JISEA Joint Institute for Strategic Energy Analysis

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Mark Ruth, Dylan Cutler,
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National Renewable Energy Laboratory

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Technical Report
NREL/TP-6A50-66764
April 2017

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Preface

The generation and use of energy in the electricity, buildings, industrial, and transportation sectors is continuously evolving. These changes are being driven by economics and by environmental and energy security concerns. The electricity-sector-market share of natural gas and variable-generation renewables, such as wind and solar photovoltaics (PV), continues to grow. The buildings sector is evolving and becoming more efficient, the transportation sector is becoming more efficient and technologically diverse with the introduction of renewable fuel standards and policies, and the industrial sector is evolving to reduce emissions through efficiency improvements, advanced combined heat and power (CHP), and increased energy storage.[1] These drivers and others for energy resiliency and security motivate investment and utilization strategies for innovative energy generation and delivery assets.

Nuclear and renewable energy sources are important to consider in the U.S. economy's evolution because neither energy source emits carbon nor emits sulfur oxides, nitrogen oxides, or particulates. The Idaho National Laboratory (INL) and the Joint Institute for Strategic Energy Analysis (JISEA) are jointly investigating potential synergies between nuclear and renewable energy technologies. A series of workshops since 2011 have brought together experts and stakeholders in both areas to identify collaboration opportunities and develop research plans to analyze and evaluate the cost-benefits and technical development needs of nuclear renewable energy beyond the electrical power market. Workshop participants identified nuclear-renewable hybrid energy systems (N-R HESs) as one of the potential opportunities and recommended investigating whether N-R HESs could both generate dispatchable electricity without carbon emissions and provide clean energy to industrial processes. The participants also recommended analyzing the potential for N-R HESs to provide dispatchable capacity to the grid and investigate whether real inertia provided by thermal power cycles within N-R HESs provides value to the grid.

Several categories of N-R HESs have been identified. Tightly coupled N-R HESs are co-located; directly integrated via electrical, thermal, or both forms of energy; and co-controlled behind the grid (i.e., they have a single connection to the grid). Thermally coupled N-R HESs have an integrated thermal connection and are co-controlled but might have multiple electrical connections to the grid and subsystems might not be co-located. Loosely coupled, electricity-only N-R HESs only have electrical interfaces and subsystems that can be located separately with multiple connections to the grid, but they are co-controlled so a single management entity dispatches the energy and services they provide to the grid.

This report is one in a series of reports that INL and JISEA are publishing that address the technical and economic aspects of N-R HESs. This report discusses an analysis of the economic potential of a tightly coupled N-R HES that produces electricity and hydrogen. Both low and high temperature electrolysis options are considered in the analysis. Low temperature electrolysis requires only electricity to convert water to hydrogen. High temperature electrolysis requires less electricity because it uses both electricity and heat to provide the energy necessary to electrolyze water.

Previous reports focused on tightly coupled N-R HESs. Two N-R HES case studies were initially analyzed by INL to evaluate their dynamic performance characteristics.[2] Subsequently, JISEA team researchers conducted an assessment of optimal economic configurations and operation of similar N-R HESs.[3] These case studies are based on a future condition when wind or PV is producing a significant fraction of power generation and a new small/modular nuclear power plant that apportions heat between power production and a heat user is added to the grid. The first case study involves the production of methanol from natural gas with nuclear energy shifting between providing heat for methanol production and power production that ramps up and down, corresponding to wind power generation and grid demand dynamics. The second case study involves operation of a brackish water desalination plant when the combination of nuclear and solar power generation exceeds grid demand. JISEA researchers also analyzed the economic potential of N-R HESs that provide thermal energy for industrial processes.[4]

The joint analyses found that nuclear plants can effectively modulate heat between power production and heat use by an industrial consumer and that the optimal financial pro forma occurs when the nuclear reactor is mainly supplying heat to industry. The nuclear reactor may switch to power generation if capacity payments for power production are adequate. These outcomes demonstrate that nuclear and renewable energy can fulfill power generation and thermal duties of the grid and industrial heat users in a complementary manner, but hybridization will depend on the future cost of natural gas power production and clean energy investment and production incentives.

INL and JISEA performed another analysis that quantifies greenhouse gas (GHG) emissions from the industrial sector and identifies opportunities for non-GHG-emitting thermal energy sources to replace the most significant GHG-emitting U.S. industries based on targeted, process-level analysis of industrial heat requirements.[5] That work's intent was to provide a basis for projecting opportunities for clean energy use, especially for small modular nuclear reactors (including N-R HES), solar industrial process heat, and geothermal energy.

Acknowledgments

The authors thank the Office for Advanced Reactor Technology within the U.S. Department of Energy's (DOE's) Office of Nuclear Energy (NE) and the Office of Strategic Programs within DOE's Office of Energy Efficiency and Renewable Energy (EERE) for their support of this analysis and report. The authors also thank those who originated and developed the concept of nuclear-renewable hybrid energy systems, including Charles Forsberg of the Massachusetts Institute of Technology (MIT); Humberto Garcia and Steven Aumeier of Idaho National Laboratory (INL); and Owen Zinaman of the National Renewable Energy Laboratory (NREL). We acknowledge and thank the following individuals for their reviews and comments: Sunita Satyapal, Fred Joseck, Stephen Capanna, and Paul Spitsen (EERE); Carl Sink (NE); Richard Boardman (INL); Doug Arent of the Joint Institute for Strategic Energy Analysis (JISEA); and Gian Porro, Bryan Pivovar, and Keith Wipke (NREL).

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List of Acronyms

AEO	Annual Energy Outlook
capex	capital expenditure
CHP	combined heat and power
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Agency
EPA	U.S. Environmental Protection Agency
FIRE	Firebrick Resistance Heated Energy Storage
GHG	greenhouse gas
GT	gas turbine
H_2	hydrogen
H2A	Hydrogen Analysis model (U.S. Department of Energy)
HES	hybrid energy system
HTE	high temperature electrolysis
INL	Idaho National Laboratory
IRR	internal rate of return
kW	kilowatt
kWe	kilowatt electric
kWhe	kilowatt-hour electric
kWht	kilowatt-hour thermal
kWt	kilowatt thermal
kW-yr	kilowatt year
LTE	low temperature electrolysis
LW-SMR	light water small modular reactor
MWe	megawatt electrical
MWh	megawatt-hour
MWt	megawatt thermal
NGCC	natural gas combined cycle
NPV	net present value
NO_x	nitrogen oxides
N-R HES	nuclear-renewable hybrid energy system
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PEM	polymer electrolyte membrane
Psig	pounds per square inch - gauge
PV	photovoltaics
RE	renewable electricity generation
REopt	Renewable Energy Optimization (planning platform)
RPS	renewable portfolio standard
SMR	small modular reactor
SO_x	sulfur oxides
TCI	total capital investment

Executive Summary

Context and Background

The generation and use of energy in the electricity, buildings, industrial, and transportation sectors is continuously evolving. The market share of natural gas and variable renewables, such as wind and solar photovoltaics (PV), in the electricity sector continues to grow. The buildings sector is evolving and becoming more efficient, the transportation sector is becoming more efficient and technologically diverse with the introduction of renewable fuel standards and policies, and the industrial sector is continuing energy efficiency improvements, advancing combined heat and power (CHP), and increasing energy storage.[6] These drivers and others for energy resiliency and security motivate investment and utilization strategies for innovative energy generation and delivery assets.

Tightly coupled nuclear-renewable hybrid energy systems (N-R HESs) are a technology solution that can generate dispatchable electricity and provide hydrogen (or other fuels) potentially with fewer emissions (carbon dioxide, sulfur oxide, nitrogen oxide, and particulate emissions), lower use of fossil energy resources (natural gas, oil, and coal), and beneficial economic impacts (higher capacity factors, domestic production of energy). N-R HESs are defined as systems that are managed by a single entity and link a nuclear reactor that generates heat, a thermal power cycle for heat-to-electricity conversion, at least one renewable energy source, and an industrial process that uses thermal and/or electrical energy. Hybrid configurations produce at least two products from multiple energy sources and control the product split to maximize profit. Because that control provides flexibility, N-R HESs are potentially advantageous over traditional technologies that produce a single product and use a minimal number of energy sources.

In this report, we analyze N-R HESs using two different hydrogen production technologies. We chose hydrogen as the industrial product in this analysis for four reasons: (1) stakeholders expressed interest in hydrogen as an industrial product from N-R HESs;[7] (2) hydrogen produced via electrolysis of very low-priced electricity is a key aspect of the H2@Scale Big Idea;[*] (3) hydrogen is a potential energy carrier that both the transportation and industrial sectors can use while reducing emissions of air pollutants such as SO_x, NO_x, and particulates; and (4) hydrogen has been proposed as a means to provide long-duration, seasonal energy storage for electricity and other uses. The first hydrogen production technology we analyze is high temperature electrolysis (HTE) and the second is low temperature electrolysis (LTE). LTE requires only electricity to convert water to hydrogen. HTE requires less electricity because it uses both electricity and heat to provide the energy necessary to electrolyze water. This analysis builds upon our earlier analysis of two N-R HES case studies: one with a nuclear reactor, thermal power cycle, wind power plant, and synthetic gasoline production technology in Texas and a second with a nuclear reactor, thermal power cycle, PV, and a desalination plant in Arizona.[8] This work also builds upon our analysis of N-R HES options that produce thermal energy for industry.[9]

[*] The H2@Scale Big Idea is a concept proposed by a coordinated team of 14 U.S. Department of Energy (DOE) national laboratories at the DOE's Lab Big Idea Summit in Washington, D.C.

Approach and Assumptions

We analyzed the financial performance of three N-R HES scenarios based on the HTE and LTE technologies. Each N-R HES scenario has the potential to generate electricity for the grid and produce hydrogen. To perform the analysis, we modified the Texas N-R HES in Ruth et al. (2016)[10] by removing its industrial process and adding an electrolyzer subsystem. The first scenario is the HTE scenario that includes a high temperature electrolyzer that utilizes heat from a nuclear reactor and electricity from the thermal power cycle, a wind power plant, and/or the grid. The second and third scenarios use LTE where the low temperature electrolyzers utilize electricity only. That electricity could be from thermal power cycle, the wind power plant, and/or the grid. The difference between the two LTE scenarios is the electrolyzer's capital cost and efficiency. In scenario #2, we used projected low temperature electrolyzer costs and efficiencies. In scenario #3, we reduced the electrolyzer's cost and its efficiency.

We tested four hypotheses on each of the first two scenarios:

1. The N-R HES configurations analyzed have the potential to be profitable to investors and are likely to be more profitable than uncoupled configurations.
2. Hydrogen generated by an N-R HES can economically reduce greenhouse gas (GHG) emissions from hydrogen production compared to steam methane reforming. We also analyzed the impact of a cost of carbon on the relative economics.
3. N-R HESs can support resource adequacy for the electricity grid while maximizing production of an alternative product (hydrogen) if market structures incentivize that option.
4. N-R HESs will be more profitable than uncoupled configurations because they can produce electricity when its price is high and hydrogen when the price of electricity is low.

We also tested a fifth hypothesis using the two LTE scenarios:

5. If research and development can lead to LTE with a lower capital cost, even if the efficiency is compromised, then N-R HESs with LTE will be more profitable and more likely to switch between electricity and hydrogen products.

To test the hypotheses, we performed a number of runs for each scenario under a variety of electricity and hydrogen price combinations. For each run, we determined the most profitable configuration (which subsystems are optimally included and which are not) and the operational strategy (how and when each subsystem is operated to maximize profit). Table ES-1 reports the different electricity price sets that we used. Each electricity price set consists of wholesale electrical energy and ancillary service (contingency, regulation, and flexibility reserves) prices for each hour during a year. Runs based on the primary electricity price set included those both without and with a cost of carbon, and included exploration of several levels of capacity payments ($50/kW-yr, $100/kW-yr, $150/kW-yr). Runs using a volatile electricity price set did not include a cost of carbon and were based on capacity payment of $50/kW-yr. For each scenario and electricity price set, we calculated a reference case using the electricity price set and the minimum price for steam reforming of natural gas to produce hydrogen ($1.47/kg for most runs and $2.20/kg for the runs with a $61/ton CO_2e cost of carbon). The primary driver of this minimum price is the price of natural gas, assumed to be \$6.98/mmBtu, based on the Energy Information Administration's *Annual Energy Outlook 2015* projection for 2035.[11] Because the prices of electricity and the hydrogen product are very uncertain, we assessed sensitivities to the reference case prices each scenario and electricity price set. We performed the electricity price sensitivities by multiplying the electrical energy prices by a multiplier during all hours of the year to retain the shape of the hourly price profiles (the reference case electricity prices have a multiplier of 1.0). For each electricity price set considered for each scenario, at least 1,000 different combinations of electricity price and hydrogen price were assessed.

Table ES-1. Hydrogen-Producing HES Analysis Scenario Design

Scenario (Hydrogen Production Technology)	Primary Electricity Price Set	Primary Electricity Price Set with Cost of Carbon	Primary Electricity Price Set with Various Capacity Payments	Volatile Electricity Price Set
High Temperature Electrolysis (HTE) Subsystem	X	X	X	X
Low Temperature Electrolysis (LTE) Subsystem	X	X	X	X
Low Temperature Electrolysis (LTE) Subsystem with Low Capital Cost Electrolyzer	X	X	Not Analyzed	X

X indicates electricity price conditions analyzed.

The primary electricity price set was used for previous N-R HES analyses, including Ruth et al. (2016).[12] It is based on the 2036 generation mix from a National Renewable Portfolio Standard (RPS) scenario (one of the 19 Standard Scenarios that NREL analyzes annually),[13] which leads to 80% renewably generated electricity in 2050. In this scenario, wind generators produce 21% and PV systems produce 20% of the annual electricity generation. The remaining generation includes natural gas combined cycle (NGCC) generators (26% of the annual electricity generation), hydropower (26% of the annual electricity generation), traditional nuclear power that produces electricity exclusively (6% of the annual electricity generation), and natural gas combustion turbines (about 1% of the annual electricity generation). Because the NGCC and combustion turbine generators are flexible with high ramp rates, short minimum up and down times, and low restart costs, the resulting electricity prices are not as volatile as they would be in the absence of the flexible generators. We also assumed that the grid is not transmission constrained (i.e., there is sufficient transmission available). The volatile electricity price set is from an analysis of high renewable penetration in California, Denholm et al. (2016),[14] with potentially 8.6% of the total electricity demand served by wind power and 37% served by solar (PV and concentrating solar power). Due to the high penetrations of wind and solar and some transmission congestion, some generation is expected to be curtailed resulting in California-located wind generation meeting 4.4% of the California load and California-located solar meeting 21% of the California load. Total curtailment is estimated at 12% of the California load. Other generators in California and the estimated percent of the load they meet are nuclear (6%);

NGCC and natural gas combustion turbines (22%); combined heat and power (8%); biomass (3%); and geothermal (7%). Coal generation meets less than 1% of the California load. In addition, the production cost model estimates that under the generation mix California imports 14% of its annual load. The volatile electricity price set has 2,246 hours per year when the marginal price of electricity is $0/MWh and 213 hours per year when the electricity price is above $100/MWh whereas the primary electricity price set has only 704 hours per year at $0/MWh and 40 hours per year at $100/MWh. Further, the volatile electricity price set has fewer hours with electricity prices between $50/MWh and $60/MWh.

