hydrogen demand centers in the 100 miles of Waterford NPP for ammonia production are CF Industries in Donaldsonville and Eurochem in Edgard with 1868 and 430 MT/day, respectively. Refineries such as Exxon Mobil Corp in Baton Rouge and Marathon Petroleum Corp in Garyville with 535 and 578 MT/day, respectively can also contribute to the hydrogen demand. The potential demand for industrial heat from a nearby Dow chemical plant will be estimated and reported in future work. These demands contribute to more than half of the total demand potential demand for hydrogen.

Figure 2. Waterford Steam Electric Station, Unit 3.

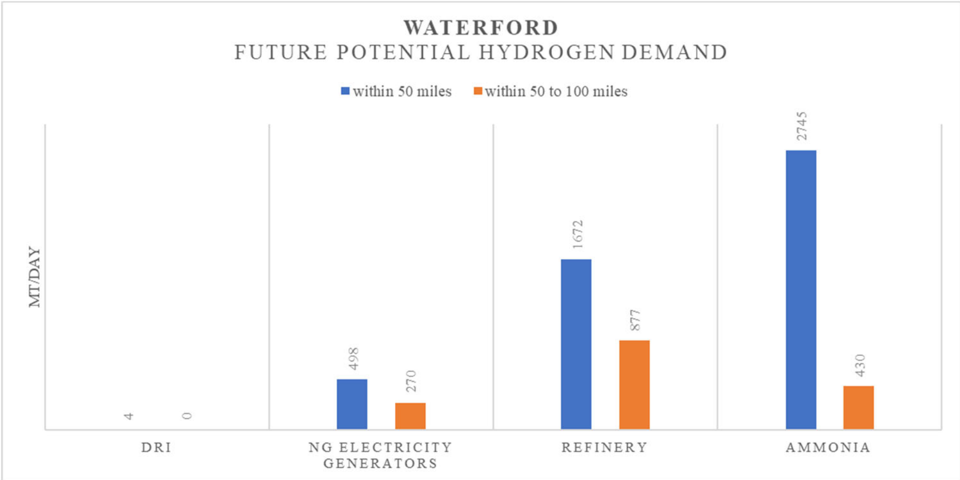
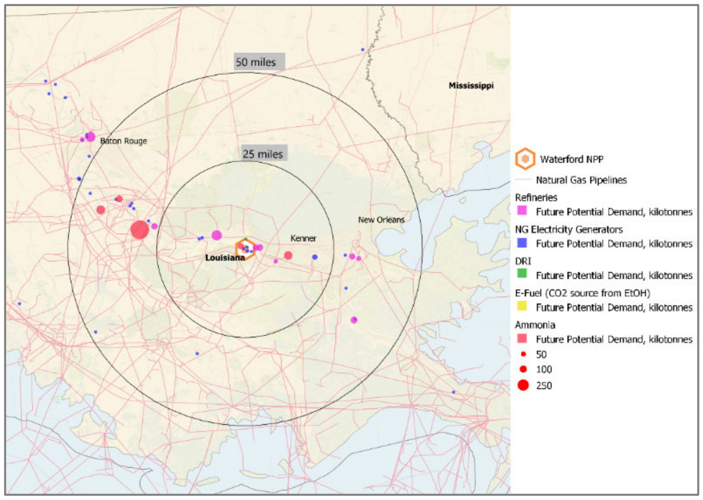
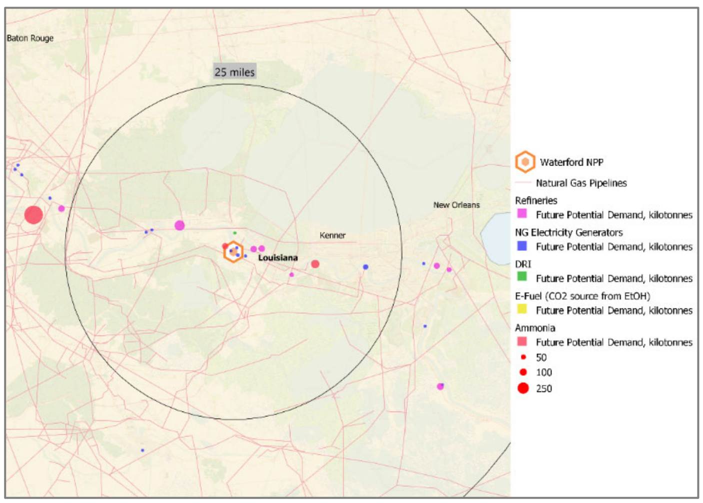


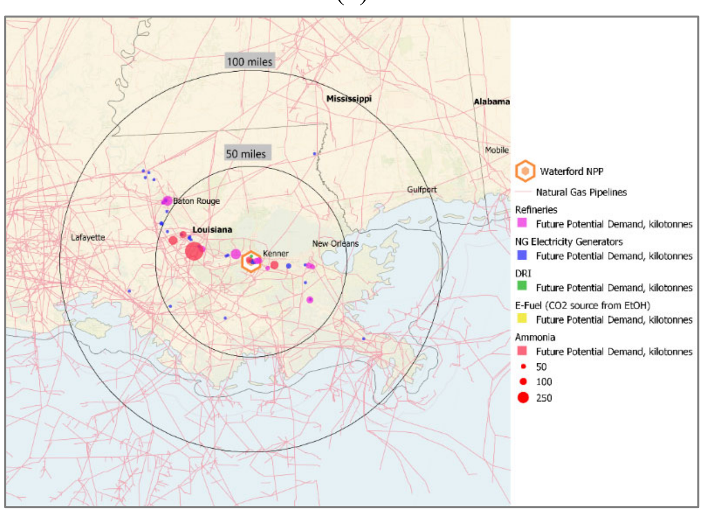
Figure 3. Distribution of future potential demand for hydrogen in the neighborhood of Waterford NPP.



(a)



(b)



(c)

Figure 4. Centers for hydrogen demand for Waterford NPP (a) in 50 and 25 miles (b) 25 miles (c) 50 and 100 miles.

2.2.1.2 Riverbend Station

The Riverbend Station (shown in Figure 5) is a NPP with a rated capacity 974 MWe (potential of producing close to 600 MT/day) located in Louisiana. It is a sixth-generation General Electric boiling water reactor with a thermal capacity of 3091 MW. It generates about 7–9 TWh per year.

Total future potential demand of hydrogen from facilities in 100 miles of Riverbend NPP is 5511 MT/day. More detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 6 and Figure 7. Ammonia production is the largest consumer of hydrogen, followed by refineries. It may be noted that for this NPP, more than half of the total hydrogen demand centers are located beyond 50 miles.

This plant is located close to the Waterford 3 Nuclear Generating Station. Hence, the demand centers for the future potential demand for hydrogen from this plant are common. The largest hydrogen demand centers in the 100 miles of Riverbend Station for ammonia production are CF Industries in Donaldsonville and Eurochem in Edgard with 1868 and 430 MT/day respectively. Refineries such as Exxon Mobil Corp in Baton Rouge and Marathon Petroleum Corp in Garyville with 535 and 578 MT/day, respectively can also contribute to the hydrogen demand. These demands contribute to more than half of the total demand potential demand for hydrogen.

Figure 5. River Bend Station, Unit 1.

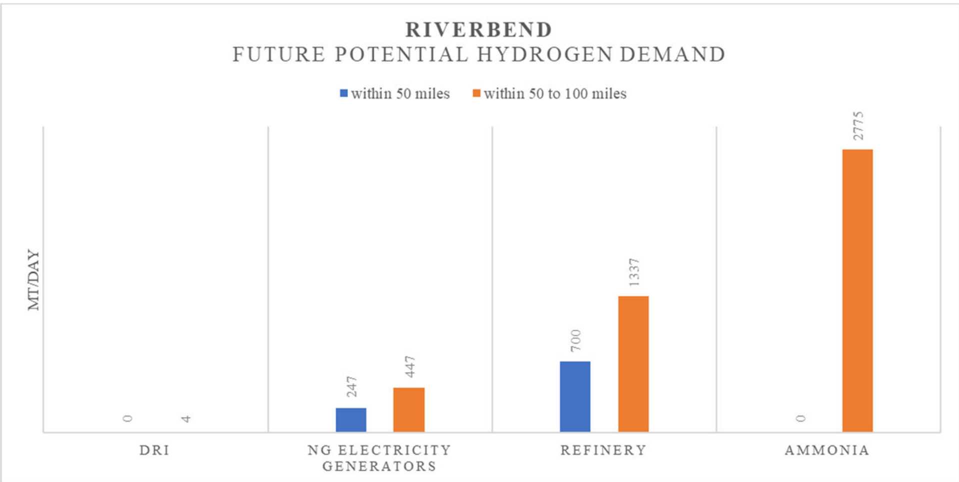
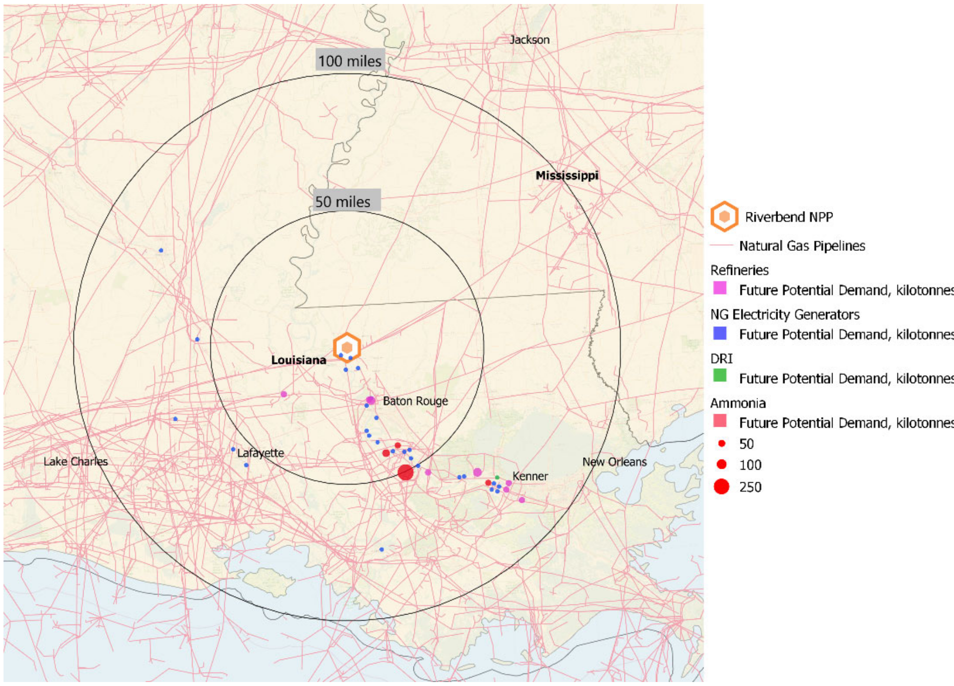
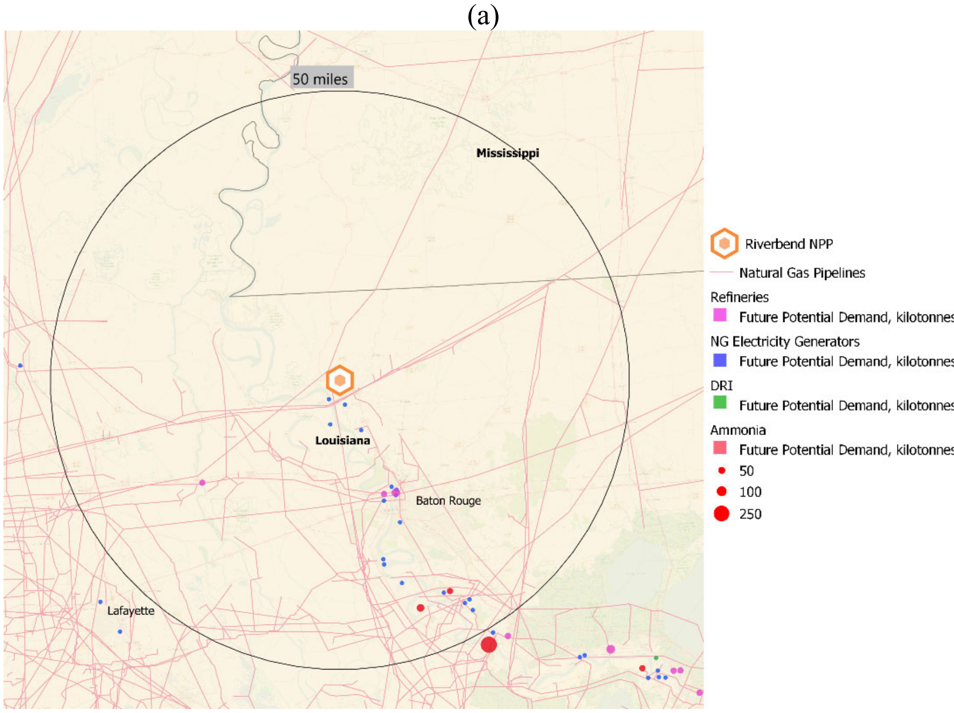


Figure 6. Distribution of future potential demand for hydrogen in the neighborhood of Riverbend Station.



(a)



(b)

Figure 7: Centers for hydrogen demand for Riverbend Station (a) in 100 and 50 miles (b) 50 miles.

2.2.1.3 Grand Gulf Nuclear Station

The Grand Gulf Nuclear Station (shown in Figure 8) is an NPP with a rated capacity of 1443 MWe (potential of producing close to 900 MT/day) located in Mississippi. It is a boiling water reactor with a thermal capacity of 4408 MW. It generates about 7–12 TWh per year.

The future potential demand for hydrogen from this plant from facilities in 100 miles is 412 MT per day. More detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure

9 and Figure 10. Ammonia production is the largest consumer of hydrogen, followed by refineries. It may be noted that for this NPP, more than 50% of the total hydrogen demand centers are located beyond 50 miles.

The largest hydrogen demand centers in the 100 miles of Grand Gulf Nuclear Station are most diverse. For ammonia production Cf Industries in Yazoo City may demand 249 MT/day where as Ergon Biofuels LLC in Vicksburg may have a potential demand of 55 MT/day for Syngas: Ethanol production. Hinds Energy Facility: Entergy Mississippi Inc and Ergon Inc, Vicksburg may need 45 and 28 MT/day of hydrogen for NG Electricity Generators and Refinery usage. These demands contribute to more than 90% of the total demand potential demand for hydrogen from this NPP.

Figure 8. Grand Gulf Nuclear Station, Unit 1.

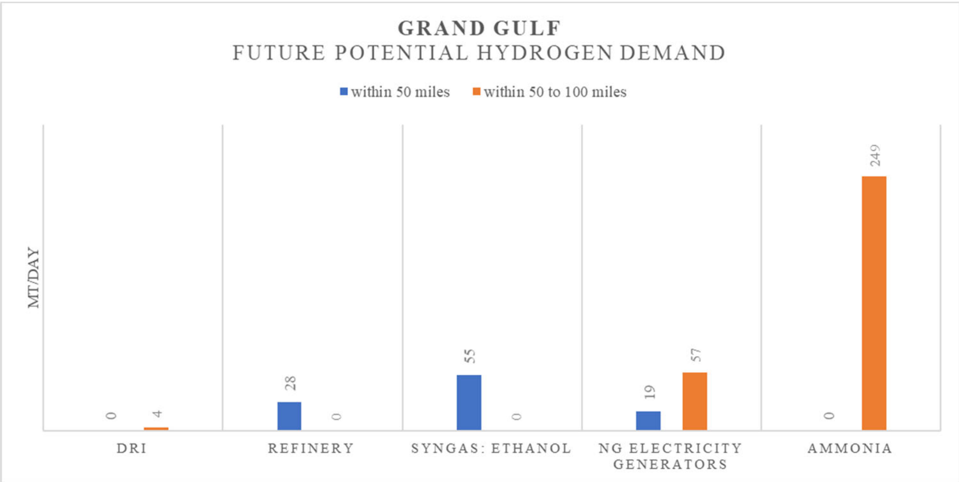
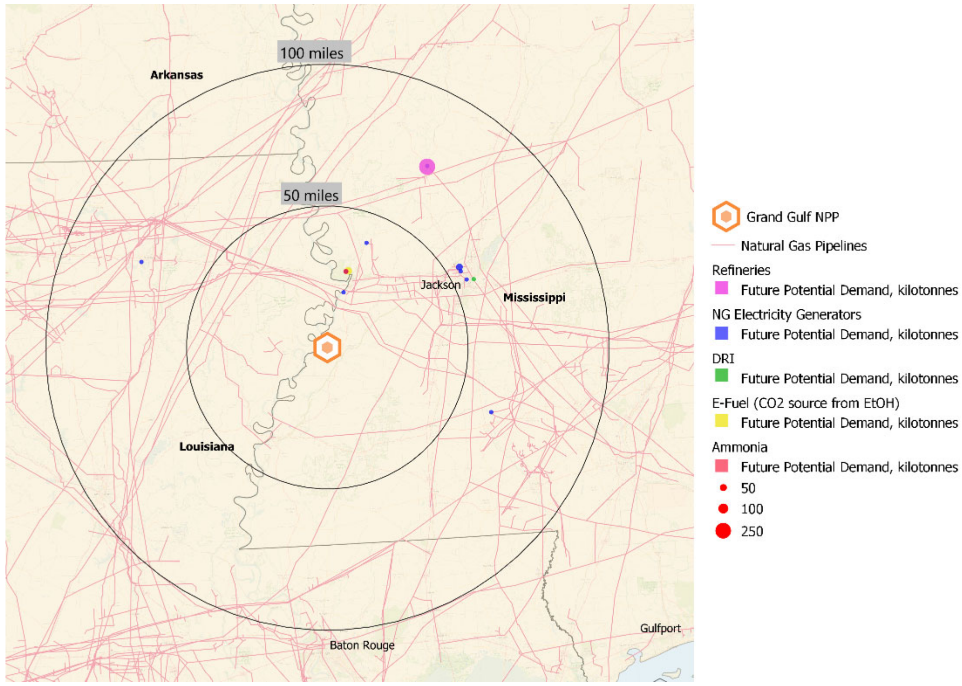
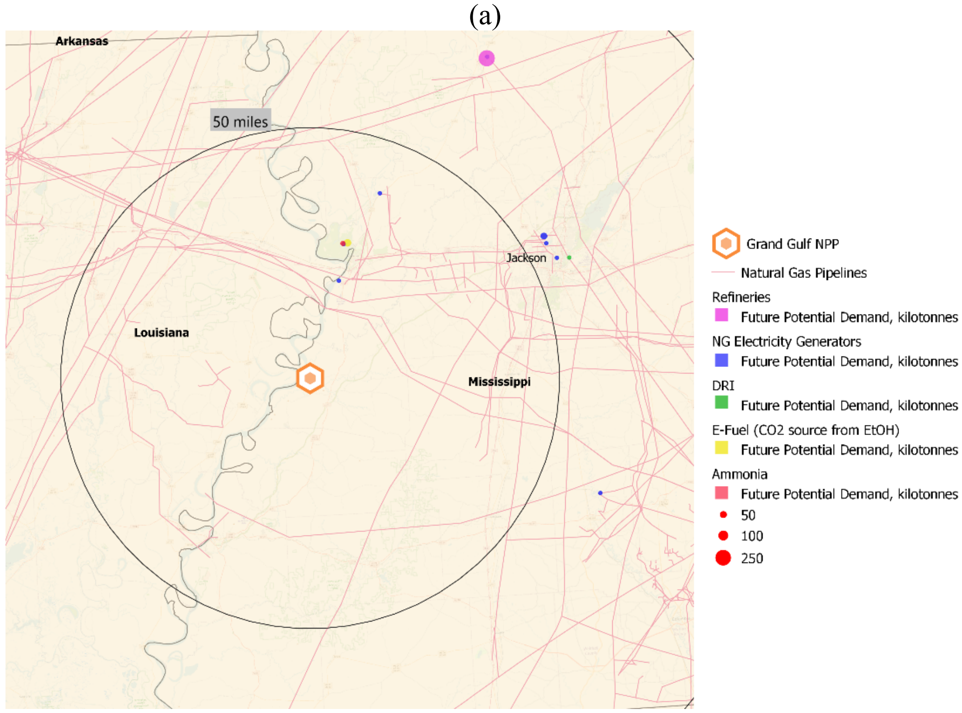