Capital and operating costs for the nuclear reactor, thermal power cycle, and wind power plants, come from other published analyses.[15]

The HTE and LTE subsystems' capital and operating costs are based on the H2A case studies developed by the Department of Energy's Fuel Cells Technology Office.[16] The HTE subsystem's purchase cost is $430/kWe and its total capital cost is $662/kWe.[17] Operating costs are from the same source. The HTE subsystem requires 35.1 kWhe electricity and 11.15 kWht thermal energy per kilogram of hydrogen produced.[18] In the LTE scenario based on projected costs, the LTE subsystem's purchase cost is $400/kWe and its total capital cost is $616/kWe.[19] The LTE subsystem requires 50.2 kWhe electricity per kilogram of hydrogen produced.[20] Operating costs are from the same source.

To explore hypothesis #5, we included a third scenario that involves a potential LTE subsystem with a low capital cost. Its purchase cost is $100/kWe and its total capital cost is $154/kWe. We increased the low capital cost LTE subsystem's electricity use to 55.2 kWhe per kg of hydrogen produced based on the H2@Scale team's estimate.[21]

We used a consistent set of financial assumptions for all configurations in all three scenarios: 100% equity, a 10% nominal discount rate, a 3% inflation rate, and startup in 2035. These assumptions, based on Short (1996),[22] are consistent with those used in the previous N-R HES analyses published by the Joint Institute for Strategic Energy Analysis (JISEA).[23] These financial parameters result in a nominal weighted average cost of capital of 10%, which can be met at various debt/equity ratios with different discount rates. We assessed profitability for each configuration by calculating net present value (NPV) of cash flows over a 25-year project financial life considering revenues generated through sales of electricity and hydrogen and expenses incurred for system installation, system operation and maintenance, and fuel purchases. Positive NPVs (equivalent to a 10% nominal rate of return) are considered profitable.

Findings

Our analysis yielded the following outcomes related to each hypothesis explored:

Our analysis results partially support hypothesis #1. Under reference case prices (electricity multiplier of 1.0, hydrogen price of $1.47/kg), none of the configurations we considered for all three scenarios are profitable. The primary reason for this outcome is that the reference case hydrogen and electricity prices are low compared to the N-R HES's projected production costs—too low to meet the capital and operating costs. However, we identified opportunities where both LTE and HTE N-R HESs may be profitable when electricity prices are high, natural gas prices are high, or a cost of carbon is included.

Figures ES-1 and ES-2 show the combinations of hydrogen prices and electricity price multipliers where HTE and projected cost LTE N-R HESs meet the profitability test. To generate both figures, we varied the hydrogen price from \$0/kg to \$10/kg and the electricity price multiplier from 0 to 2.0 and identified the most profitable configuration (set of subsystems) and associated operational strategy for each specific configuration. The graph on the left of each figure reports the results for the primary electricity price set and the graph on the right reports the results for the volatile electricity price set. The colored dots identify configurations that are profitable and each color represents the specific set of subsystems in that configuration as defined in the legends. The black dots indicate the reference electricity price multiplier of 1.0 and hydrogen price of \$1.47/kg.

At high electricity price multipliers and low hydrogen prices, maximizing electricity production maximized profit so the optimal configuration is the nuclear reactor, thermal power cycle, and wind power plant, as indicated by the orange dots in each figure. Electrolyzers are not included in the optimal configuration at those combinations because they would replace electricity sales with lower-value hydrogen sales or require electricity purchases to produce the lower-value hydrogen product.

At high hydrogen prices and low electricity price multipliers, hydrogen production dominates so the optimal configurations include the electrolyzers. In the HTE N-R HES scenario under the primary electricity price set, the nuclear reactor is also included in the optimal configuration under those combinations because the nuclear reactor is necessary to produce heat for the electrolyzer, as shown by the yellow dots. Sometimes, the ability to switch between electricity and hydrogen production warrants inclusion of the thermal power cycle, as shown by the purple dots. That value occurs more often under the volatile electricity price set. In the LTE N-R HES scenario, nuclear heat is not necessary for the electrolyzer so the only subsystem in the optimal configuration under those conditions is the low temperature electrolyzer (as indicated by the yellow dots in Figure ES-2).

At both high hydrogen prices and high electricity price multipliers, the full configurations—including the nuclear reactors, thermal power cycles, wind power plants, and electrolyzers—are optimal and the system adjusts to the most valuable product during each hour of the year (as indicated by the pink dots in each figure).

For both the HTE and LTE N-R HES, the volatile price set results in more combinations of electricity price multipliers and hydrogen prices where the optimal N-R HES meets the profitability test. This result indicates that N-R HESs are more likely to be profitable where electricity prices are more volatile.

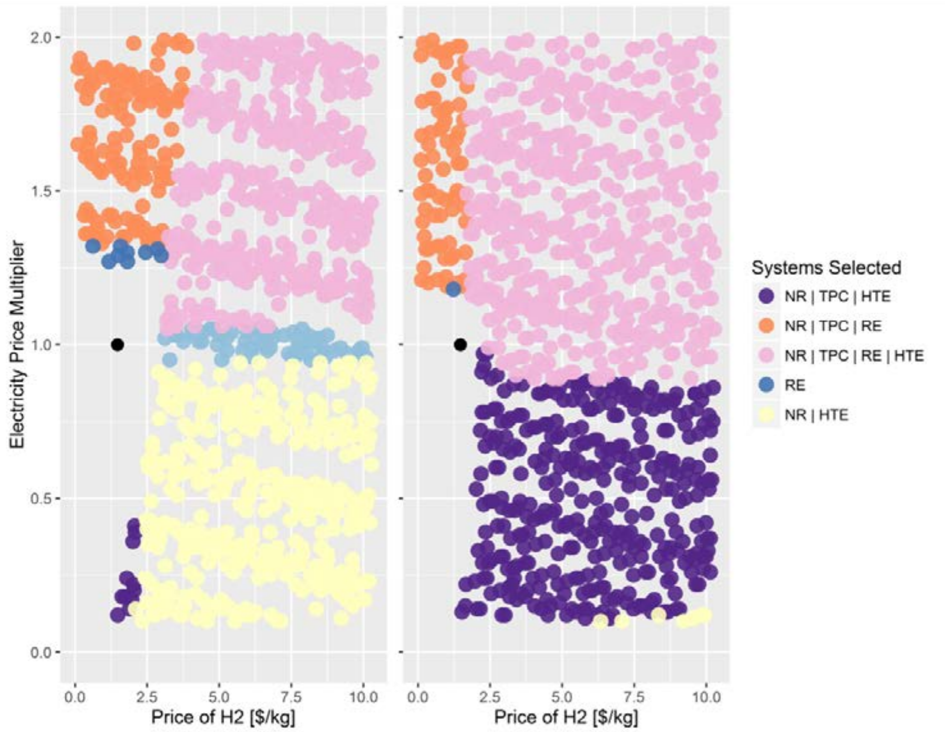

Figure ES-1. Optimal configurations for the HTE scenario with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

HTE: high temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

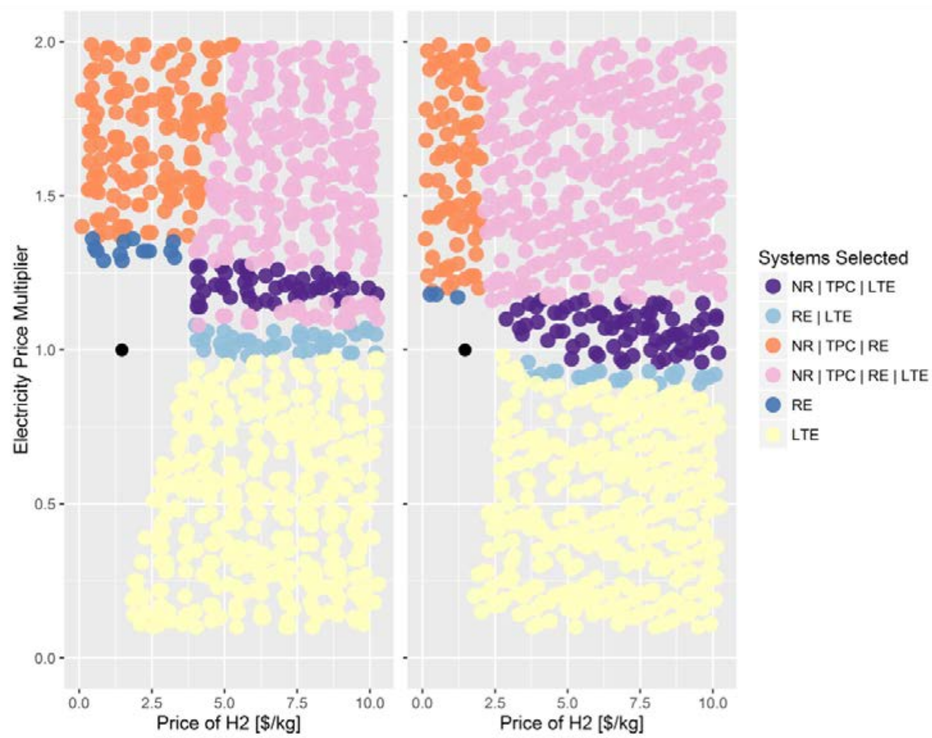

Figure ES-2. Optimal configurations for the projected cost LTE scenario with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Our analysis findings indicate that high carbon costs or resource limitations are required to support hypothesis #2. None of the HTE or LTE (standard capital cost) configurations were profitable at reference case conditions, even when a cost of carbon of $61/metric ton CO_2e was added to the price of electricity and to hydrogen generated from natural gas. A higher cost of carbon would be needed to make the configurations profitable at reference case prices.

This conclusion stands even though the reference case price for hydrogen is increased from $1.47/kg H_2 to $2.20/kg H_2 to account for the cost for carbon dioxide emitted in the steam methane reforming process. None of the HTE or LTE (standard capital cost) N-R HES configurations tested under the primary electricity price set can sell hydrogen at that price while meeting the required 10% nominal discount rate unless the electricity price multiplier is greater than 1.05.

Other policy and societal drivers could potentially increase that required hydrogen price to a point where the N-R HES configurations analyzed here would be profitable. Examples of such drivers could include a societal cap on natural gas use, a clean hydrogen standard, or a limitation on the use of natural gas production technologies, such as fracking, that would limit natural gas supply.

Our analysis results do not support hypothesis #3. None of the HTE or LTE (projected capital cost) configurations are profitable at reference case conditions, even at capacity payments up to $150/kW-yr. Increased capacity payments reduce the hydrogen prices and electricity price multipliers necessary for the N-R HESs to be profitable and thus to support grid resource adequacy; however, under the primary set of electricity prices, capacity payments higher than $150/kW-yr are necessary for the N-R HESs analyzed to be profitable at reference case prices. We did not test the impact of capacity payments under a more volatile set of electricity prices.

Our analysis findings partially support hypothesis #4. Under volatile electricity price conditions, N-R HESs have a higher NPV than uncoupled configurations because they can produce electricity when the price of electricity is high and hydrogen when the price is low. The primary electricity price set does not have enough volatility for either the HTE or LTE (projected capital cost) configuration to produce hydrogen optimally during any hours of the year at reference case prices. The volatile electricity price set has enough volatility that the LTE N-R HES (projected capital cost) configuration with the nuclear reactor, thermal power cycle, and LTE optimally produces 3,149 metric tons of hydrogen annually, although the NPV of that configuration is still more negative than the configuration only the nuclear reactor and thermal power cycle. Likewise, the full HTE N-R HES configuration optimally produces 4,719 metric tons of hydrogen annually, but its NPV is still more negative than the configuration with only the nuclear reactor and thermal power cycle. Hence, under volatile prices, flexibility of configurations that can produce both hydrogen and other products is valuable but not valuable enough to overcome the increased capital cost.

Our analysis results support hypothesis #5. Under the primary electricity price set at the reference case prices, an LTE N-R HES with an electrolyzer with a lower capital cost and reduced efficiency is not profitable and is unlikely to switch between electricity and hydrogen products. However, as Figure ES-3 shows, under the volatile electricity price set, this low capital cost configuration is profitable at lower hydrogen prices and electricity price multipliers than the standard capital cost LTE. The graph on the left side of the figure shows standard capital cost LTE configurations that meet the profitability test and the graph on the right side shows the same information for the low capital cost LTE. Since there are more configurations that meet the profitability test with the low capital cost LTE, the benefits of HES output flexibility are potentially more often realized if the electrolyzer's capital cost is lower even if the efficiency is also reduced.

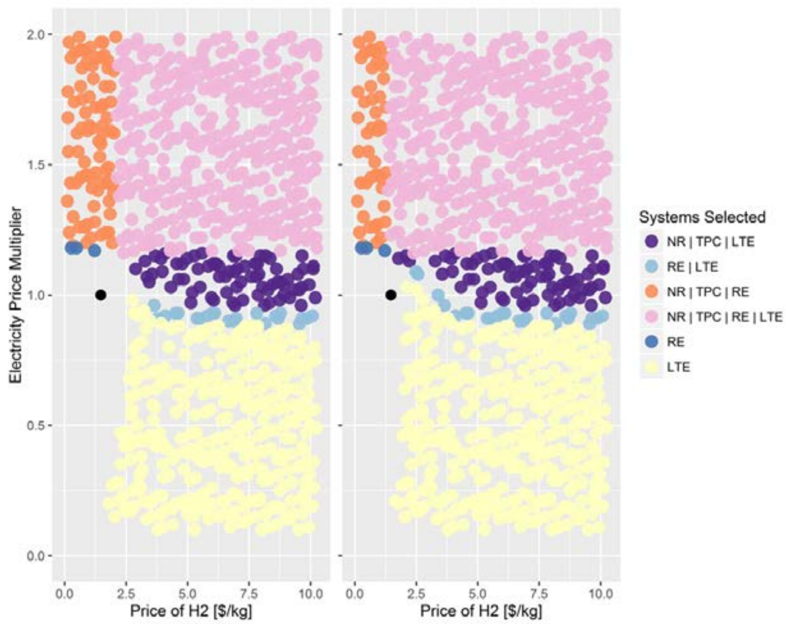

Figure ES-3. Optimal configurations for the LTE scenario under the volatile electricity price set with reference electrolyzer parameters (left) and the low-cost electrolyzer parameters (right)

$50/kW-yr capacity payments
LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle

In conclusion, to be profitable, the examined HTE and LTE N-R HES configurations that produce hydrogen require higher electricity prices, more electricity price volatility, higher natural gas prices, or higher capacity payments than the reference case values of these parameters considered in this analysis. Electricity prices could be higher if generation options are more limited than considered in this analysis. Natural gas prices could be higher if gas supply is more constrained or greater carbon emissions penalties exist than considered in this analysis. In addition, these N-R HESs show more combinations of electricity price multipliers and hydrogen prices with profitable configurations under the volatile electricity price set than under the primary electricity price set. Electricity prices could be more volatile if the grid is transmission-constrained or if the mix of generators on the grid is less flexible than assumed.

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1 Introduction

Nuclear-renewable hybrid energy systems (N-R HESs) have the potential to generate dispatchable, very low-carbon electricity without emitting sulfur oxides, nitrogen oxides, or particulates while simultaneously providing very low-carbon thermal energy to industry without emitting other pollutants. N-R HESs might be able to provide both forms of energy at a lower cost than alternatives.[24] N-R HESs are defined as co-managed systems that link a nuclear reactor that generates heat, a thermal power cycle for heat-to-electricity conversion, at least one renewable energy source, and an industrial process that uses thermal and/or electrical energy. As co-managed systems, N-R HESs are operated as if they are owned by a single entity; thus, they have a common objective that is usually overall profit. These hybrid configurations differ from traditional technologies that use a minimal number of energy sources to produce a single product.[25] In this report, the N-R HESs that we analyze produce hydrogen as their industrial product.