Figure 9. Distribution of future potential demand for hydrogen in the neighborhood of Grand Gulf Nuclear Station.



(a)



(b)

Figure 10: Centers for hydrogen demand for Grand Gulf Nuclear Station (a) in 100 and 50 miles (b) 50 miles

3. TECHNICAL ECONOMIC ASSESSMENT OF LWR INTEGRATED HYDROGEN PRODUCTION

Previous TEA have been performed showing the potential for nuclear-integrated hydrogen production including 1) Xcel Energy's Prairie Island (PI) and Monticello nuclear generating stations and [1] 2) a generalized gigawatt-hour high-temperature steam electrolysis (HTSE) plant integrated with a hypothetical PWR [2]. 3) specification of reversible solid oxide system in which the LCOH was estimated by adopting the cash flow analysis from NREL H2A model [3] with updated direct capital costs estimation by adding component specific cost for each HTSE plant [4]. Recently a calculation tool has been developed using all of these TEAs as a baseline for the calculations and is called the [5] Nuclear-Integrated Hydrogen Production Analysis (NIHPA) tool and it is used for the calculations in this report.

3.1 Methodology

The TEA in this report is performed based on the NIHPA tool [5] developed at Idaho National Laboratory (INL). The NIHPA tool was verified against NREL H2A model [3] and the default values were adopted from the 2023 hydrogen market report [4]. The NIHPA tool was developed for a pressurized water reactor, where portions of the heat and electricity were used to power the electrolysis for hydrogen production. The original version of NIHPA tool focused on HTSE with the specific operating conditions shown in Table 1; however, the developers are working on extending the features of the NIHPA tool to (1) perform TEA for low-temperature electrolysis (LTE), and (2) perform adapt the tool for boiling water reactor (BWR) integrated high-temperature hydrogen production. Table 2 below shows the assumptions used in this analysis.

Table 1. HTSE and related subsystem process operating condition specifications (INL/RPT-22-66117) [2].

Parameter	Value	Reference or Note
Stack operating temperature	800°C	O'Brien et al. 2020 [6]
Stack operating pressure	5 bar	See INL/RPT-22-66117 Section 2.2.1 [2]
Operating mode	Constant V	
Cell voltage	1.29 V/cell	Thermoneutral stack operating point
Current density	1.5 A/cm²	James and Murphy 2021 [7]
Stack inlet H_2O composition	90 mol%	O'Brien et al. 2020 [6]
Steam utilization	80%	See INL/RPT-22-66117 Section 2.2.1 [2]
HTSE modular block capacity	25 MW-dc	Estimates presented in this document require consideration of fractional modules (i.e., system capacities evaluated are < 25 MW-dc)
Sweep gas	Air	O'Brien et al. 2020 [6]
Sweep gas inlet flow rate	Flow set to achieve 40 mol% O_2 in anode outlet stream	
Stack service life	4 years	HFTO Hydrogen Production Record 20006 [8]

Parameter	Value	Reference or Note
Stack degradation rate	0.856%/1000 hr	HFTO Hydrogen Production Record 20006 [8]
Stack replacement schedule	Annual stack replacements completed to restore design production capacity	Based on NREL H2A model stack replacement cost calculations [3]
H_2 Product Pressure	20 bar	
H_2 Product Purity	99.9 mol% H_2	Water condensation from cooling and compression only; no PSA / TSA steps included

The NIHPA tool utilizes the cashflow analysis to calculate levelized cost of hydrogen (LCOH), IRR, net present value (NPV), and ΔNPV defined as the difference between NPV of hydrogen production and NPV of business-as-usual (BAU) cases. The BAU Case is where the electricity that would be used to produce hydrogen is sold to the grid.

As shown in (1), the LCOH is estimated based on the summation of seven cost contributors, including electricity (C_{ele}), thermal energy (C_{th}), stack (C_{stack}), balance-of-plant [BOP] (C_{BOP}), fixed operation and maintenance (C_{fixed_OM}), variable operation and maintenance (C_{var_OM}), and stack replacement cost (C_{stack_rep}) with respect to the hydrogen production (S_{H2}) in the unit of kilograms.

$$LCOH = \frac{(C_{ele} + C_{th} + C_{stack} + C_{BOP} + C_{fixed\_OM} + C_{var\_OM} + C_{stack\_rep})}{S_{H2}}, \tag{1}$$

The sum of stack and BOP costs is equivalent to capital expenditure (CAPEX), which is calculated by adding both depreciable and non-depreciable CAPEX together. The depreciable CAPEX includes the direct and indirect capital costs, where the direct capital cost (DCC) is calculated using (2), where PC_{HTSE} represents the HTSE plant capacity in MW-dc. The coefficients in (2) are obtained by fitting the DCC data from the INL NPP-HTSE studies [9] with HTSE plant capacity varied from 10-1000 MW-dc.

$$DCC = 10^{3.1065} * (PC_{HTSE})^{-0.1256} * 1000 * PC_{HTSE}, \tag{2}$$

Note that (2) is applicable for HTSE plant operating based on the conditions from Table 1, the DCC may vary from changing different design when integrating HTSE with other type of reactors (e.g., BWR, other advanced water reactor). Three sources of revenue were analyzed, revenue from selling the hydrogen, from selling the electricity, and from the production tax credits. The revenue of the hydrogen production is obtained by selling the hydrogen based on the hydrogen market price. The revenue from electricity sales is obtained from selling the remaining electricity produced with respect to the NPP design power capacity to the grid. The NPV and IRR are calculated based on cash flow analysis for the entire HTSE plant life, as shown in (3).

$$NPV = \sum_{i=1}^{n} \frac{CF_i}{(1 + WACC)^i}, \tag{3}$$

where CF_i represents the cash flow in the i^{th} year from the present year. n is the total plant lifetime for discounted cash flow analysis, which is assumed to be equivalent to the HTSE plant life. The examples of weighted averaged of capital (WACC), n, and PTC are showed in Table 2. To estimate CF_i, the hydrogen market price is required, and two different modes are available: (1) "Breakeven Case" to assume that hydrogen market price is the same as LCOH, and (2) "Market-defined Case" to assign a user-defined hydrogen market price. The positive NPV indicates that the present value of the investment generates a profit. In HTSE H_2 profitability tool, there are two different calculations of NPV: (1) NPV_{H2} and (2) NPV_{BAU}. NPV_{H2} represents the NPV of the hydrogen production based on NPP-HTSE, whereas NPV_{BAU} represents the NPV of the BAU Case, where the electricity required to power HTSE is sold to the grid instead of being used as the feedstock for hydrogen production.