N-R HESs can provide a number of potential societal benefits:[26]

1. Dispatchable, flexible, zero-pollutant, and very low-carbon electricity generation that can support adequate resources on the grid
2. Reduced greenhouse gas (GHG), sulfur oxide, nitrogen oxide, and particulate emissions in the industrial sector
3. Synchronous electro-mechanical (real) inertia that supports the grid
4. Alleviation of the impacts of electricity price suppression at high penetration of low marginal cost generation (e.g., nuclear and renewables).

All subsystems in the tightly coupled N-R HESs analyzed in this report are directly coupled behind a single electrical bus or connection to the grid. In other words, the subsystems are connected directly instead of having connections through external means (e.g., the grid). A single financial entity is responsible for investment and operational decisions of the full N-R HES so one subsystem may take a small loss to improve the overall economics.

Previously, we estimated the financial performance of three types of tightly coupled N-R HESs. In one report, we analyzed the potential of an N-R HES with a nuclear reactor, thermal power cycle, wind power plant, and synthetic gasoline production technology in Texas. In that report, we also analyzed the potential of a second N-R HES that included a nuclear reactor, thermal power cycle, photovoltaic (PV) solar power plant, and a desalination plant in Arizona.[27] In a subsequent report, we focused on an N-R HES that produces thermal energy for an independent customer or set of customers (e.g., an industrial park).[28]

In this study, we investigated the potential of an N-R HES that can produce hydrogen for industrial or transportation use. We analyzed an N-R HES with a nuclear reactor, thermal power cycle, wind power plant, and electrolyzer located in Texas. We investigated two scenarios: one with low temperature electrolysis (LTE) that uses electricity as the only energy source to convert water to hydrogen and oxygen and a second with high temperature electrolysis (HTE) that use both water and heat as energy sources for the conversion. We also included the options to use wind and grid electricity for the electrolyzers.

We chose hydrogen as the industrial product in this analysis for four reasons. First, stakeholders expressed interest in hydrogen as an industrial product from N-R HESs.[29] Second, hydrogen produced via electrolysis of very low-priced electricity is a key aspect of the H2@Scale Big Idea.[30] The Big Idea is predicated upon hydrogen generation enabling increased penetrations of variable renewable electricity generation such as wind and solar by providing an energy load when generation exceeds load. The Big Idea also involves use of the low-cost hydrogen in the transportation and industrial sectors and as a supplement to the natural gas system. Third, hydrogen is a potential energy carrier that both the transportation and industrial sectors can use while reducing emissions of air pollutants such as sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates. Finally, we chose hydrogen for this analysis because it has been proposed as a means to provide electricity storage across seasons.[31] Seasonal storage is likely to be needed at high penetrations of variable renewable electricity generation because the difference between generation potential and load is much greater in the spring and fall than in the summer and winter. In addition, use of domestic resources to produce hydrogen potentially increases the quantity and quality of domestic jobs.

In the remainder of this section, we describe the analysis objectives and the two N-R HESs that we examined.

1.1 Analysis Objectives

This analysis focuses on the benefits of N-R HESs and compares those benefits with independent systems. The objective is to determine whether the benefits outweigh the increased costs and complexity. Our primary focus is value to the investors, but we also considered the value of N-R HESs to society. We did not evaluate impacts on markets (e.g., ability to support increased penetrations of variable renewable electricity generation) or evolutionary aspects such as investment drivers and timing of decisions.

We tested four hypotheses on each of the first two scenarios:

1. The N-R HES configurations analyzed have the potential to be profitable to investors and are likely to be more profitable than uncoupled configurations.
2. Hydrogen generated by an N-R HES can economically reduce greenhouse gas (GHG) emissions from hydrogen production compared to steam methane reforming. We also analyze the impact of a cost of carbon on the relative economics.
3. N-R HESs can support resource adequacy for the electricity grid while maximizing production of an alternative product (hydrogen) if market structures incentivize that option.
4. N-R HESs will be more profitable than uncoupled configurations because they can produce electricity when its price is high and hydrogen when the price of electricity is low.

We also tested a fifth hypothesis using the two LTE scenarios:

5. If research and development can lead to LTE with a lower capital cost, even if the efficiency is compromised, then N-R HESs with LTE will be more profitable and more likely to switch between electricity and hydrogen products.

The first hypothesis focuses on value to investors because, if there is no value for investors under projected futures, the technology is unlikely to be built and will not affect the grid or benefit society. If there is value to investors, especially if that value is great, construction of many units is likely and, if that happens, competition will likely also drive down the price of the electricity and hydrogen products—benefiting society by providing lower-cost energy carriers. We did not create a pricing strategy that allocates costs between the electricity and hydrogen products because such a strategy is highly uncertain.

The second and third hypotheses provide some insight on societal impacts. We compared the GHG emissions from N-R HESs to those from hydrogen production from natural gas and monetized those impacts using a cost of carbon. That comparison provides insights into whether monetizing the impact of emissions will make non-emitting production options economically competitive. For the third hypothesis, we did not explicitly model resource adequacy; however, we included capacity payments to address it.

The fourth hypothesis analyzes the source of profitability by exploring potential benefits of the N-R HESs' flexibility to shift between products due to the variability in electricity prices.

The fifth hypothesis focuses on tradeoffs between capital cost and efficiency. One scenario includes projected LTE costs and the other is based on a lower capital cost electrolyzer that may have a higher return due to the ability to use low-cost electricity for a smaller number of hours annually.[32]

1.2 Nuclear-Renewable Hybrid Energy Systems Analyzed

N-R HESs are systems managed by a single entity that link a nuclear reactor that generates heat, a thermal power cycle for heat-to-electricity conversion, at least one renewable energy source, and an industrial process that uses thermal and/or electrical energy.[33] For this analysis, the industrial product is hydrogen. We analyzed two options for producing that hydrogen: (1) HTE that uses both electricity and heat from the nuclear reactor and (2) LTE that uses electricity exclusively. To perform the analysis, we adapted the Texas N-R HES that we analyzed previously.[34] We removed the natural-gas-to-synthetic-gasoline subsystem and replaced it with hydrogen production. In addition, we included an option to purchase electricity from the grid as in the prior study.[35]

Figure 1 shows the HTE scenario's full configuration. For the HTE scenario, we identified the optimal configuration from seven options under various electricity price vectors and hydrogen prices:

1. The nuclear reactor and thermal power cycle produce electricity only.
2. The wind power plant produces electricity only.
3. Both the nuclear reactor/thermal power cycle and the wind power plant produce electricity exclusively.
4. The nuclear reactor produces thermal energy for HTE. There is no thermal power cycle to convert any of the nuclear heat to electricity. Grid power provides electricity for HTE.

5. The nuclear reactor produces thermal energy for HTE. There is no thermal power cycle to convert any of the nuclear heat to electricity. Wind and grid power provide electricity for HTE.
6. The nuclear reactor produces thermal energy that is used by both the thermal power cycle and HTE, and the N-R HES produces hydrogen with or without electricity. Electricity can be purchased from the grid to supplement hydrogen production.
7. The nuclear reactor produces thermal energy that is used by both the thermal power cycle and HTE, and the N-R HES produces hydrogen with or without electricity. The wind plant produces electricity for the grid and HTE. Electricity can be purchased from the grid to supplement hydrogen production.

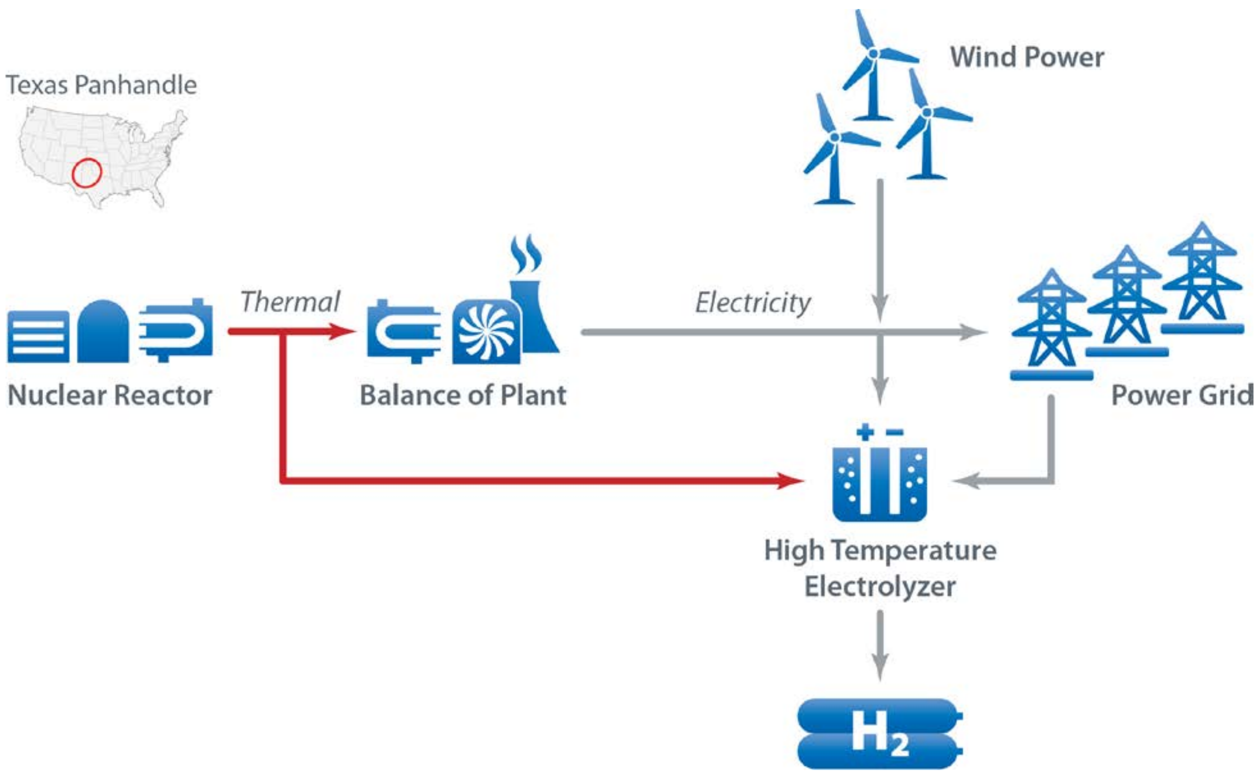

Figure 1. N-R HES HTE scenario

Electricity for HTE can be sourced from the nuclear reactor/thermal power cycle, the wind power plant, and/or the grid. Heat can only be sourced from the nuclear reactor.

Red arrows indicate flow of thermal energy and gray arrows indicate electricity.

Two LTE scenarios are analyzed. Figure 2 shows the full configuration for both of them. In both scenarios, we used a low temperature electrolyzer that uses only electricity to produce hydrogen from water.

For the LTE scenario, we identified the optimal configuration from six options under various electricity price vectors and thermal energy prices:

1. The nuclear reactor and thermal power cycle produce electricity only.
2. The wind power plant produces electricity only.

3. Both the nuclear reactor/thermal power cycle and the wind power plant produce electricity exclusively.
4. The nuclear reactor/thermal power cycle produces electricity for the LTE and possibly the grid.
5. The wind power plant produces electricity for the LTE and possibly the grid, and the LTE potentially uses grid electricity.
6. The nuclear reactor/thermal power cycle and the wind power plant produce electricity, and the LTE uses a portion (or possibly all) of that electricity and could potentially use grid electricity as well. This is the full N-R HES configuration for this scenario.

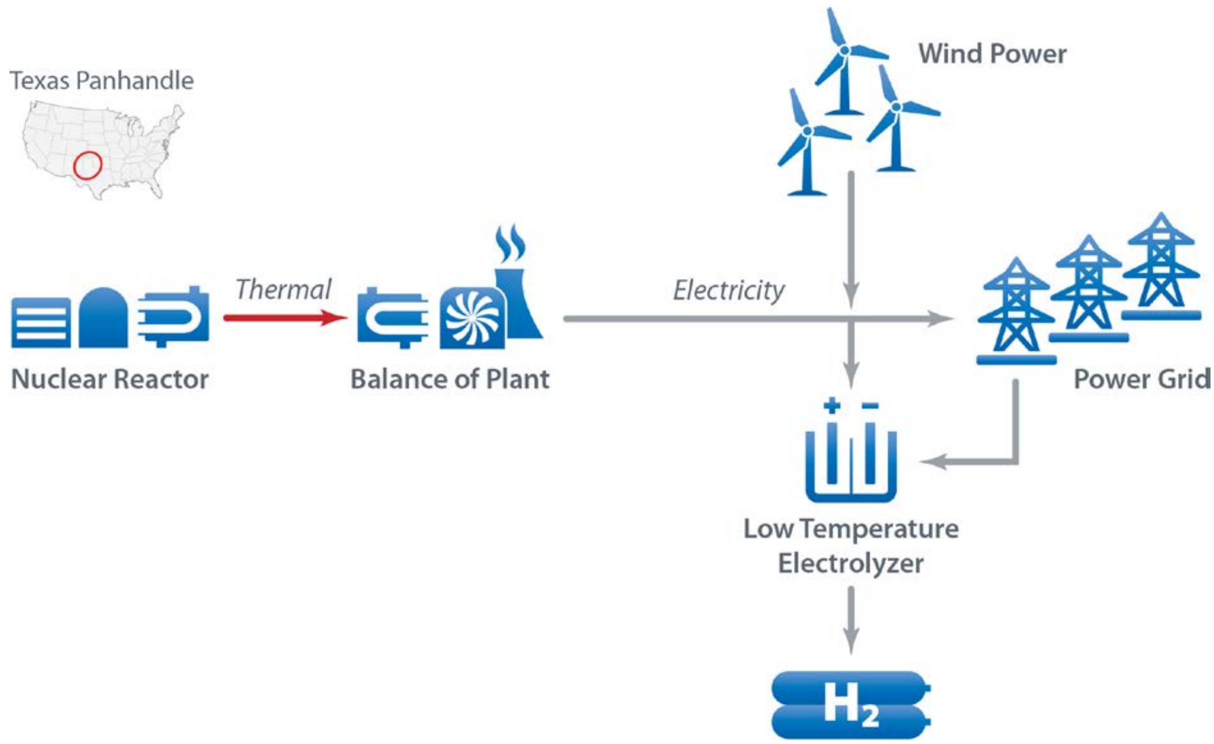

Figure 2. N-R HES LTE scenario

Electricity for LTE can be sourced from the nuclear reactor/thermal power cycle, the wind power plant, and/or the grid.

Red arrows indicate flow of thermal energy and gray arrows indicate electricity.

The difference between the two LTE scenarios is the projected cost and efficiency of the low temperature electrolyzer. One LTE scenario involves the projected capital cost for the electrolyzer and the other involves a low capital cost electrolyzer that also has a reduced efficiency. Those differences are described in Section 2.4.

2 Analysis Methodology and Parameters

This section summarizes the methodology used to perform the analysis and provides details and references for key parameters that differ from previous analyses. The information provided in this section is intended for others performing similar analyses or comparing results from this analysis to their own.

Most of the key parameters in this analysis are identical to those used in Ruth et al. (2016a)[36] or Ruth et al. (2016b).[37] Instead of discussing those parameters in detail in this report, we refer the reader to those reports.