The IRR is calculated using (3) by solving for WACC and setting NPV equal to zero. The case with an IRR greater than WACC indicates that the investment is profitable. The most profitable investment case is found when the NPV is positive, and IRR is greater than WACC (see Step 4 for an explanation).

ΔNPV is the difference between NPV estimated for NPP-HTSE and NPV for the BAU Case as shown in (4).

$$\Delta NPV = NPV_{H2} - NPV_{BAU}, \tag{4}$$

A positive ΔNPV indicates that producing hydrogen using NPP-HTSE is more profitable than only selling electricity to the grid. Therefore, producing hydrogen using NPP-HTSE is preferred; otherwise, selling electricity without producing hydrogen (i.e., BAU) is preferred.

3.2 Results and Analysis

3.2.1 Input Specifications

There are a total of 122 inputs in NIHPA tool [5] that are available to be changed based on users' specification. These inputs are categorized into four categories: NPP specific inputs, HTSE/LTE specific inputs, financial inputs, and cost contributors for LCOH.

To apply the NIHPA tool for the Waterford 3 Nuclear Generating Station, the following updates were made compared to the default values used in NIHPA tool [5]:

- NPP capacity factor is changed to 87.4%, which is the operation factor listed on International Atomic Energy Agency (IAEA) websites [10].
- NPP thermal efficiency is changed to 31.43% calculated based on the 3716 MW-t and 1168 MW-ac for Waterford-3 NPP.
- The default value for additional stack costs related to contingency is 10% while additional stack costs related to markup is 30%.
- The year of interest is 2022. Each of the inputs associated with the dollar values are in the year 2022.
- The debt interest rate is 7.5%, while state tax is 4.45%.

The other inputs are adopted using the default values or calculated using the default formula in NIHPA tool [5]. The critical common inputs are shown in Table 2.

Table 2. Common critical inputs for NPP-HTSE.

Parameters	Values	Notes
Plant Design Capacity	351 tonne/day H_2	Based on the hourly hydrogen production rate of 0.7312 tonne/hour from HYSYS Process model result
Plant Output	306 tonne/day H_2	Based on operating capacity factor of 87.1% (90% plant availability and 96.7% cell degradation-adjusted avg annual performance)

Parameters	Values	Notes
Power Requirement	500 MW-dc 538 MW-ac	-DC power corresponds to stack power input; -AC power corresponds to total power requirement
Thermal Requirement	94 MW-t	Heat input from NPP steam
Efficiency (HHV)	90%	Includes both thermal and electrical energy input
Electricity Required	36.8 kWh-e/kg-H_2	Process model result
Thermal Energy Required	6.4 kWh-t/kg-H_2	Process model result
Technology Horizon	First-of-a-Kind plant	Equipment cost reductions from learning effects not considered
Stack Cost ($2022)	$152.66/kW-dc (1000 MW/yr mfg)	Value reported from Design for Manufacturing and Assembly analysis of an electrode-supported cell stack with specified manufacturing rates [7]
Service Life	4 years	Assumes annual stack replacements to restore the HTSE plant design capacity rating at the start of each operating year; consistent with the Current Technology Case in [8]
Utilities Process Water Feed Rate Cooling Water Circ. Rate	 36 kg/s (577 gpm) 585 kg/s (9290 gpm)	
Direct Capital Cost ($2022)	$993/kW-dc	Includes the capital cost of the nuclear process heat delivery system; excludes costs of any required NPP modifications
Total Capital Investment ($2022)	$1417/kW-dc	Includes indirect costs (site preparation, engineering & design, contingency, land, etc.)
HTSE Plant Life	20 years	
Weighted Average Cost of Capital	12.10%	This has the same meaning as discount rate in the cash flow analysis
Production Tax Credit (PTC)	$3/kg-$H_2$	The maximum PTC offered based on IRA for 10 years
Inflation rate	1.9%	Based on INL/RPT-22-66117 [2]

3.2.2 Financial Performance Outputs

The financial performance output with respect to the four cases defined in Cheng et al. [5] are shown in Table 3. Case 1 is a breakeven case where hydrogen market price is assumed to be the same as LCOH. Case 2 to Case 4 are market-defined cases where hydrogen market price is a user-defined value. Case 1 and Case 2 utilize the fixed electricity price from EIA websites at state of Luisiana in the year 2022. A fixed NG-correlated electricity price is used in Case 3, while a time-dependent NG-correlated electricity price is used in Case 4. Table 3 summarizes the LCOH before tax, IRR, NPV_{H2}, NPV_{BAU}, ΔNPV with and without PTC based on various hydrogen market, Natural Gas (NG), and electricity price. Note that NG price here is not a feedstock of the nuclear-integrated hydrogen production but used to calculate the correlated electricity price and LCOH from steam methane reforming (SMR) to compare with blue hydrogen production. Currently, only PTC for hydrogen production is considered and the PTCs for the electricity production will be incorporated into the analysis in the future.

Table 3. Financial performance outputs with respect to the four cases for NPP-HTSE with varied hydrogen market price. Electricity and natural gas prices are obtained from Table 3 (energy price by sector and sources) of annual energy outlook of the U.S. energy information administration (EIA).

Parameters	Case 1 (Breakeven)	Case 2 (Market-defined)	Case 3 (NG-Correlated electricity price)[a]	Case 4 (time-dependent electricity and NG price)
Hydrogen Market price ($2022)	$1.60/kg-$H_2$	$3.00/kg-$H_2$	$4.00/kg-$H_2$	$4.00/kg-$H_2$
Natural Gas price ($2022)	$6.54/MMBtu[b]	$6.54/MMBtu	$6.54/MMBtu	$7.33/MMBtu
Electricity Price ($2022)	$54.2/MWh[c]	$54.2/MWh	$80.13/MWh	$84.81/MWh
Outputs without PTC				
Levelized Cost of H_2 without PTC ($2022)	$3.58/kg-$H_2$	$3.58/kg-$H_2$	$4.67/kg-$H_2$	$4.10/kg-$H_2$
IRR	12.10%	59.08%	54.53%	67.74%
NPV_{H2}	0	1168 M	1092 M	1564 M
NPV_{BAU}	1491 M	1491 M	2205 M	1832 M
$\Delta NPV = NPV_{H2} - NPV_{BAU}$	-1491 M	-323 M	-1113 M	-269 M

[a] The correlation between electricity and NG price was constructed based on industrial price in Table 3 (energy price by sector and sources) of annual energy outlook (AEO) from U.S. energy information administration (EIA): https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=~ref2023-d020623a.19-3-AEO2023.1-0~ref2023-d020623a.23-3-AEO2023.1-0&map=ref2023-d020623a.3-3-AEO2023.1-0&ctype=linechart&sourcekey=0.

[b] The $6.54/MMBtu is calculated from $6.79/Thousand Cubic Feet based on the annual NG price data from EIA for Louisiana state at 2022: https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_SLA_a.htm.

[c] $54.2/MWh is obtained by the industrial electricity price at Luisiana state from EIA: https://www.eia.gov/state/data.php?sid=LA.

Parameters	Case 1 (Breakeven)	Case 2 (Market-defined)	Case 3 (NG-Correlated electricity price)[a]	Case 4 (time-dependent electricity and NG price)
Outputs with PTC				
Levelized Cost of H_2 with PTC ($2022)	$1.60/kg-$H_2$	$1.60/kg-$H_2$	$2.69/kg-$H_2$	$2.12/kg-$H_2$
IRR	76.40%	114.18%	108.11%	120.72%
NPV_{H2}	1647 M	2815 M	2739 M	3211 M
NPV_{BAU}	1491 M	1491 M	2205 M	1832 M
$\Delta NPV= NPV_{H2}-NPV_{BAU}$	156 M	1324 M	534 M	1379 M

From Table 3, although the IRR is greater or equals to WACC and NPV is greater than or equals to zero, the ΔNPV is negative for all the cases, the profits are not enough for operating an existing plant to produce hydrogen compared to selling the electricity to the grid. However, adding PTC of the hydrogen production enhances the NPV of hydrogen production significantly, resulting in the positive NPV for all the cases.

3.2.3 Sensitivity Analysis

The sensitivity study is performed for Case 2 based on the selected input parameters on the dashboard of NIHPA tool [5] including plant capacity, plant life, WACC, PTC, user-defined hydrogen market price and user-defined electricity price. The ranges of the upper and lower bounds are specified in Table 4.

Table 4. Lower, nominal, and upper bounds of the selected parameters for sensitivity study in Case 2.

Performance Metrics	Lower Bound	Nominal Value	Upper Bound	Note
HTSE plant capacity (MW-dc)	250	500	750	The upper bound and lower bounds are calculated by 50% of the nominal value from INL NPP-HTSE studies [9].
Plant Life (years)	7	20	26	7 years is selected as the lower bound based on the maximum stack service lifetime in INL NPP-HTSE studies [9]. 26 years is selected based on the constraint of the data from EIA AEO from 2022 to the year 2050 [11].
Weighted Average of Cost Capital (%)	11.50	12.10	12.71	A variation of 5% is assumed for WACC-based expert judgment
PTC ($/kg)	0	3.00	3.00	PTC is between zero to $3 per kilogram of hydrogen production based on IRA [12]
Hydrogen market price	0.50	3.00	5.00	Nominal value from 111 targets. Lower and upper bounds are specified based on internal discussion.

Performance Metrics	Lower Bound	Nominal Value	Upper Bound	Note
Electricity Price ($/MWh)	10.00	54.20	60.00	The upper bound and lower bounds are typical practice of the electricity cost for NPPs based on internal discussion.

Figure 1 shows the results of sensitivity study using the tornado charts, where the inputs are changed one at a time with respect to the output of interest (e.g., LOCH without PTC, and NPV_{H2} with PTC). For each tornado chart, the inputs are ranked based on the sensitivity for the inputs. For example, as shown in Figure 1 (a), electricity price is the most sensitive parameter for estimating LCOH while hydrogen market price is independent of the pre-tax LCOH estimation. In Figure 1 (b), hydrogen market price and PTC are the two most sensitive parameters for estimating NPV_{H2}.

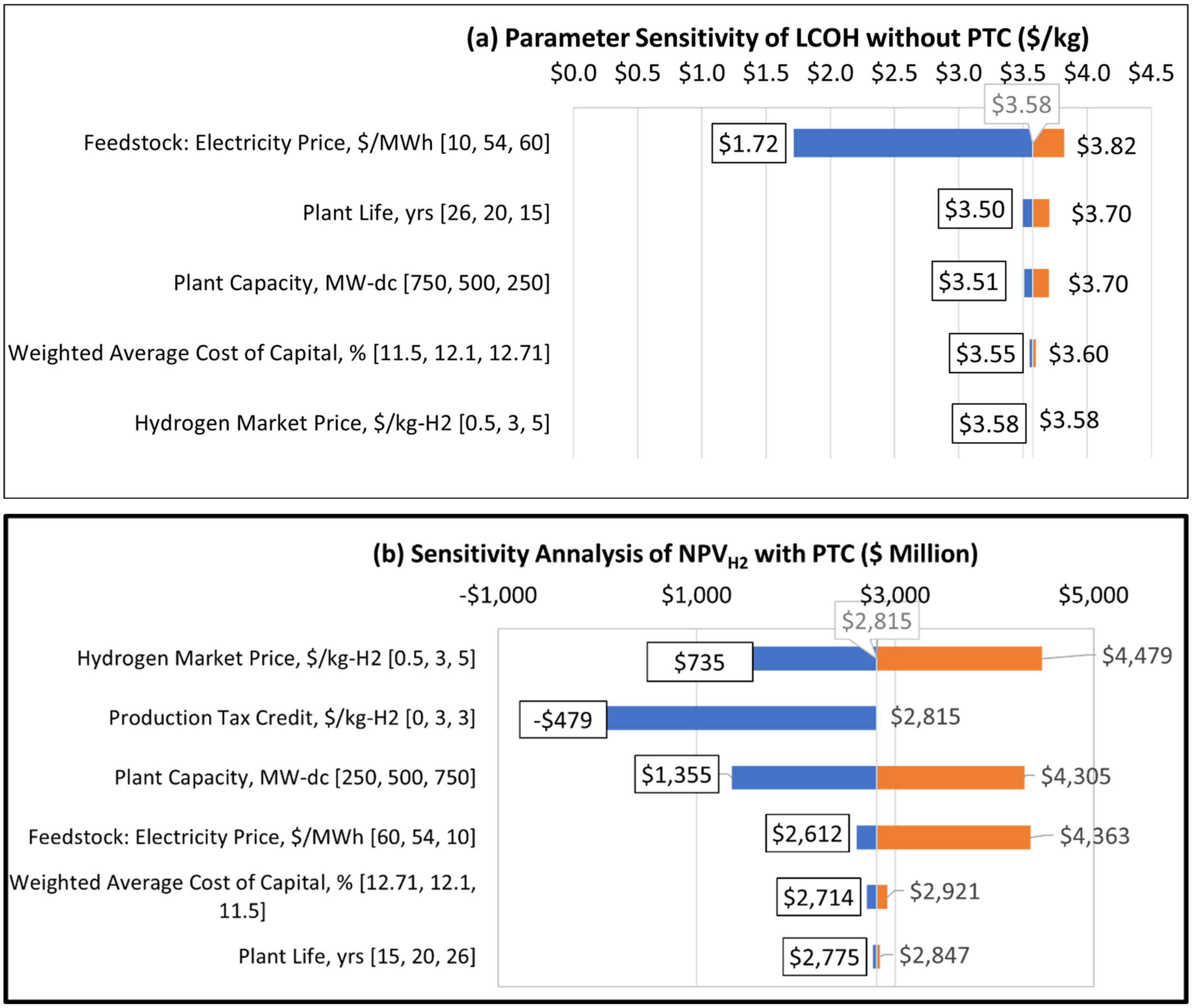
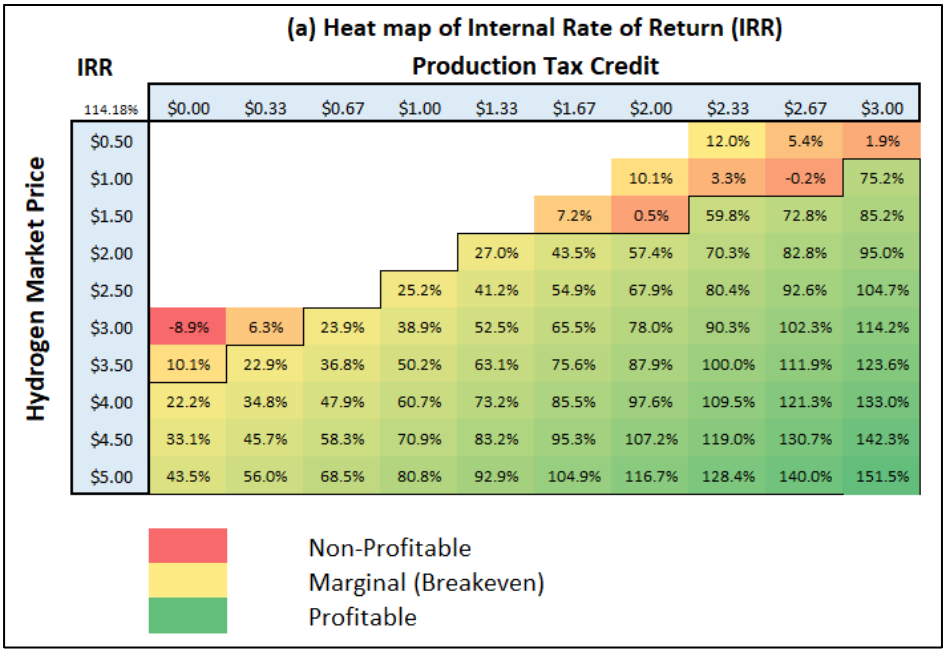


Figure 1. Sensitivity analysis for Case 2 with respect to (a) LCOH, and (b) NPV_{H2}.

3.2.4 Profitability Analysis

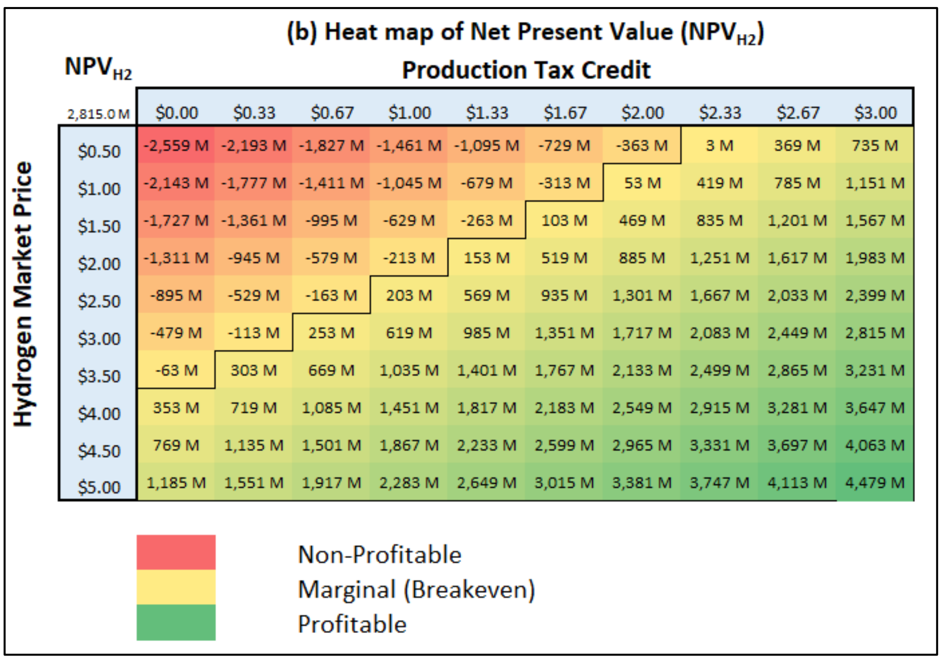
The profitability analysis is done in NIHPA tool by selecting the two most sensitive input parameters from sensitivity analysis.