The subsections within this section discuss the basis and methodology used to estimate the Renewable Energy Optimization (REopt) tool inputs that differ from the previous analyses—Ruth et al. (2016a)[38] or Ruth et al. (2016b).[39] Details about the methodology used for the annual cash flow calculation can be found in Ruth et al. (2016a).[40] There are seven subsections. The first subsection outlines the methodology used to perform the analysis. The second subsection discusses the electrical energy and ancillary service prices used. The third subsection discusses the capacity payments used for the electricity market. The fourth subsection reports the capital and operating cost estimates used in this analysis. The fifth subsection states the financial assumptions. The sixth subsection discusses the costs of carbon used in this analysis. The final subsection reports a cost of natural-gas-generated hydrogen that is used as a comparison in this analysis.

2.1 Analysis Methodology

We performed our analysis by optimizing subsystem sizes and operational decisions (internal dispatch strategy) to maximize the profitability over each of the N-R HES scenarios described in Section 1. We performed the optimization of each N-R HES under a variety of electricity price vectors and hydrogen prices. That process allowed us to determine the most profitable configuration under each scenario so that we understand the drivers that affect configuration selection and operational decisions. We optimized for and expressed profit as net present value (NPV).

To perform the optimization, we used the National Renewable Energy Laboratory's (NREL's) REopt tool for the optimization. REopt is an energy-planning platform that offers concurrent, multiple technology integration and optimization capabilities. Formulated as a mixed-integer linear program, REopt identifies optimal subsystem sizes and dispatch strategies for the selected technologies. The model accounts for subsystem costs (capital, fixed, and variable), fuel costs, financial parameters (discount rate, inflation, utility price escalation rates, and incentives), utility prices, and other variables that contribute to a techno-economic analysis of the proposed system. REopt also has the capability to optimize a system for objectives other than those used in this analysis, such as minimum fuel consumption or minimum GHG emissions.[41]

To optimize profitability, REopt calculates an annual cash flow for each option. REopt requires a number of inputs to perform the optimization on subsystem size and hourly operations. The key inputs are:

- Electricity energy prices for both sales and purchasing

- Electricity ancillary service prices for sales
- Electricity capacity payments and requirements to receive the payments
- Hydrogen price
- Capital and operating costs for each subsystem (the subsystems are the nuclear reactor, the thermal power cycle, the wind power plant, and the electrolyzer).

With those inputs, we used REopt to identify the subsystem capacities and hourly dispatch that maximize the NPV of the N-R HES for the scenario under the electricity price vector and the hydrogen price. All subsystems were allowed to vary in size from no capacity (i.e., not present) to a maximum capacity of 50 megawatts electrical (MWe) (167 megawatts thermal [MWt] in the case of the nuclear reactor). At its maximum size, the HTE unit requires both 50 MWe and 16.4 MWt. Using both 50 MWe and 16.4 MWt, the HTE subsystem can produce approximately 1,420 kilograms of hydrogen per hour (kg H_2/hr).

We kept maximum sizes of each subsystem constant because the purpose of the analysis is to understand the potential of coupled subsystems with full flexibility. Subsystem optimization and subsystem inclusion would be unclear if we constrained subsystem capacities such that the minimum capacity of one or more subsystems was greater than zero, requiring its presence in the optimal configuration. The same may be true if we constrained the maximum capacity of one subsystem to less than that of another subsystem, allowing the first subsystem to produce more energy than the second subsystem can use.

We performed post-processing outside REopt to estimate the potential impacts of various costs of carbon and to develop comparisons to hydrogen production using a steam methane reformer.

As in the previous efforts, we estimated the economic incentive for the N-R HES to address the ability of the N-R HESs analyzed to support the grid's resource adequacy requirements at several capacity payments.[42] We defined support of resource adequacy as the situations when the optimal configuration receives capacity payments as income and the N-R HES would provide the power required to receive those payments. We defined the lack of support of resource adequacy as situations when the optimal configuration does not receive capacity payments.

We employed the same set of fundamental assumptions as in the previous analysis.[43] The analysis methodology is for a greenfield (all new) plant because that methodology results in more general results instead of fitting a specific set of conditions. We report results in 2013 dollars and that was the cost year for the entire analysis, although we used energy price projections to 2035. Light water small modular reactors (L-W SMR) were the type of nuclear reactor used within this analysis.

2.2 Electrical Energy and Ancillary Service Price Estimates

We used the same electricity prices as in the previous analysis; details regarding our methodology can be found in Ruth et al. (2016a).[44] We modified the methodology for Ruth et al. (2016b) to allow the N-R HES to purchase electricity at a price slightly higher than the marginal cost.[45] This section provides a general description of the methodology used to estimate those electricity prices.

Three types of electricity products were included in the analysis (note that the N-R HES can also receive revenue by selling hydrogen):

1. Electrical energy revenue (dollars per megawatt-hour [$/MWh])
2. Ancillary service revenue from contingency reserves, regulation, and flexibility reserves
3. Capacity payments (dollars per kilowatt-year [$/kW-yr]).

We use two sets of electricity prices in this analysis. In the first, generation mixes are based on three regions from standard scenario national results developed at NREL. The results presented here are based on the 2036 generation mix in NREL's National Renewable Portfolio Standard (RPS) scenario. That scenario is one of the 19 Standard Scenarios that NREL analyzes annually. [46] It is the one that leads to 80% renewably generated electricity in 2050. Because the standard scenario modeling results are only calculated for even-numbered years, results for the year 2035 are not available. Hence, 2036 results are considered sufficient as the generator mix for the year 2035 for this effort. Results for 2036 are used in this analysis as they were in the previous two analyses. In this case, wind generators produce 21% and PV produces 20% of the annual electricity generation. The remaining generation includes natural gas combined cycle (NGCC) generators (26% of the annual electricity generation), hydropower (26% of the annual electricity generation), traditional nuclear power that only produces electricity (6% of the annual electricity generation), and natural gas combustion turbines (about 1% of the annual electricity generation). Much of the capacity that is assumed to retire between now and 2036 is replaced by natural gas combined cycle (NGCC) generators. Those modern generators are flexible with high ramp rates, short minimum up and down times, and low restart costs. If the generation mix does not have that level of flexibility, prices are likely to be more volatile,. We used the PLEXOS production cost model used with the 2036 National RPS generation mix to estimate the annual electrical energy production and hourly electrical energy and ancillary service prices as reported in Ruth et al. (2016a) to develop the standard electricity price set.[47] Hourly electrical energy and ancillary reserve prices are those paid by the load. Prices of resources such as coal, natural gas, and oil match the 2035 reference case prices reported in the U.S. Energy Information Administration's 2015 Annual Energy Outlook (AEO) and are consistent with our previous analyses.[48] In the AEO, the projected natural gas price in 2035 is $6.98/mmBtu. Electrical energy and ancillary service prices are derived from the short-run marginal costs of the marginal generator and do not include markups or any sort of scarcity pricing. Figure 3 shows the cost duration curve. The marginal price of electricity is $0/MWh during 704 hours per year (hr/yr). Prices are capped at $100/MW and the cap was reached primarily during reserves violations—situations in which optimization software found it less expensive to the grid to short the reserves slightly rather than start or shutdown a generator. Electricity energy prices are at the $100/MW cap during 40 hr/yr. In the PLEXOS simulation, we assumed that the grid is not transmission constrained (i.e., there is sufficient transmission available). If the grid has insufficient transmission, energy and reserve prices may be more volatile and vary more between nodes resulting in locations where electrolysis may be more profitable and the N-R HES's flexibility more valuable.

For sensitivities with a cost of carbon, we used a cost of carbon of $61/metric ton (as discussed in Section 2.6) to increase operating costs of electricity generation for carbon-emitting generation technologies. We then used the PLEXOS production cost model to estimate hourly electrical energy and ancillary service prices with the cost of carbon. Note that we did not adjust the generation mix due to the cost of carbon. Figure 3 shows the resulting cost duration curve.

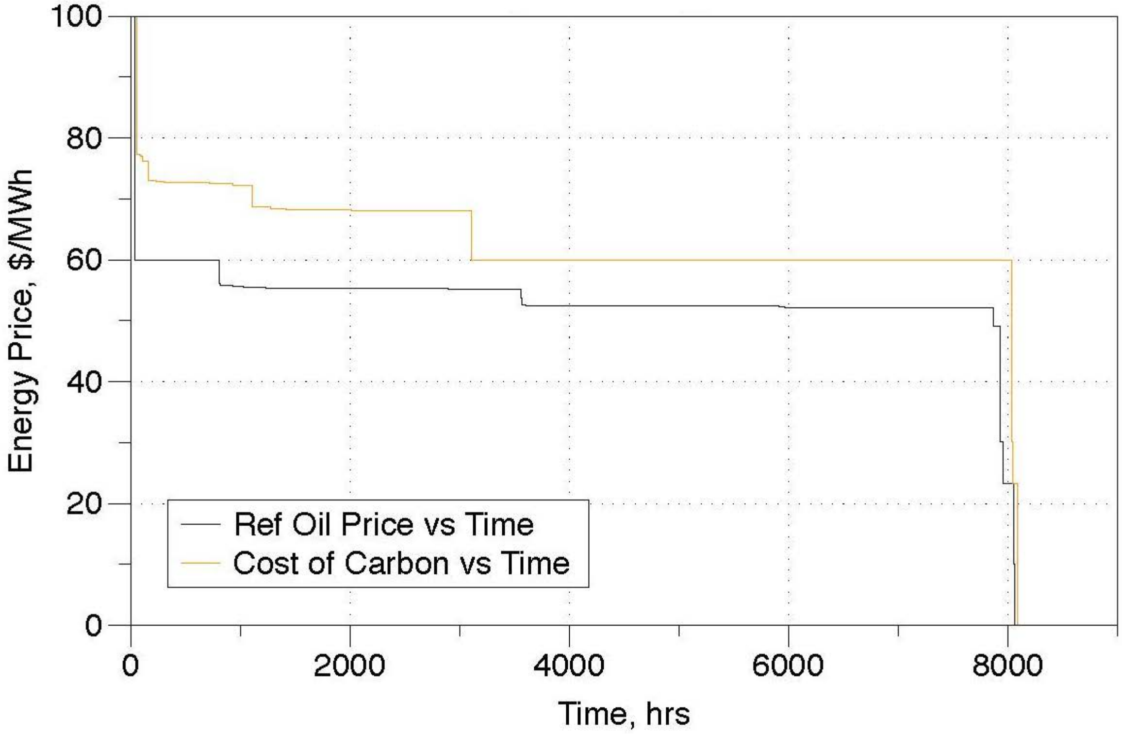

Figure 3. Cost duration curves for electricity energy prices with and without a $61/metric ton cost of carbon showing electrical energy prices over all hours of the year sorted from highest price to lowest

The price is $0/MWh for 704 hours in the year.

The second set of electricity prices is based on a grid with an electricity generation mix that has more volatile energy prices due to higher penetrations of PV. Within this report, we identify that price set as the volatile electricity price set. This price set was developed and discussed in Denholm et al. (2016).[49] All the scenarios in that report are located in California, but the electricity prices are sufficient to understand the impacts of increased price volatility on the N-R HES. In our analysis of the N-R HES, we use the reported scenario with 8.6% of the California electricity demand potentially served by California-located or California-owned wind power and 37% potentially served by California-located or California-owned solar (PV and concentrating solar power). Due to the high penetrations of wind and solar, some generation is expected to be curtailed resulting in California-located wind generation meeting 4.4% of the California load and California-located solar meeting 21% of the California load. Total curtailment is estimated at 12% of the California load. Other generators in California and the estimated percent of the load they meet are nuclear (5.7%); NGCCs (20%); gas combustion turbines (1.7%); combined heat and power (7.7%); biomass (3.4%); and geothermal (6.7%). Coal generation is less than 1% of the California load. In addition, the production cost model runs estimate that under the generation mix California imports 14% of it annual load. As with the standard electricity price set, the PLEXOS production cost model estimated the annual electrical energy production and hourly electrical energy prices. The analysis uses energy prices for the Pacific Gas & Electric Bay Area Balancing Authority. Ancillary service prices were not included with this price curve because they were not calculated in Denholm et al. (2016).[50] We expect the impact of ancillary service prices to be low because the base case income from ancillary services is 10% or less than the income from electrical energy in the base case conditions with the primary electricity energy price set (shown in Table 7 and Table 11). The marginal price of electricity is $0/MWh during 2,246 hr/yr. A price cap of $6,000/MWh was applied but is only reached during 4 hr/yr. The energy price is above $100/MWh during 213 hr/yr. Denholm et al. (2016)[51] did not develop an electricity price set that included a cost of carbon, so this analysis does not include that option. Figure 4 shows the resulting prices.

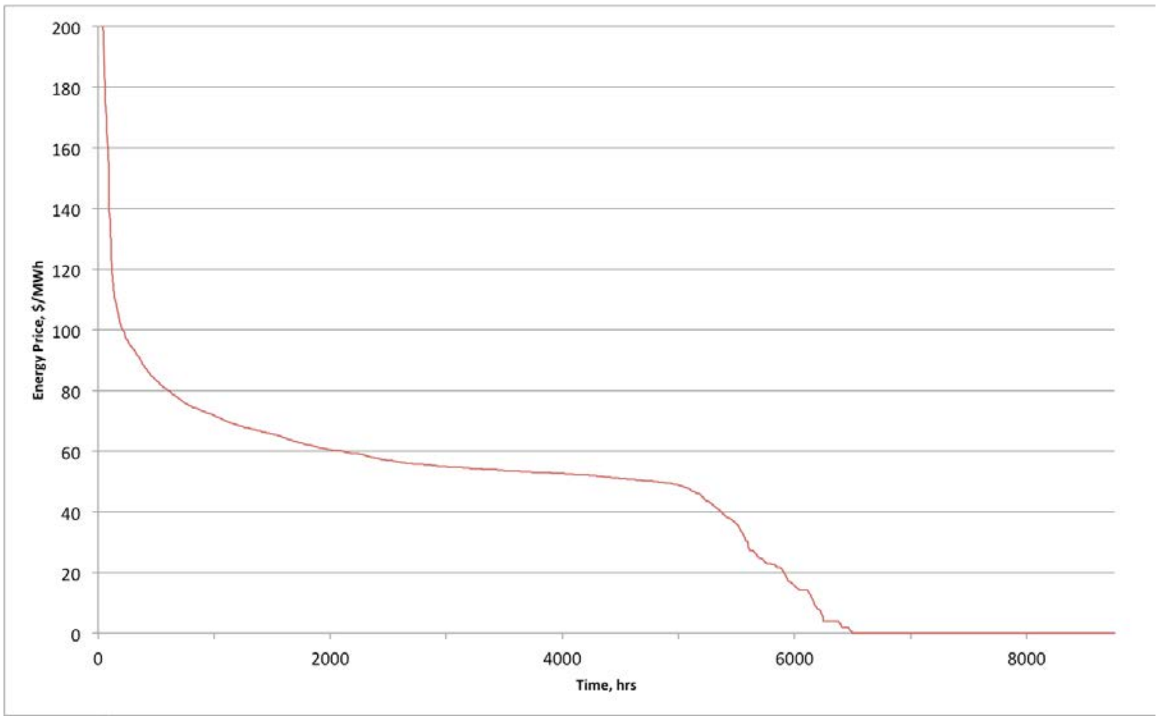

Figure 4. Cost duration curves for second set of electricity energy prices (more volatile energy prices) over all hours of the year sorted from highest price to lowest

The price is $0/MWh for 2,246 hours in the year.