(a) Heat map of Internal Rate of Return (IRR)

IRR — Production Tax Credit (columns) × Hydrogen Market Price (rows)

114.18%	$0.00	$0.33	$0.67	$1.00	$1.33	$1.67	$2.00	$2.33	$2.67	$3.00
$0.50								12.0%	5.4%	1.9%
$1.00							10.1%	3.3%	-0.2%	75.2%
$1.50						7.2%	0.5%	59.8%	72.8%	85.2%
$2.00					27.0%	43.5%	57.4%	70.3%	82.8%	95.0%
$2.50				25.2%	41.2%	54.9%	67.9%	80.4%	92.6%	104.7%
$3.00	-8.9%	6.3%	23.9%	38.9%	52.5%	65.5%	78.0%	90.3%	102.3%	114.2%
$3.50	10.1%	22.9%	36.8%	50.2%	63.1%	75.6%	87.9%	100.0%	111.9%	123.6%
$4.00	22.2%	34.8%	47.9%	60.7%	73.2%	85.5%	97.6%	109.5%	121.3%	133.0%
$4.50	33.1%	45.7%	58.3%	70.9%	83.2%	95.3%	107.2%	119.0%	130.7%	142.3%
$5.00	43.5%	56.0%	68.5%	80.8%	92.9%	104.9%	116.7%	128.4%	140.0%	151.5%



(b) Heat map of Net Present Value (NPV_{H2})

NPV_{H2} — Production Tax Credit (columns) × Hydrogen Market Price (rows)

2,815.0 M	$0.00	$0.33	$0.67	$1.00	$1.33	$1.67	$2.00	$2.33	$2.67	$3.00
$0.50	-2,559 M	-2,193 M	-1,827 M	-1,461 M	-1,095 M	-729 M	-363 M	3 M	369 M	735 M
$1.00	-2,143 M	-1,777 M	-1,411 M	-1,045 M	-679 M	-313 M	53 M	419 M	785 M	1,151 M
$1.50	-1,727 M	-1,361 M	-995 M	-629 M	-263 M	103 M	469 M	835 M	1,201 M	1,567 M
$2.00	-1,311 M	-945 M	-579 M	-213 M	153 M	519 M	885 M	1,251 M	1,617 M	1,983 M
$2.50	-895 M	-529 M	-163 M	203 M	569 M	935 M	1,301 M	1,667 M	2,033 M	2,399 M
$3.00	-479 M	-113 M	253 M	619 M	985 M	1,351 M	1,717 M	2,083 M	2,449 M	2,815 M
$3.50	-63 M	303 M	669 M	1,035 M	1,401 M	1,767 M	2,133 M	2,499 M	2,865 M	3,231 M
$4.00	353 M	719 M	1,085 M	1,451 M	1,817 M	2,183 M	2,549 M	2,915 M	3,281 M	3,647 M
$4.50	769 M	1,135 M	1,501 M	1,867 M	2,233 M	2,599 M	2,965 M	3,331 M	3,697 M	4,063 M
$5.00	1,185 M	1,551 M	1,917 M	2,283 M	2,649 M	3,015 M	3,381 M	3,747 M	4,113 M	4,479 M

Figure 2. Profitability analysis using heat maps for Case 2 with respect to (a) IRR, and (b) NPV_{H2}.

From Figure 2, the user should target on investing the hydrogen production when both IRR is greater than the WACC and NPV is positive as shown in the green color. Ideally, the higher the PTC and the hydrogen market price will result in a more profitable investment for hydrogen production. If the utilities who would like to invest the hydrogen production cannot get the full amount of the PTC (e.g., just $0.6 per hydrogen production), Figure 2 shows that hydrogen market price needs to be at least $3 per hydrogen production to have a profitable investment.

3.2.5 Preference Analysis

The preference analysis is done in NIHPA tool by comparing the NPV_{H2} and NPV_{BAU}. From Figure 3, the NPV_{BAU} is a function of electricity sale price, which is assumed to the same price representing the cost of the electricity from an NPP. The higher the electricity price, the higher the NPV_{BAU} since more revenue generated from selling electricity to the grid. The four dashed lines represent NPV_{H2} with different combinations of hydrogen market price and PTC. For each dashed line, the higher the electricity price, the lower the revenue since the electricity is a feedstock for the hydrogen production. A preferable region is formed by the boundaries of NPV_{BAU}, NPV_{H2}, and the x-axis, representing that the electricity price is zero. Within this region, it is preferred to generate hydrogen rather than selling electricity to the grid. In the case where electricity price is between \$10 to \$60 per MWh as specified in Table 4, producing hydrogen is always preferred.

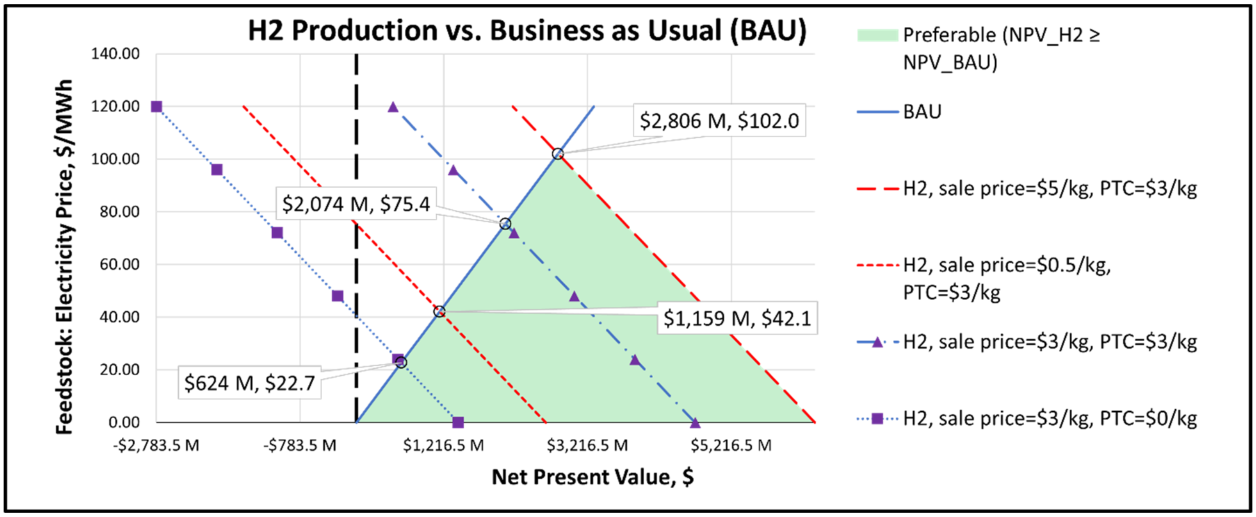


Figure 3. Hydrogen production profitability analysis for Case 2 with 500 MW-dc of HTSE design capacity, 20 years of plant life, 12.10% of WACC, user-defined electricity fixed price, user-defined hydrogen market price.

3.2.6 Competitive Analysis

The competitive analysis is done in NIHPA tool by comparing three major quantities: (1) LOCHs of nuclear-integrated hydrogen production with and without PTC, (2) LCOHs of SMR with and without carbon capture sequestration (CCS), and (3) user-defined hydrogen market price. The results of comparisons are shown in Figure 4, where part (a) represents the LCOHs with respect to NG price while part (b) shows the LCOHs with respect to electricity price.

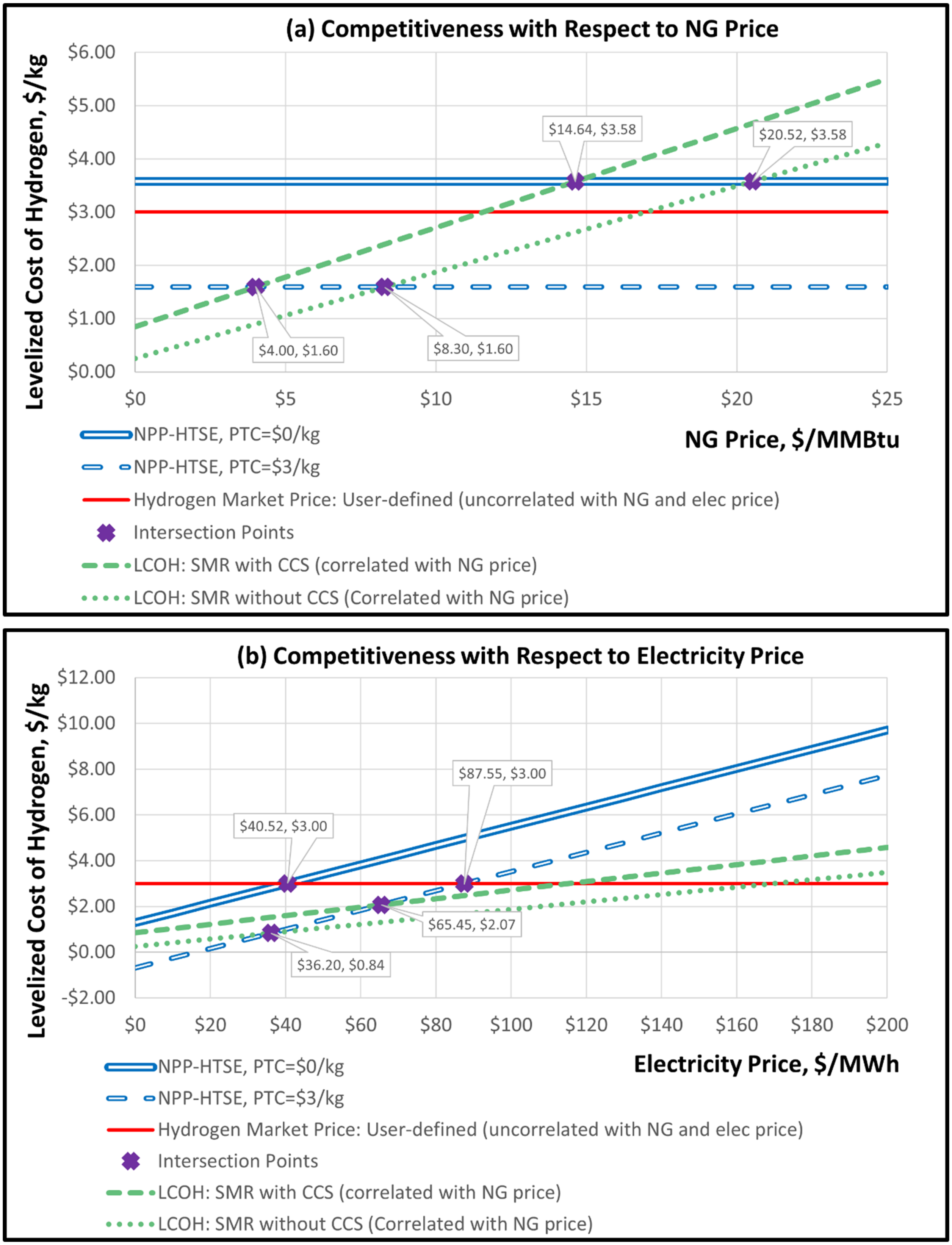


Figure 4. Competitive analysis for Case 2 with respect to (a) NG price, and (b) electricity price.

From Figure 4 (a), the LCOHs of nuclear-integrated hydrogen production (blue lines) and the user-defined hydrogen market price (red line) are independent of NG prices for Case 2 as consistent with the assumption, resulting in the horizontal lines. The LCOHs of SMR with and without CCS (green lines) are strongly dependent on the NG price. The intersection points shown in Figure 4 (a) indicates a competitive NG price with respect to different scenarios. For example, the intersection point formed by the lines representing the nuclear-integrated hydrogen production with PTC and SMR with CCS shows that the nuclear-integrated hydrogen production is competitive when NG price is above \$4 per MMBtu and the corresponding LCOH is \$1.6 per kilogram of hydrogen production. The similar observations can be made for the other intersection points in Figure 4 (a).

For Figure 4 (b), both the LCOHs of nuclear-integrated hydrogen production (blue lines) and the SMR (green lines) are dependent on the electricity price. However, the blue lines are steeper than the green lines considering that the nuclear-integrated hydrogen production requires more electricity than the SMR plant. The user-defined hydrogen market price (red line) is independent of NG prices for Case 2 as consistent with the assumption. The intersection points shown in Figure 4 (a) indicates a competitive electricity price with respect to different scenarios. For instance, the intersection point formed by the lines representing the nuclear-integrated hydrogen production with PTC and SMR with CCS shows that the nuclear-integrated hydrogen production is competitive when electricity price is below \$65.45 per MWh. This confirms that producing hydrogen using nuclear-integrated technology not only preferred but also competitive to the hydrogen production from SMR when the electricity price is in the range of \$10 to \$60 per MWh.

4. CONCLUSIONS

The analysis presented in this study of the market for future potential hydrogen demand from the Waterford Nuclear Generating Station, Riverbend Station, and Grand Gulf Nuclear Station has provided valuable insights into the varied demand centers within their respective regions. The investigation into demand centers for DRI, NG electricity generators, refineries, ammonia, and synthetic fuels, considering distances of 100 and 50 miles, revealed distinctive patterns for each NPP.

Ammonia production emerges as the primary consumer of hydrogen, particularly for Grand Gulf Nuclear Station and Riverbend Station, while DRI exhibits the smallest demand. Notably, the distribution of future potential hydrogen demand centers for Grand Gulf Nuclear Station and Riverbend Station predominantly lies within the 50 to 100-mile range, whereas for Waterford 3 Nuclear Generating Station, demand centers are concentrated within a 50-mile radius. Ammonia production is the largest consumer of hydrogen near Waterford, followed by refineries. It may be noted that for this NPP, more than half of the total hydrogen demand centers are located within 50 miles.

The TEA conducted for the Waterford 3 Nuclear Generating Station, utilizing the NIHPA tool, has yielded critical financial performance metrics. These include pre-tax LCOH, IRR, NPV for hydrogen production, Net Present Value for business as usual, and ΔNPV. Sensitivity analysis, focused on LCOH and NPV, underscored the significance of hydrogen market price and PTC as the most sensitive parameters affecting NPV.

The profitability analysis indicated that a minimum sale price of \$3 per kilogram of hydrogen would be necessary to ensure market competitiveness, especially in scenarios where only a partial tax credit (i.e., \$0.6 per kilogram hydrogen production) was obtained. Preference analysis revealed a preference for nuclear-integrated hydrogen production over selling electricity to the grid when electricity prices ranged from \$10 to \$60 per MWh.

In the realm of competitive analysis, it was determined that nuclear-integrated hydrogen production with a full PTC should be competitive with hydrogen production from SMR with CCS under specific conditions. This includes a NG price above \$4 per MMBtu or electricity prices below \$65.45 per MWh.

In essence, the findings from this comprehensive analysis provide a robust foundation for strategic decision-making regarding hydrogen production at the Waterford 3 Nuclear Generating Station, offering insights into the economic viability and competitiveness of nuclear-integrated hydrogen production in the evolving energy landscape.

In summary,

- Analysis of market for future potential hydrogen demand from Waterford Nuclear Generating Station, Riverbend Station, and Grand Gulf Nuclear Station was carried out.
- Demand centers for DRI, NG electricity generators, refineries, ammonia, and synthetic fuels for these NPPs within 50 to 100 miles was investigated.
- Ammonia is expected to be the largest consumer of the hydrogen for those NPPs investigated thus far.
- The majority of the future potential hydrogen demand centers for Grand Gulf Nuclear Station and Riverbend Station are located within 50 to 100 miles whereas for Waterford 3 Nuclear Generating Station, the demand centers lie within 50 miles.
- TEA was done for Waterford 3 Nuclear Generating Station using the NIHPA tool.
- TEA results showed the financial performance metrics including pre-tax LCOH, IRR, NPV for hydrogen production, Net present value for business as usual, and ΔNPV, sensitivity analysis with respect to LCOH and NPV, profitability analysis, preference analysis, and competitive analysis.
- The sensitivity analysis showed that the hydrogen market price and PTC are the most sensitive parameters with respect to NPV of nuclear-integrated hydrogen production.
- The profitability analysis showed that a selling price of at least $3 per kilogram of hydrogen would be required if only a partial tax credit (i.e., $0.6 per kilogram hydrogen production) were obtained.
- The preference analysis showed that nuclear-integrated hydrogen production was preferred compared to selling the required electricity to the grid when the electricity price was in the range of $10 to $60 per MWh.
- The competitive analysis showed that the nuclear-integrated hydrogen production with the full PTC should be competitive with hydrogen production from SMR with CCS if the NG price was above $4 per MMBtu or the electricity price is below $65.45 per MWh.

4.1 Future Work

Future work includes:

- Conduct similar market and hydrogen production analysis as well as other potential markets for NPP heat and electricity in the Gulf Coast region.
- Include the PTC for the electricity generation from an NPP in a BAU case and the tax credits for the hydrogen production from SMR with CCS.
- Include the comparisons of nuclear-integrated hydrogen production via HTSE and LTE.
- Expand the application of the NIHPA tool to LTE and to BWRs.
- Expand the application of the tool to other sites in the Gulf Coast Area.

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[12] *Inflation Reduction Act, H.R. 5376, 117th Cong. (the Act) § 13204,* 2022.