Both sets of electricity prices are based on static mixes of electricity generators. The generation mix has varied historically due to new construction to replace retired units and units with high maintenance costs and/or low efficiencies and to meet increases in overall load and load profiles. The performance requirements for new units are defined based on projections of future changes, including changing prices for resources. Because our analysis results over the single year of the analysis do not include the impacts of decisions that are made for future years, they may undervalue opportunities in the evolving energy system.

For electricity that is purchased to produce hydrogen, we set the purchase price at the electrical energy price plus $15/MWh. The adder of $15/MWh is intended to cover costs that regional transmission organizations or independent system operators incur but are not paid for electrical energy (e.g., capacity, reserves, and administration). The adder is based on costs incurred by PJM Interconnection, as described in Ruth et al. (2016b).[52] The adder does not impact the value of electricity produced by either the nuclear reactor/thermal power cycle or the wind power plant within the N-R HES because that electricity is not purchased from the grid.

Using the financial parameters reported in Section 2.5, NGCC generators have a real levelized cost of electricity of $61.12/kWh if they operate at a 100% capacity factor. The real levelized cost of electricity increases to $62.24/kWh at a 92% capacity factor (the capacity factor if electricity is not generated during the 704 hr/yr when its value is $0/MWh).

2.3 Capacity Payment Estimates

As in the previous analyses, we included capacity payments to compensate generators necessary to meet a small number of "super-peak" demand hours each year. During these hours, the available capacity may be fully utilized and other reliability mechanisms, including use of operating reserves, are needed to maintain reliability and avoid rolling blackouts.

We estimated a base case capacity payment of $50/kW-yr based on observed variation of capacity payments in restructured markets over the last decade, as described in Ruth et al. (2016a).[53] In addition, we performed sensitivity analyses at two higher capacity payment levels: $100/kW-yr and $150/kW-yr. We required the N-R HES to provide electrical power to the grid for the 50 hours during the year with the highest load to receive a capacity payment (based on recent history of hours when available supply was limited as described in Ruth et al. [2016b]).[54] We allowed REopt to select configurations where the N-R HES does not provide full capacity during those hours, but the N-R HES only receives payment for the minimum quantity of power provided during all of those hours.

We restricted the N-R HES from simultaneously using grid electricity and generating electricity to receive a capacity payment. The N-R HES can use electricity generated by the nuclear reactor and the thermal power cycle during those hours to operate the electrolyzer, or the system can sell that power and receive the market price for energy and the capacity payment. In other words, we constrained the N-R HES from simultaneously selling the electricity to receive the capacity payment and purchasing electricity to operate the electrolyzer.

2.4 Capital and Operating Cost and Efficiency Estimates

We used the same capital and operating costs as in previous analyses when the equipment is consistent. Table 1 reports those capital and operating costs. Electricity generation costs are based on results in NREL's Annual Technology Baseline[55] and other NREL references, as listed in the tables. Electricity generation costs include equipment, engineering, construction, financing, and land—these can be considered the full costs of a new facility. Scaling is constant (i.e., economies of scale were not included). To be able to optimize the utilization of the thermal energy for HTE, we separated the nuclear reactor and thermal power cycle subsystems.

Table 1. Capital and Operating Costs for Subsystems in Previous Analyses

Unit	Capital Cost	Fixed O&M Cost	Reference
Nuclear Reactor	$3,716/kWe	$95/kWe-yr	Annual Technology Baseline*
Thermal Power Cycle	$1,305/kWe	-	
Wind Turbines	$1,689/kWe[56]	$46.75/kWe-yr[57]	See endnotes

kWe: kilowatt electric
O&M: operations and maintenance

Table 2 reports the capital and operating costs and efficiencies we used for both the high temperature electrolyzer and the low temperature electrolyzer in this analysis. Baseline costs and efficiencies for HTE and LTE are from the U.S. Department of Energy's (DOE's) H2A model production case studies.[58] In addition, we performed a sensitivity using lower capital costs and reduced efficiency LTE.

The HTE subsystem's capital and operating costs and its efficiency (electricity and thermal energy requirement) are based on the H2A case study titled "Future Central Hydrogen Production from Solid Oxide Electrolysis version 3.101.xlsm."[59] Costs in the H2A case study are reported in 2012 dollars. We did not convert them to 2014 dollars because we considered the uncertainty in the estimate to be much greater than the difference between the costs in the different years. The H2A case study reports a purchased cost for the HTE subsystem of $430/kWe. The H2A case study adds a 10% installation factor to the purchased cost to estimate an installed cost. The H2A case study also adds a 40% factor to the installed cost to include expenses for site preparation, engineering and design, project contingency, and up-front permitting. The resulting capital cost is $662/kWe. The H2A case study also reports fixed operating costs for labor, maintenance and repairs, and property tax and insurance. The annual labor cost estimate is $1,872,000/yr for a 50,000 kg H_2/day system. The maintenance and repair cost estimate is 3% of the total capital investment annually that, for a 50,000 kg H_2/day system, is $1,452,000/yr. The property tax and insurance cost estimate is 2% of the total capital investment annually that, for a 50,000 kg H_2/day system, is $968,000/yr. The total annual fixed operating cost estimate for a 50,000 kg H_2/day system is $4,292,000/yr. The H2A case study estimates the electricity and thermal energy requirement for the HTE subsystem to be 35.1 kilowatt-hours electric per kilogram of hydrogen (kWhe/kg H_2) and 11.5 kilowatt-hours thermal per kilogram of hydrogen (kWht/kg H_2,) respectively. At an electricity conversion efficiency of 35.1 kWhe/kg H_2, the fixed operating costs are $58.69/kWe-yr. The H2A performance and cost estimate is for a system operating at 800°C. We did not include a cost for heat upgrading nor did we include a cost for stack replacement; therefore, our results are likely to be somewhat optimistic.

LTE capital and operating costs and efficiency (electricity and thermal energy requirement) are based on the projections in the H2A case study titled "Future Central Hydrogen Production from PEM Electrolysis version 3.101.xlsm"[60] and are also reported in the DOE Hydrogen and Fuel

* The Annual Technology Baseline includes a $2/MWh electricity variable O&M cost for nuclear power generation. This study does not use that variable cost to be consistent with our previous N-R HES reports.

Cells Program Record on Hydrogen Production Cost from PEM Electrolysis.[61] Like the HTE scenario, costs in the H2A case study are reported in 2012 dollars, and we did not convert them to 2014 dollars. The H2A case study reports a purchased cost for the LTE subsystem of $400/kWe. The H2A case study adds a 10% installation factor to the purchased cost to estimate an installed cost. The H2A case study also adds a 40% factor to the installed cost to include expenses for site preparation, engineering and design, project contingency, and up-front permitting. The resulting capital cost is $616/kWe. The H2A case study reports fixed operating costs for labor, maintenance and repairs, and property tax and insurance. The annual labor cost estimate is $1,248,000/yr for a 50,000 kg H_2/day system. The maintenance and repair cost estimate is 3% of the total capital investment annually that, for a 50,000 kg H_2/day system, is $1,933,000/yr. The property tax and insurance cost estimate is 2% of the total capital investment annually that, for a 50,000 kg H_2/day system, is $1,288,000/yr. The total annual fixed operating cost estimate for a 50,000 kg H_2/day system is $4,469,000/yr. The H2A case study estimates the electricity requirement for the LTE subsystem to be 50.2 kWhe/kg H_2, which results in a 66% efficient electrolyzer (lower heating value basis). At an electricity conversion efficiency of 50.2 kWhe/kg H_2, the fixed operating costs are
$42.73/kWe-yr.

The DOE Fuel Cell Technologies Office set more aggressive targets for low temperature PEM electrolysis in their Multi-Year Research, Development, and Demonstration Plan.[62] In that plan, the electrolyzer cost target is $242/kW (in 2007$) and the electricity requirement for the LTE subsystem target is 44.7 kWhe/kg H_2, which results in a 75% efficient electrolyzer (lower heating value basis). These values are provided as research targets, whereas the H2A values are projections. To be consistent with our other N-R HES analyses, we chose to use projected values instead of the targets.

The H2@Scale Big Idea team has proposed that LTE could potentially have lower capital costs if the efficiency requirement is relaxed. The team developed a concept where electricity that would otherwise be curtailed is used to produce hydrogen, and that hydrogen is used for transportation and industrial sectors and to supplement natural gas. Specifically, the H2@Scale Big Idea team proposes a potential future LTE with a $100/kWe purchase cost and 60% efficiency (lower heating value basis).[63] Using the same installation factor and additional expenses as we used for the reference LTE case above, the capital cost for a low capital cost LTE subsystem is $154/kWe. A 60% efficient LTE subsystem requires 55.2 kWhe/kg H_2. We kept the fixed O&M costs the same as the base LTE subsystem.

Table 2. Capital and Operating Costs and Efficiencies for Electrolyzers

Unit	Capital Cost	Fixed O&M Costs	Electricity Requirement	Thermal Energy Requirement
High Temperature Electrolysis (HTE) Subsystem	\$662/kWe	\$58.69/kWe-yr	35.1 kWhe/kg H_2	11.15 kWht/kg H_2
Low Temperature Electrolysis (LTE) Subsystem with Projected Capital Cost	\$616/kWe	\$42.73/kWe-yr	50.2 kWhe/kg H_2	N/A
Low Temperature Electrolysis (LTE) Subsystem with Low Capital Cost	\$154/kWe	\$42.73/kWe-yr	55.2 kWhe/kg H_2	N/A

2.5 Financial Parameters and Calculations

We performed an analysis of the annual cash flows for the 25-year project financial life for each N-R HES using the financial recommended by Short (1996)[64] and used in the previous N-R HES analyses performed by JISEA.[65] Those parameters are shown in Table 3. These financial parameters result in a weighted average cost of capital of 10% which can be met at various debt/equity ratios with different discount rates. We recognize that the debt-to-equity ratio, cost of equity, and other parameters are dependent upon the industry, risk profile, and other factors. The parameters used in this analysis are intended to be an example but may not match the financial parameters that investors might have. Case-specific analysis on the financial viability of these systems is warranted as specific locations and circumstances are identified.

Table 3. Key Financial Parameters

Start of operations (year)	2035
Analysis period (years)	25
Tax rate	35%
Cost of equity	10%
Debt percentage	0.00%
Discount rate (nominal)	10%
Inflation rate (electricity/water/gasoline/natural gas)	3.0%

Oxygen could potentially be sold as a byproduct of the electrolysis process, but the size and potential customer location are unknown. Therefore, we did not include a byproduct credit for oxygen generation. The reader could estimate a byproduct credit and add it to the hydrogen price when interpreting the result figures. If oxygen's value minus its delivery cost is between \$0.03/kg O_2 and \$0.05/kg O_2, the impact on the hydrogen price is \$0.24/kg H_2 to \$0.40/kg H_2. If the reader believes the appropriate hydrogen price is \$1.47/kg, then the effective hydrogen plus oxygen price is \$1.71–\$1.87/kg H_2.

2.6 Cost of Carbon

To add a cost of carbon emissions to specific scenarios, we used the range of social costs of carbon. The U.S. government provides social costs of carbon for use in analyses of the climate benefits of policies and rules as developed by the Interagency Working Group.[66] Social costs of carbon estimate the economic damages associated with small increases in CO_2 emissions. Because the damage estimates are future-looking, the government uses three different discount rates to convert the values to current year dollars: 5%, 3%, and 2.5%. In addition, because the extent of damages is uncertain, the government provides a second value with a 3% discount rate that uses the 95th percentile of the range of damage estimates instead of the mean.[67] Table 4 reports the estimated social cost of carbon in 2035 in 2014 dollars. These values were used because we considered the difference between 2013 dollars and 2014 dollars negligible.

Table 4. Social Costs of Carbon Emissions in 2035 (2014 \$/metric ton CO_2e)

Discount Rate and Statistic	5%	3%	2.5%	3% 95th percentile
2035 Cost	$20	$61	$86	$186

2.7 Cost of Hydrogen Produced Via Steam Methane Reforming

For comparative purposes, we estimated the cost of producing hydrogen from natural gas using the steam methane reforming process. We used natural gas prices from the 2015 Annual Energy Outlook's Reference Case[68] to be consistent with our previous analysis of two N-R HESs.[69] We used DOE estimates of potential future capital and fixed operating costs from the H2A case study titled "Future Central Hydrogen Production from Natural Gas without CO_2 Sequestration version 3.101.xlsm."[70] When the reference year is adjusted to 2012, the H2A model shows an estimated total capital investment of $162,944,000, fixed O&M costs of $6,427,000/yr, and variable operating costs (for electricity, demineralized water, and cooling water) of $5,234,000/yr. The H2A model also shows that the natural gas requirement is 156,000 British thermal units per kilogram of hydrogen (calculated based on the lower heating value of natural gas not its higher heating value). Using those values, the AEO projected natural gas price of $6.98/mmBtu, and the financial parameters listed in Section 2.5, the minimum hydrogen selling price is $1.47/kg H_2 without a cost of carbon.

Note that hydrogen produced by steam methane reforming likely has a lower maximum pressure than that produced via electrolysis. If higher-pressure hydrogen is required, the compression cost difference should be added to the minimum selling price of hydrogen produced via steam methane reforming.

We estimated carbon dioxide emissions from the steam methane reforming process to be 10.4 kg CO_2/kg H_2 based on emissions reported in the 2009 Hydrogen Pathways Report.[71] Note that the emission estimate includes emissions from natural gas combustion that provides the process heat to drive the reforming reaction. Those emissions are higher than the stoichiometric emissions of 5.45 kg CO_2/kg H_2 that is realized when one mole of methane plus two moles of water generates four moles of hydrogen and one mole of carbon dioxide. Heat integration may reduce the overall emissions to a point closer to the stoichiometric level.

Using that emission factor and the social costs of carbon reported in Table 4, we estimated the minimum hydrogen selling price for hydrogen produced from natural gas at each social cost of carbon. Table 5 reports the resulting minimum hydrogen selling prices. This analysis focuses on the 3% discount rate for the social cost of carbon ($61/metric ton CO_2e). At that cost, the minimum hydrogen selling price to meet the required financial parameters is $2.20/kg.

Table 5. Impacts of Social Cost of Carbon on Required Hydrogen Prices for Hydrogen Produced from Natural Gas

Social Cost of Carbon Discount Rate and Statistic	5%	3%	2.5%	3% 95th Percentile	No Social Cost of Carbon
Minimum hydrogen selling price ($/kg) for hydrogen produced from natural gas	$1.73	$2.20	$2.49	$3.72	$1.47

The steam methane reforming process emits other pollutants in addition to carbon dioxide. Those pollutants include non-methane hydrocarbons, nitrogen oxides, sulfur oxides, carbon monoxide, particulates, and benzene.[72] In this analysis, we did not consider additional costs to mitigate those pollutants or payments within a cap-and-trade program. If those costs are included, they will increase the minimum selling price for hydrogen produced using that technology.

The price of natural gas is uncertain and may differ from the $6.98/mmBtu used in this analysis based on the 2015 AEO projection for 2035.[73] That price differs from more recent estimates such as the 2017 AEO's Reference Case projection of the 2035 price for natural gas, which is $5.94/mmBtu.[74] If the natural gas price is different, the price of hydrogen produced from it will differ as well. Figure 5 shows the impact of natural gas prices on minimum hydrogen selling prices with and without a $61/metric ton CO_2e cost of carbon.