Appendix A

Future Potential Hydrogen Market Analysis

Table A-1. Future potential hydrogen demand (MT/day) within 100 miles of Riverbend Station.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
St Francisville Mill: Hood Container of Louisiana, LLC	NG Electricity Generators	5	7
Big Cajun 2: Louisiana Generating LLC	NG Electricity Generators	16	9
Big Cajun 1: Louisiana Generating LLC	NG Electricity Generators	3	12
Georgia-Pacific Port Hudson: Georgia-Pacific Cons Op LLC Port Hudson	NG Electricity Generators	7	13
Exxon Mobil Corp, Baton Rouge	Refinery	535	25
ExxonMobil Baton Rouge Turbine Generator: Exxon Mobil Corp	NG Electricity Generators	15	26
Louisiana 1: Entergy Louisiana LLC	NG Electricity Generators	41	26
Formosa Plastics: Formosa Plastics Corp	NG Electricity Generators	8	26
Placid Oil Co, Port Allen	Refinery	80	29
Port Allen (LA): Placid Refining Co LLC	NG Electricity Generators	1	29
LSU Cogen: LSU and A&M College	NG Electricity Generators	2	31
Plaquemine Cogeneration Plant: Dow Chemical Co	NG Electricity Generators	92	41
LaO Energy Systems: Dow Chemical Co	NG Electricity Generators	18	41
Alon Israel Oil Company Ltd, Krotz Springs	Refinery	85	41
Axiall Plaquemine: Axiall Corp	NG Electricity Generators	38	47
Eurochem, Edgard	Ammonia	430	51
Nutrien, Geismar	Ammonia	260	53
Carville Energy LLC: Carville Energy LLC	NG Electricity Generators	52	53
Geismar Cogen: Air Liquide Large Industries U.S. LP	NG Electricity Generators	12	53
Shell Chemical: Air Liquide America Corp	NG Electricity Generators	17	54

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Geismar: BASF Corporation	NG Electricity Generators	15	54
Burnside Alumina Plant: Almatis Burnside Inc.	NG Electricity Generators	6	58
Motiva Enterprises LLC, Convent	Refinery	242	60
Cf Industries, Donaldsonville	Ammonia	1868	66
Louisiana Sugar Refining: Louisiana Sugar Refining LLC	NG Electricity Generators	4	72
Gramercy Holdings LLC: Gramercy Holdings LLC	NG Electricity Generators	24	72
Marathon Petroleum Corp, Garyville	Refinery	578	76
T J Labbe Electric Generating: Lafayette Utilities System	NG Electricity Generators	0.46	83
Acadia Energy Center: Cleco Power LLC	NG Electricity Generators	72	84
Bayou Steel Group	DRI	4	85
Coughlin Power Station: Cleco Power LLC	NG Electricity Generators	37	88
Hargis-Hebert Electric Generating: Lafayette Utilities System	NG Electricity Generators	1	89
Am Agrigen, Killona	Ammonia	216	89
Little Gypsy: Entergy Louisiana LLC	NG Electricity Generators	50	89
Motiva Enterprises LLC, Norco	Refinery	240	90
Waterford 1 & 2: Entergy Louisiana LLC	NG Electricity Generators	19	91
Valero Energy Corp, Norco	Refinery	229	91
Taft Cogeneration Facility: Occidental Chemical Corporation	NG Electricity Generators	83	92
LEPA Unit No. 1: Louisiana Energy & Power Authority	NG Electricity Generators	4	93
Dow St Charles Operations: Dow Chemical Co - St Charles	NG Electricity Generators	50	94
D G Hunter: City of Alexandria - (LA)	NG Electricity Generators	3	100
Royal Dutch/Shell Group, Saint Rose	Refinery	48	100

Table A-2. Future potential hydrogen demand (MT/day) within 100 miles of Grand Gulf Nuclear Station.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Baxter Wilson: Entergy Mississippi Inc	NG Electricity Generators	14	22
Ergon Biofuels LLC, Vicksburg	Syngas: Ethanol	55	31
Ergon Refining Vicksburg: Ergon Refining Inc	NG Electricity Generators	1	31
Ergon Inc, Vicksburg	Refinery	28	32
International Paper Vicksburg Mill: International Paper Co-Vicksbg	NG Electricity Generators	4	42
Rex Brown: Entergy Mississippi Inc	NG Electricity Generators	4	67
Hinds Energy Facility: Entergy Mississippi Inc	NG Electricity Generators	45	68
Mississippi Baptist Medical Center: Mississippi Baptist Medical	NG Electricity Generators	0.139	73
Nucor Steel - Jackson Inc.	DRI	4	74
Yazoo: Public Serv Comm of Yazoo City	NG Electricity Generators	0.005	74
Cf Industries, Yazoo City	Ammonia	249	79
CF Industries Yazoo City Complex: CF Industries Nitrogen LLC	NG Electricity Generators	4	79
Georgia-Pacific Monticello Paper: Georgia-Pacific Monticello LLC	NG Electricity Generators	4	94

Table A-3. Future potential hydrogen demand (MT/day) within 100 miles of Waterford NPP.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Waterford 1 & 2: Entergy Louisiana LLC	NG Electricity Generators	19	1
Taft Cogeneration Facility: Occidental Chemical Corporation	NG Electricity Generators	83	1
Dow St Charles Operations: Dow Chemical Co - St Charles	NG Electricity Generators	50	2
Am Agrigen, Killona	Ammonia	216	2
Royal Dutch/Shell Group, Saint Rose	Refinery	48	15
Dyno Nobel, Waggaman	Ammonia	400	16
Motiva Enterprises LLC, Norco	Refinery	240	17

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Valero Energy Corp, Norco	Refinery	229	18
Gramercy Holdings LLC: Gramercy Holdings LLC	NG Electricity Generators	24	22
Louisiana Sugar Refining: Louisiana Sugar Refining LLC	NG Electricity Generators	4	23
Bayou Steel Group	DRI	4	26
Little Gypsy: Entergy Louisiana LLC	NG Electricity Generators	50	27
Nine Mile Point: Entergy Louisiana LLC	NG Electricity Generators	157	27
Marathon Petroleum Corp, Garyville	Refinery	578	28
Domino Sugar Arabi Plant: American Sugar Refining Inc.	NG Electricity Generators	4	38
Cf Industries, Donaldsonville	Ammonia	1868	39
Motiva Enterprises LLC, Convent	Refinery	242	39
Pbf Energy Co LLC, Chalmette	Refinery	202	39
Burnside Alumina Plant: Almatis Burnside Inc.	NG Electricity Generators	6	39
Houma: Terrebonne Parish Consol Gov't	NG Electricity Generators	1	41
Valero Energy Corp, Meraux	Refinery	133	41
Geismar Cogen: Air Liquide Large Industries U.S. LP	NG Electricity Generators	12	43
Shell Chemical: Air Liquide America Corp	NG Electricity Generators	17	44
Geismar: BASF Corporation	NG Electricity Generators	15	44
Oak Point Cogen: Chevron Oronite Co LLC	NG Electricity Generators	4	46
Nutrien, Geismar	Ammonia	260	48
Carville Energy LLC: Carville Energy LLC	NG Electricity Generators	52	49
Phillips 66 Company, Belle Chasse	Refinery	263	56
Alliance Refinery: Phillips 66	NG Electricity Generators	0.17	56
Axiall Plaquemine: Axiall Corp	NG Electricity Generators	38	57
Eurochem, Edgard	Ammonia	430	58

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
LaO Energy Systems: Dow Chemical Co	NG Electricity Generators	18	62
Plaquemine Cogeneration Plant: Dow Chemical Co	NG Electricity Generators	92	62
LSU Cogen: LSU and A&M College	NG Electricity Generators	2	63
Exxon Mobil Corp, Baton Rouge	Refinery	535	67
Port Allen (LA): Placid Refining Co LLC	NG Electricity Generators	1	67
Placid Oil Co, Port Allen	Refinery	80	67
LEPA Unit No. 1: Louisiana Energy & Power Authority	NG Electricity Generators	4	67
Louisiana 1: Entergy Louisiana LLC	NG Electricity Generators	41	69
ExxonMobil Baton Rouge Turbine Generator: Exxon Mobil Corp	NG Electricity Generators	15	69
Formosa Plastics: Formosa Plastics Corp	NG Electricity Generators	8	69
Georgia-Pacific Port Hudson: Georgia-Pacific Cons Op LLC Port Hudson	NG Electricity Generators	7	82
Gaylord Container Bogalusa: Temple-Inland Corp	NG Electricity Generators	2	88
Big Cajun 1: Louisiana Generating LLC	NG Electricity Generators	3	88
Grand Isle Gas Plant	NG Electricity Generators	0	92
Big Cajun 2: Louisiana Generating LLC	NG Electricity Generators	16	93
Teche: Cleco Power LLC	NG Electricity Generators	17	94
Buras: Entergy Louisiana LLC	NG Electricity Generators	0.17	94
St Francisville Mill: Hood Container of Louisiana, LLC	NG Electricity Generators	5	98