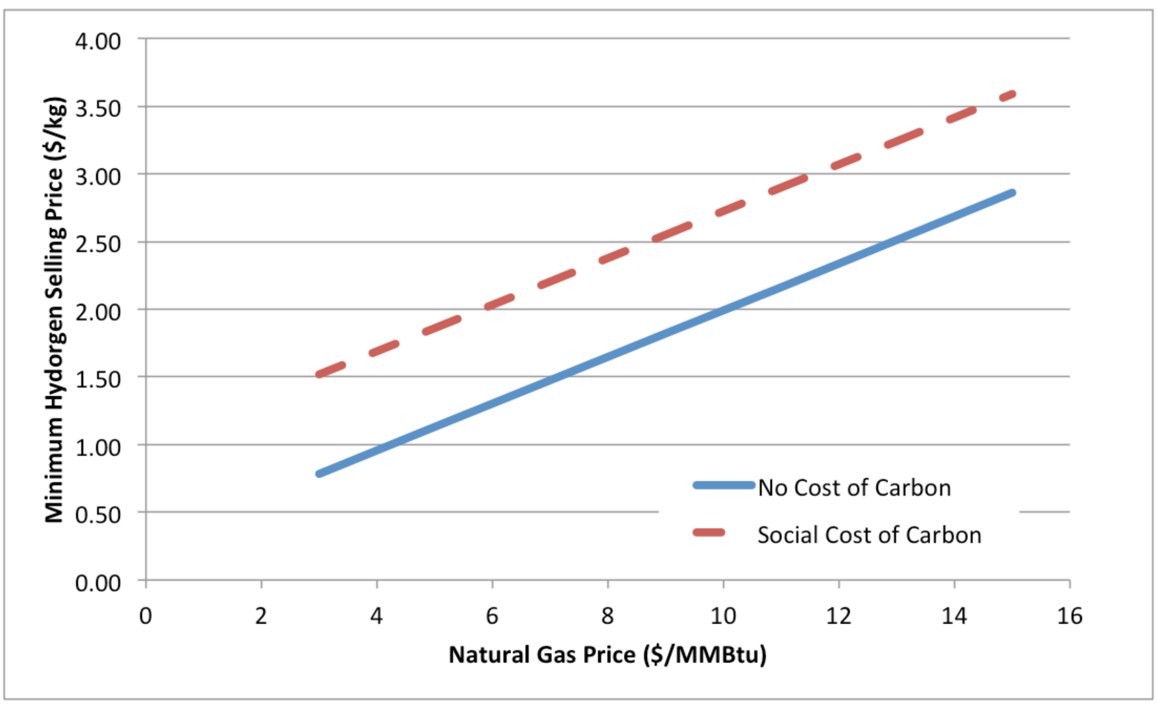

Figure 5. Impacts of natural gas prices on minimum hydrogen selling prices

As a comparison, Table 6 shows the minimum selling price for hydrogen produced via both HTE and LTE. The minimum hydrogen selling prices are calculated using the efficiencies and capital and operating costs reported in Section 2.4, financial parameters discussed in Section 2.5, and the average of electricity purchase price with and without a \$61/ton CO_2e cost of carbon—the Interagency Working Group's social cost of carbon at a 3% discount rate. Those averages were calculated as the mean of the hourly electricity energy purchase prices reported in Section 2.2 and shown in Figure 3. They are \$64.50/MWh without a cost of carbon and \$73.90/MWh with the cost of carbon. The price of heat for this calculation is \$7.57/mmBtu based on a natural gas price of \$6.98/mmBtu with an efficiency of 94% and heat price of \$17.66/mmBtu with a cost of carbon. Note that oxygen is a co-product from electrolysis and could be sold if customers are available, but we did not assign any value to oxygen.

Table 6. Estimated Minimum Selling Prices for Hydrogen Produced Via Electrolysis

Minimum Selling Prices for Hydrogen Produced Via Electrolysis	No Cost of Carbon	\$61/ton CO_2e Cost of Carbon
Low Temperature Electrolysis (\$/kg)	\$3.87	\$4.34
High Temperature Electrolysis (\$/kg)	\$3.09	\$3.81

3 N-R HES Design on Operational Optimization Results

3.1 Results for the High Temperature Electrolysis Scenario

The HTE scenario involves four primary subsystems: (1) a nuclear reactor, (2) a thermal power cycle that can be associated with the nuclear reactor, (3) a wind power plant, and (4) an HTE subsystem that uses electricity and thermal energy to produce hydrogen. We set the same maximum size for the nuclear reactor, the thermal power cycle, the wind power plant, and the THE subsystem—50 MWe—to show the impacts of each subsystem clearly. The thermal power cycle efficiency of 30% implies a thermal capacity of 167 MWt for the nuclear reactor. A 50 MWe HTE subsystem running at full capacity would use both 50 MWe electricity and 16.4 MWt heat; thus, it has the potential to use electricity and heat from the wind power plant and nuclear reactor.

We used REopt to identify the optimal size of each subsystem and the optimal energy dispatch on an hourly basis. The model allows for energy to be split (i.e., some of the thermal energy from the nuclear reactor can be used as heat in HTE and the remainder can produce electricity) during any hour as long as that solution is optimal for the N-R HES.

3.1.1 Potential Profitability

We analyzed the potential profitability of HTE N-R HES by varying the prices of the electricity and hydrogen products and using REopt to calculate the optimal set of subsystems and internal dispatch, as discussed in Section 2.1. We varied the hydrogen price from \$0/kg to \$10/kg to identify how various prices might impact the results. As in previous analyses, we also varied the price of electricity using a multiplier that affected the electricity energy price for all 8,760 hours in the year.[*] For each run, the multiplier was randomly assigned a value between 0 and 2 so the electrical energy price in that run could be \$0/MWh for every hour of the year, twice the electrical energy price developed for the reference case for every hour, or any other multiplied value between 0 and 2. The electricity price multiplier could be considered a proxy for (1) the difference between marginal generation costs and market prices (due to bidding strategies and market settlement), and (2) uncertainty in the natural gas price because natural gas is on the operating cost margin for the vast majority of the year.[75] All other parameters were kept at the reference values unless noted otherwise (i.e., for a sensitivity). Note that the analysis methodology we used presumes perfect foresight of all expenses, the renewable resource, and product prices throughout the project financial life.

Figure 6 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers at a capacity payment of \$50/kW-yr. Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. The results of this analysis show:

[*] Prices of ancillary services (reserves, flex reserves, and regulation up and down) were not multiplied because a change in price has little effect on the operational selection and optimization.

- If the electricity price multiplier is below 1.22 and the hydrogen price is below approximately $1.25/kg depending upon the price of electricity, none of the configurations are profitable (i.e., the NPV is less than zero for all configurations under those conditions), as shown by the area in Figure 6 with no dots. Note that the minimum hydrogen price where a profitable configuration is possible depends on the price of electricity. This is because electricity can be purchased to produce hydrogen, and that option becomes increasingly profitable as the price of electricity goes down.
- If the electricity price multiplier is between 1.25 and 1.3 and the hydrogen price is below $3.00/kg (as shown by the dark blue dots), the only profitable configuration is the wind power plant without any other subsystems. Neither the price of electricity, including a possible capacity payment, nor the price of hydrogen is sufficient to overcome the capital and operating costs of the nuclear reactor with a thermal power cycle or those with HTE.
- If the electricity price multiplier is above 1.3, the hydrogen price is below $4.00/kg, and the prices of hydrogen and electricity are in the range indicated by the orange dots, the nuclear reactor with a thermal power cycle has sufficient income from selling electricity and receiving a capacity payment to be profitable. In addition, the wind power plant is profitable, so the configuration includes the nuclear reactor, the thermal power cycle, and the wind power plant. Hydrogen production does not increase the NPV, so this configuration of the N-R HES does not include HTE and does not produce any hydrogen.
- If the electricity price multiplier is below 0.95 and the hydrogen price is above $2.00/kg and in the range shown by the yellow dots, the optimal configuration includes the nuclear reactor and HTE. The nuclear reactor only provides heat to HTE. The grid would provide electricity.
- If the electricity price multiplier is between 0.95 and 1.05 and the hydrogen price is above $3.00/kg (as shown by the light blue dots), the optimal configuration includes the nuclear reactor, HTE subsystem, and the wind power plant. The HTE subsystem uses electricity generated by the wind power plant supplemented by grid electricity when the wind is not blowing. Because this configuration does not include a thermal power cycle, the nuclear reactor provides heat only for hydrogen production.
- If the electricity price multiplier is above 1.05 and the hydrogen price is above $4.00/kg and in the range indicated by the pink dots, the optimal configuration includes the nuclear reactor, the thermal power cycle, the HTE subsystem, and the wind power plant. This is the full configuration for this scenario. The heat generated by the nuclear reactor is used primarily for HTE, and electricity for HTE comes from the wind power plant and the grid, except during the hours necessary to receive the capacity payment.
- If the electricity price multiplier is below 0.45 and the price of hydrogen is between $1.25/kg and $2.00/kg (the purple dots in the figure), the optimal configuration includes the nuclear reactor, the thermal power cycle, and HTE. The nuclear reactor generates thermal energy for electricity generation to receive the capacity payment and for HTE during the other hours during the year.

Note that configurations indicated by the yellow, light blue, and pink dots include LTE subsystems and produce electricity. The left side of those configurations forms a diagonal line—the hydrogen price-electricity price multiplier combinations to the right of that line include LTE subsystems and produce hydrogen; configurations to the left of that line do not include LTE subsystems and do not produce hydrogen.

The hydrogen cost and the electricity cost multiplier are randomly sampled from the uniform distribution to generate the inputs for the sensitivity analyses. In this case, a banding pattern occurs in the sampled space because we took the same number of samples for each variable but from different absolute ranges (for the electricity cost multiplier and hydrogen cost). We did not focus on correcting the banded nature of the samples because the randomization of the variables is a convenient way to sample the sensitivity space.

The solid black dot in Figure 6 indicates the reference case electricity price vector (i.e., the electricity price multiplier is 1.0) and hydrogen price ($1.47/kg). To estimate the reference case hydrogen price, we estimated the cost of producing hydrogen via steam methane reforming of natural gas, as described in Section 2.7. Variations in natural gas prices will move the location of that dot and the movement can be estimated using Figure 5.

The separation between the configurations with pink and orange dots depends on both the hydrogen and electricity prices because, as the electricity price multiplier is held constant and the hydrogen price increases (horizontal on Figure 6), hydrogen becomes more valuable than electricity. In that case, use of thermal energy for HTE displaces use of the thermal energy to make electricity. Likewise, as the hydrogen price is held constant and the electricity price increases, electricity becomes more valuable than hydrogen and the N-R HES's optimal configuration produces electricity instead of hydrogen.

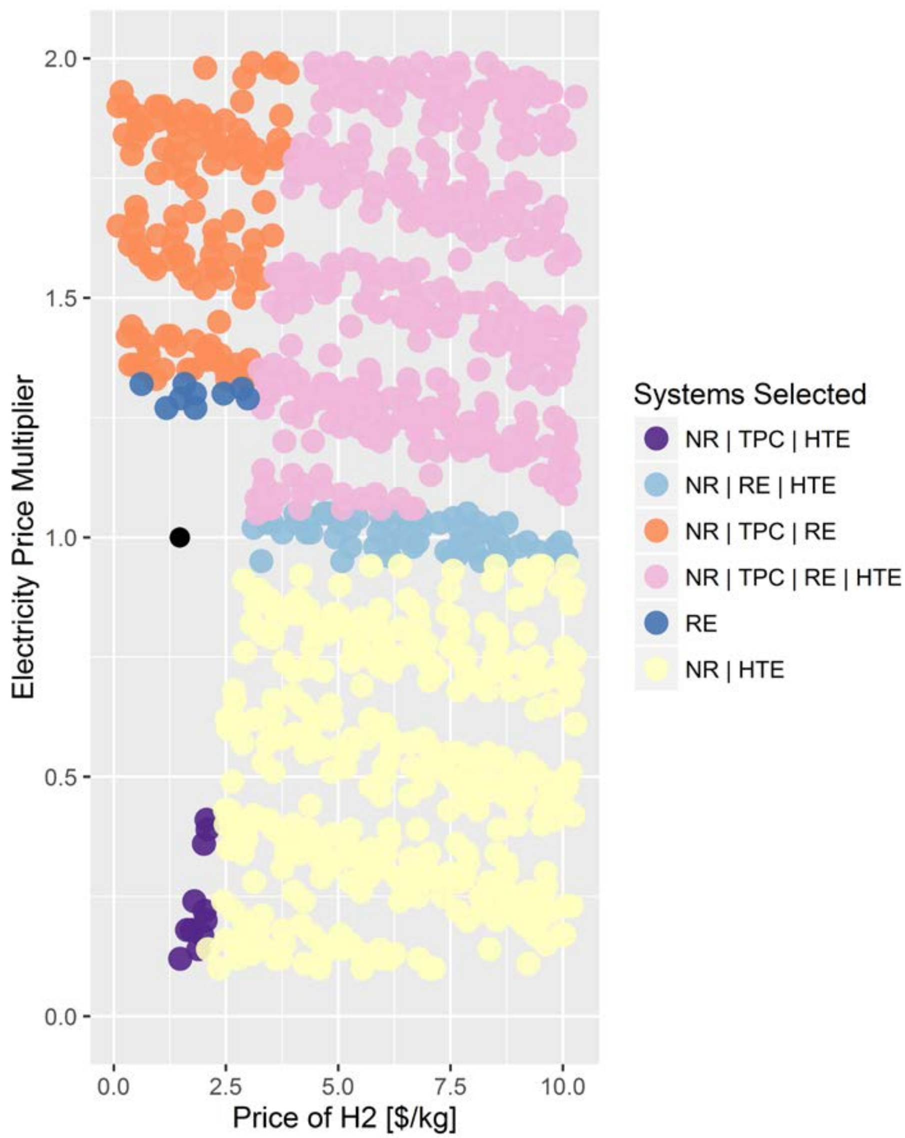

Figure 6. Optimal configurations for the HTE scenario with a capacity payment of $50/kW-yr

HTE: high temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 7 and Figure 8 expand upon the information in Figure 6. Figure 7 shows the optimal amount of electricity purchased from the grid at various electricity price multipliers and hydrogen prices. In all conditions with configurations that include HTE, at least some electricity is purchased. This is because the nuclear reactor is constrained to a maximum capacity of 50 MWe, so its maximum size is too small to produce both sufficient heat and electricity for HTE if HTE is at its maximum capacity. The wind power plant can supplement electricity generation so that, during some hours when the wind is blowing, no electricity needs to be purchased. The value of hydrogen production is sufficient so that, during the hours when the wind is not blowing, purchasing electricity to produce hydrogen is the economic option.

Note that in profitable configurations where the electricity price multiplier is below 0.95, the maximum amount of electricity is purchased. Those configurations are primarily the yellow dots in Figure 6—the configurations only include the nuclear reactor and HTE. With electricity price multipliers below 0.95, the nuclear reactor only produces heat for HTE and the required electricity is purchased. The optimal capacity of HTE in that range is its maximum (as shown in the third graph from the left in Figure 8). Because the HTE subsystem's maximum capacity is 50 MWe, its maximum heat requirement is 16.4 MWt. The nuclear reactor could meet that thermal energy requirement at approximately 10% of its maximum capacity of 167 MWt (which can produce 50 MWe at 30% efficiency). That lower capacity is optimal, as shown by the lighter dots in the leftmost graph in Figure 8.

Profitable configurations where the electricity price multiplier is between 0.95 and 1.1 involve less purchased electricity than those where the electricity price multiplier is lower than 0.95 (the color's shade is not as dark in Figure 7). At an electricity price multiplier greater than 0.95, the wind power plant could provide electricity at an average cost lower than purchased electricity; hence, the optimal configuration includes the wind power plant (light blue and pink dots in Figure 6). The electricity produced by the wind power plant displaces electricity purchased from the grid at lower electricity price multipliers. At an electricity price multiplier greater than 1.1, the combined nuclear reactor and thermal power cycle could also produce electricity at a lower cost than purchased electricity; hence, the optimal configuration includes a thermal power cycle (pink dots in Figure 6). The combination of the two decreases the electricity purchase requirement. Electricity is still purchased in that price range because the HTE subsystem has a capacity greater than can be met by the nuclear reactor and the thermal power cycle when some of the nuclear-generated heat provides thermal energy to the HTE subsystem.

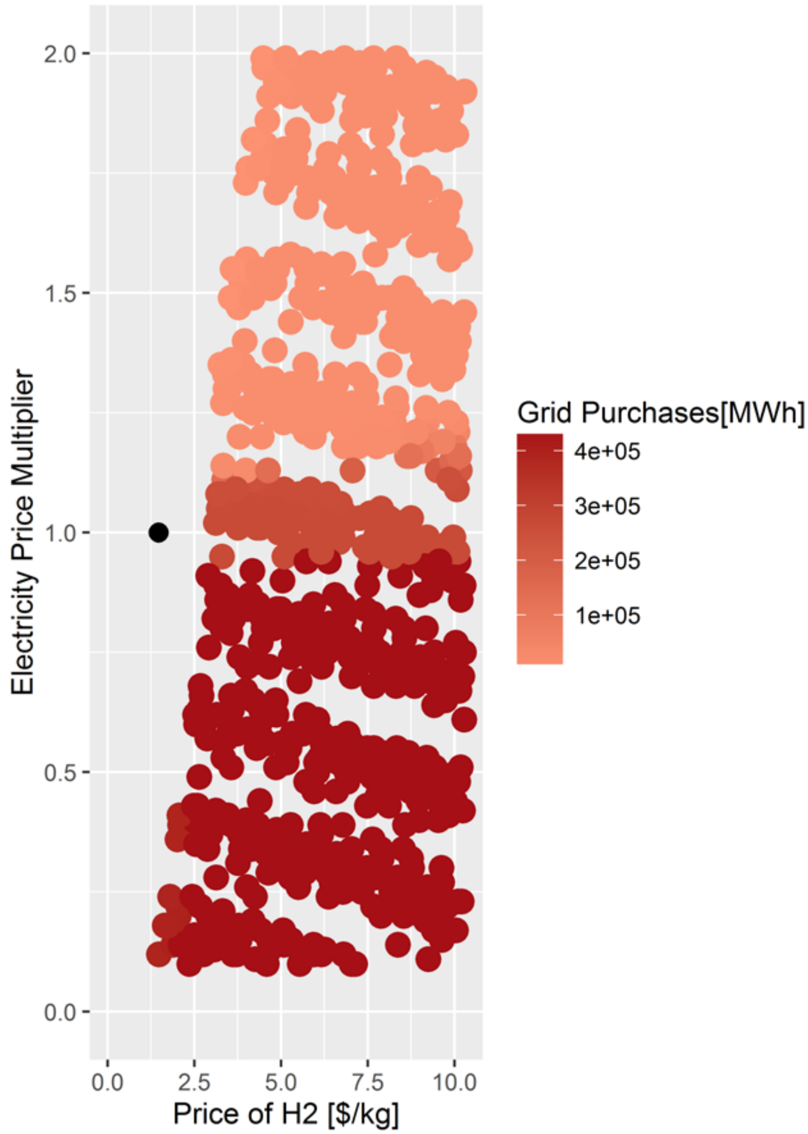

Figure 7. Optimal electricity purchases for the HTE scenario with a capacity payment of $50/kW-yr

As shown in the third graph from the left in Figure 8, the optimal capacity of the HTE subsystem (when included in the optimal configuration) is usually its maximum size (50 MWe). The exceptions (shown in a lighter shade) are some points where the electricity price multiplier is above 1.25 and the hydrogen price is at the low end of the profile. In those cases, the tradeoff between value for electricity generation and hydrogen generation is small; that tradeoff introduces variations in the configuration design.

The rightmost graph in Figure 8 shows that the optimal capacity of the wind power plant is not always its maximum capacity. At electricity price multipliers in the range of 1.15–1.22, the wind power plant is below its maximum capacity because the price of electricity is in a narrow window. The electricity price is low enough to purchase some electricity during many of the hours when the wind is blowing—instead of paying for the capital and operating expenses of a wind power plant at the maximum capacity. However, the electricity price is high enough that the optimal N-R HES receives income from electricity generation during other hours of the year.

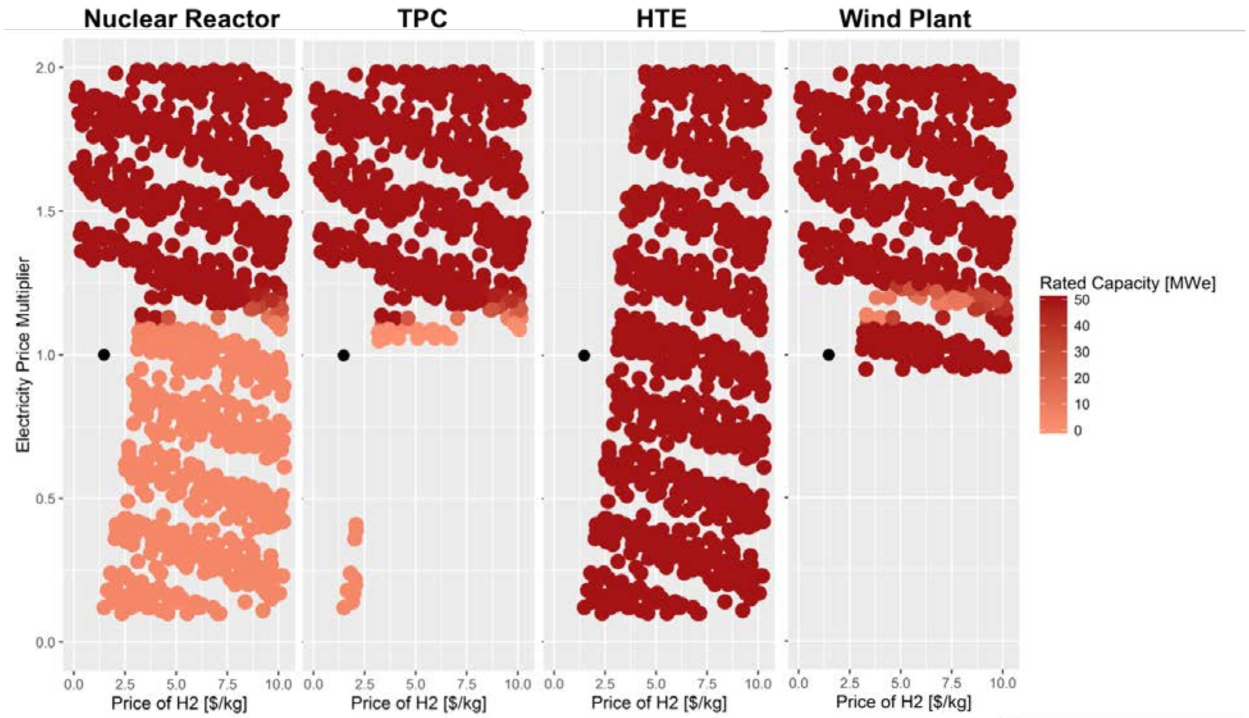

Figure 8. Optimal capacities of each subsystem for the HTE scenario with a capacity payment of $50/kW-yr

TPC: thermal power cycle
HTE: high temperature electrolysis subsystem
Solid black dots at $1.47/kg and 1.0 indicate reference case hydrogen and electricity prices.

Figure 9 shows the optimal product mix based on each optimal configuration reported in Figure 6. The graph on the right in Figure 9 shows that hydrogen production is maximized in most profitable combinations of hydrogen prices and electricity price multipliers. One exception is the ranges where the thermal power cycle is included with the nuclear reactor and HTE at low electricity price multipliers (the purple dots in Figure 6). In that range, capacity payments provide more value than hydrogen sales. The other exception is the range where the electricity price multiplier is above 1.25 and the hydrogen price is at the low end of being included in the most profitable configuration. The third graph from the left in Figure 8 shows that the HTE subsystem is not optimally sized at its maximum capacity in that range because the tradeoff between value for electricity generation and hydrogen generation is small; that tradeoff introduces variations in the configuration design.

The black dots in the left graph in Figure 9 indicate the range of electricity price multipliers and hydrogen prices where hydrogen is not produced. In that range, electricity generation is maximized from both the wind power plant and the nuclear reactor/thermal power cycle. Immediately below that set of dots (i.e., where the electricity price multiplier is between 1.25 and 1.3 and the hydrogen price is below $3.00/kg—also shown by the dark blue dots in Figure 6), the electricity price is only sufficient for the wind power plant to be profitable. Therefore, annual electricity generation is much lower because the optimal configuration does not include the nuclear reactor or the thermal power cycle.

The darker orange dots in the left graph in Figure 9 indicate the range where electricity sales are optimally reduced because some of the electricity is used in the HTE subsystem to produce hydrogen. Electricity sales are further reduced in the lighter orange dots because the nuclear reactor is smaller and primarily provides thermal energy for HTE (i.e., the nuclear reactor's primary role is not to provide thermal energy to the thermal power cycle for electricity generation).

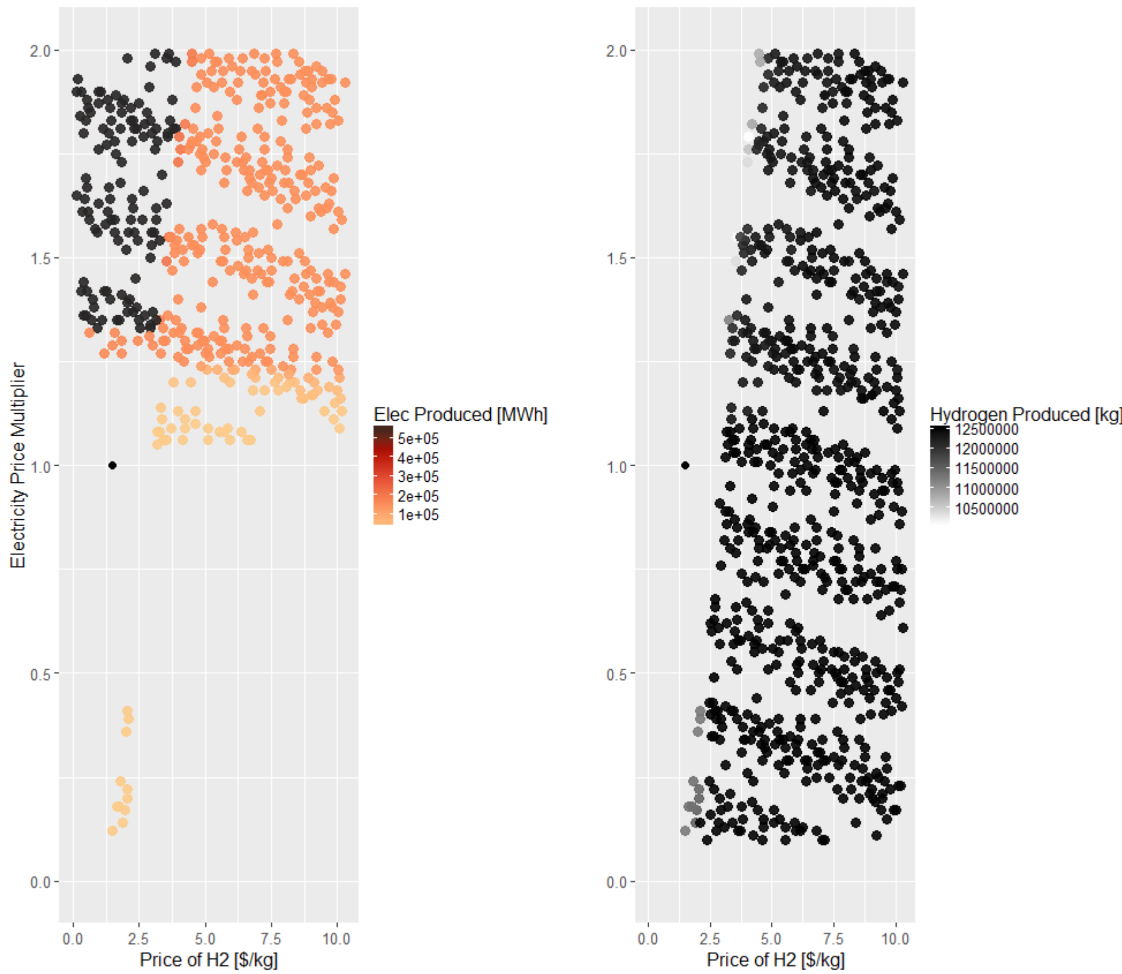

Figure 9. Optimal annual product generation for the HTE scenario at various hydrogen prices and electricity price multipliers

Electricity is on the left; darker colors indicate greater generation. Hydrogen is on the right. Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Solid black dots at $1.47/kg and 1.0 indicate reference case hydrogen and electricity prices.

Figure 10 shows the optimal expected capacity payment. The optimal HTE scenario receives a capacity payment whenever the thermal power cycle is included (see the second graph from the left in Figure 8) because receiving a capacity payment is always the optimal operational strategy in configurations that include a thermal power cycle. When the thermal power cycle is included in the optimal configuration at electricity price multipliers below 1.15, it is smaller and thus receives a smaller capacity payment. The reason is that the income from electricity and hydrogen are almost identical in that range. Most of the energy produced by the nuclear reactor is used to produce hydrogen but a small amount of electricity is generated during the hours of maximum electricity energy prices and available capacity payment. The optimal fraction to produce electricity is not obvious due to variability in the price of electricity (both selling and buying) and the variability of wind production.

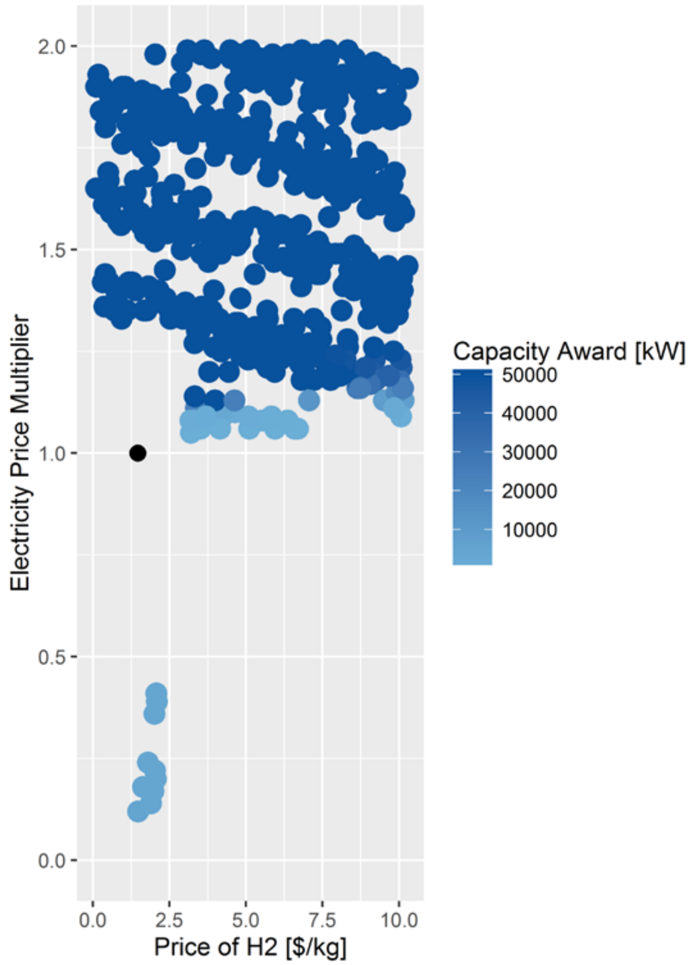

Figure 10. Optimal capacity payments awarded for the HTE scenario at various hydrogen prices and electricity price multipliers

Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 11 shows the NPVs for the optimal configurations shown in Figure 6. Note that profitability increases more dramatically with increasing hydrogen prices than with increasing electricity prices.

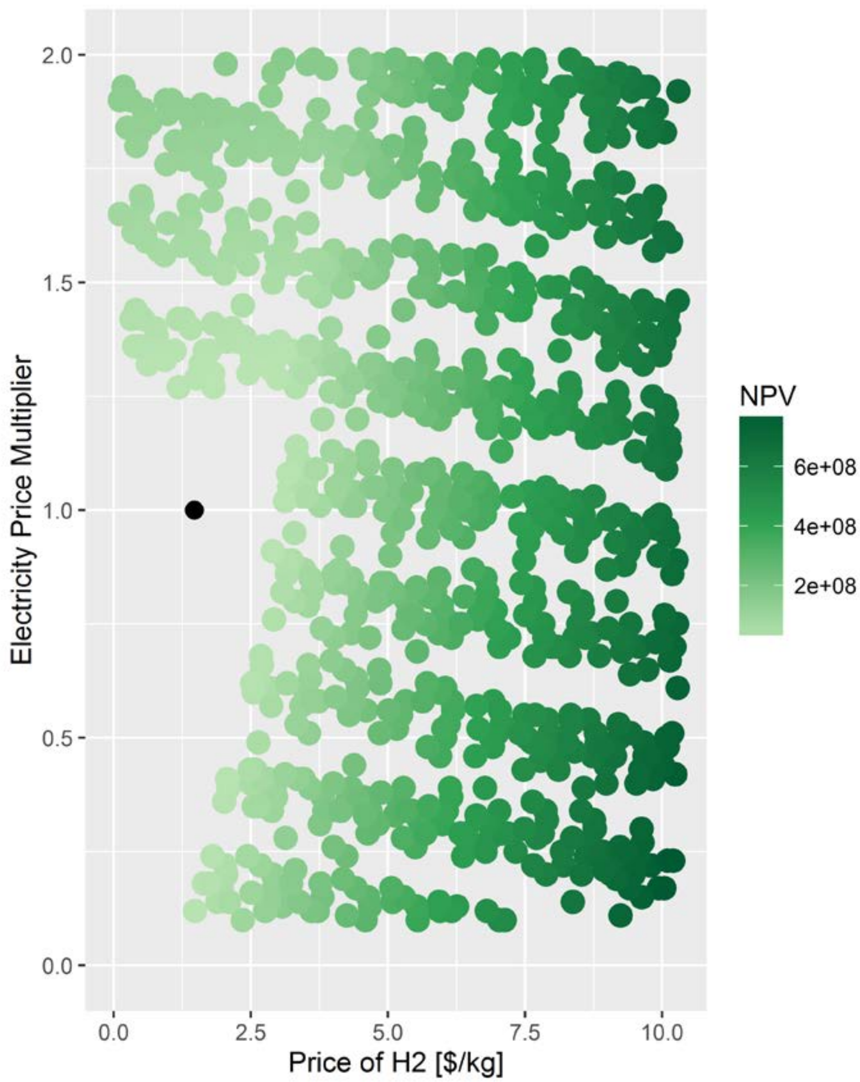

Figure 11. Optimal NPVs awarded for the HTE scenario at various hydrogen prices and electricity price multipliers

Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Darker shades indicate higher NPVs.

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Table 7 provides the present values of all the annual revenues and expenses for optimal operations of configurations under the base case parameters. Note that none of these configurations is identified as profitable (i.e., the NPV for all of them is less than $0). The first of those configurations includes only a nuclear reactor and a thermal power cycle. In the second configuration, a wind power plant is added. The third configuration includes the nuclear reactor, thermal power cycle, and HTE. In that configuration, the HTE subsystem could use heat from the nuclear reactor to generate hydrogen during most of the hours each year if the price of hydrogen is high enough. The final configuration includes both the wind power plant and HTE. That configuration also optimizes the product dispatch to maximize profit and generates hydrogen if its price is high enough. In the last two configurations, over the course of the year, the N-R HES could both purchase and sell electricity because sales and purchases could be at different times.

Table 7. High Temperature Electrolysis Scenario Present Values at Base Case Conditions for Four Configurations

Configuration	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + High Temperature Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe) + High Temperature Electrolyzer (50 MWe)
	Present Value ($million)	Present Value ($million)	Present Value ($million)	Present Value ($million)
Nuclear Plant				
Reactor Capex	-$186	-$186	-$186	-$186
Nuclear Fixed O&M	-$55	-$55	-$55	-$55
Thermal Power Cycle				
Thermal Power Cycle Capex	-$65	-$65	-$65	-$65
Wind Power Plant				
Capex	$0	-$85	$0	-$85
Fixed O&M	$0	-$27	$0	-$27
High Temperature Electrolyzer				
Capex	$0	$0	-$33	-$33
Fixed O&M	$0	$0	-$34	-$34
Revenue				
Purchased Electricity	$0	$0	$0	$0
Hydrogen Revenue	$0	$0	$0	$0
Capacity Payments	$29	$29	$29	$29
Electricity Revenue	$250	$345	$250	$345
Ancillary Services	$0	$0	$25	$25
Taxes	-$33	-$34	-$24	-$25
NPV	-$60	-$77	-$93	-$111

Capex: capital expenditure
Negative values indicate expenses and positive values indicate income.

Table 8 compares other financial parameters of the nuclear-only configuration and the alternatives identified in Table 7. At -$60 million, the NPV for the nuclear reactor/thermal power cycle configuration is less negative than the options with additional subsystems. Adding the wind power plant reduces the NPV to -$77 million due to increased capital that is not offset by the value of electricity generated. Likewise, adding HTE to the initial configuration reduces the NPV to -$93 million because there are capital and fixed operating costs for the HTE subsystem but no hydrogen is produced, so there is no additional revenue. The full configuration's NPV is more negative at -$111 million. Even though the third and final configurations include HTE subsystems, they do not produce hydrogen even during hours when the electricity price is $0/MWh because they optimally bid into the regulation down market during those hours.

Table 8. High Temperature Electrolysis Scenario Output Summary at Base Case Conditions for Four Configurations

Configuration	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + High Temp. Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe) + High Temp. Electrolyzer (50 MWe)
Annual Electricity Output to Grid (GWh)	438	574	438	574
Annual Electricity Purchases (GWh)	N/A	N/A	0	0
Annual Hydrogen Production (metric ton)	N/A	N/A	0	0
TCI ($million)	$251	$336	$284	$369
NPV at 10% Discount Rate ($million)	-$60	-$77	-$93	-$111
Payback Period (years)	N/A	N/A	N/A	N/A
IRR after 25 years of operation	6.4%	6.5%	4.9%	5.3%
NPV/TCI Ratio	-0.24	-0.23	-0.33	-0.30

TCI: total capital investment
IRR: internal rate of return

Table 9 compares the economics of the full N-R HES configuration to those of an NGCC generator sized at 50 MW. Because the NGCC is flexible, it only runs when the price of electricity is greater than $0/MWh. We assumed that the nuclear reactor does not have that flexibility, but it does not need as much flexibility because the fuel cost is a much smaller fraction of the overall cost than for an NGCC. Note that the NGCC also has a negative NPV because the projected electricity energy and ancillary service prices plus the capacity payments are insufficient to meet the 10% internal rate of return used for the financial calculations. Table 9 shows that, using our capital and operating cost assumptions and not including a cost of carbon, electricity produced in this scenario is more expensive than that produced using an NGCC. We assumed that the NGCC only produces electricity when the value of electrical energy is not $0/MWh; hence, it does not produce electricity (or pay for the natural gas necessary to produce it) during 704 hr/yr. The NGCC has a negative NPV because the sum of income from energy, ancillary service, and capacity payments does not cover its operating and capital costs, including a 10% discount rate. This indicates that the NGCC was included by the capacity expansion model at a lower discount rate, lower natural gas price, or higher electricity price.

The full HTE configurations optimally produce no hydrogen at the reference case hydrogen price because the value of bidding into the regulation down market is greater during those hours. Because the full HTE configuration does not produce hydrogen, we did not develop a comparison case that produces both electricity and hydrogen.

Table 9. Financial Comparison Between Full HTE N-R HES Configuration and Electricity Generation Options

	NPV @ 10% Discount Rate	TCI	NPV/TCI Ratio	IRR	Annual Electricity Output (GWh)	Annual Hydrogen Production (metric ton)
Full HTE Configuration	-$111 million	$369 million	-0.30	5.3%	574	0
Nuclear Reactor + Thermal Power Cycle	-$60 million	$251 million	-0.24	6.4%	421	0
NGCC-Generating Electricity at 92% Capacity Factor	-$11 million	$47 million	-0.24	6.8%	403	0

For comparison, we performed the same analysis under the volatile electricity price set using the same methodology. Figure 12 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers at a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right). Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. The solid black dot in Figure 12 indicates the reference case electricity price vector (i.e., the electricity price multiplier is 1.0) and hydrogen price ($1.47/kg). To estimate the reference case hydrogen price, we estimated the cost of producing hydrogen via steam methane reforming of natural gas, as described in Section 2.7. Variations in natural gas prices will move the location of that dot and the movement can be estimated using Figure 5.

The results show that, under the volatile electricity prices, there are more profitable configurations than under the primary set of electricity prices, especially when the electricity price multiplier is close to 1.0. The reason is that the annual average electricity price is higher so sales of electricity give more configuration NPVs greater than $0. In addition, at lower electricity price multipliers, the optimal configuration more often includes the thermal power cycle with the nuclear reactor and HTE. The reason is that there are more high-price hours, and the electricity prices are higher during those hours in the volatile electricity price set than in the standard electricity price set. In addition, the full configuration is optimal under more electricity price multipliers and hydrogen prices under the volatile data set because the increased flexibility allows the full configuration N-R HES to take advantage of the hourly price differences for electricity.

Even though, at the reference case electricity and hydrogen prices, there are no profitable configurations under either the primary or volatile set of electricity prices, the hydrogen price necessary for the N-R HES to become profitable under the volatile set of electricity prices is down to $2.20/kg. As shown in Figure 5, $2.20/kg H_2 is competitive with natural-gas-produced hydrogen at a natural gas price of $11.00/MMBtu. At higher natural gas prices, prices in the electricity price set will also be higher because much of the electricity generation at the margin is produced from natural gas. Hence, if natural gas prices are higher than the projection of $6.98/MMBtu, the N-R HES is potentially profitable. Additional analysis is required to determine the level of profitability at various natural gas price projections.

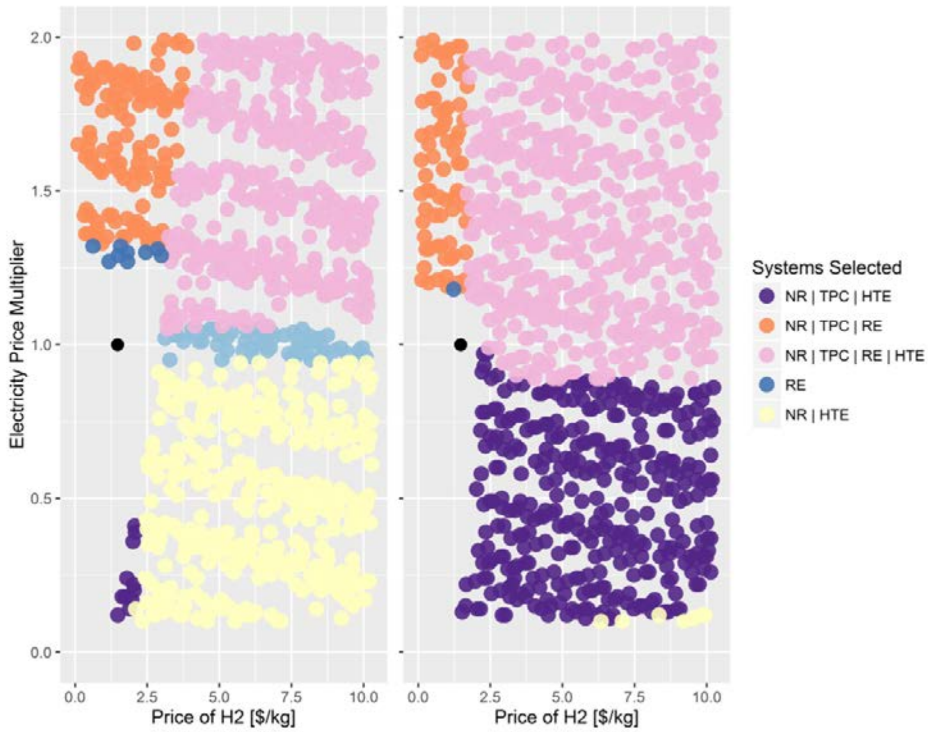

Figure 12. Optimal configurations for the HTE scenario with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

HTE: high temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Table 10 compares other financial results of two configurations under both the primary and volatile electricity price sets. The configuration on the left includes only the nuclear reactor and thermal power cycle. The configuration on the right includes HTE as well as the nuclear reactor and thermal power cycle. Under the primary electricity price set, the configuration with HTE does not optimally produce hydrogen; however, under the volatile price set, it does. Hence, when operated optimally, the configuration with HTE utilizes the available flexibility under the more volatile electricity price set. Also, note that the NPV difference between the configuration without HTE and the configuration with HTE is $33 million under the primary electricity price set and only $6 million under the volatile electricity price set. That difference indicates that there is a $27 million benefit for the flexibility when comparing the two electricity price sets.

Table 10. High Temperature Electrolysis Scenario Output Summary at Base Case Conditions for Two Configurations under Both Electricity Price Sets

Electricity Price Set	Primary	Volatile	Primary	Volatile
Configuration	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + High Temperature Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + High Temperature Electrolyzer (50 MWe)
Annual Electricity Output (GWh)	438	438	438	271
Annual Electricity Purchases (GWh)	0	0	0	15
Annual Hydrogen Production (metric ton)	N/A	N/A	0	4,719
TCI ($million)	$251	$251	$284	$284
NPV at 10% Discount Rate ($million)	-$60	-$35	-$93	-$41
IRR after 25 Years of Operation	6.4%	8.0%	4.9%	7.9%
NPV/TCI Ratio	-0.24	-0.14	-0.33	-0.15

TCI: total capital investment
IRR: internal rate of return

For the HTE scenario, no configurations are profitable, and the full N-R HES (LW-SMR nuclear reactor/thermal power cycle/wind power plant/HTE) is not the economically optimal solution under the reference case electricity and hydrogen prices. Under the volatile electricity price set, more configurations are profitable and many more of those configurations include the thermal power cycle than under the primary electricity price set. The reason is that the HTE subsystem provides income and the thermal power cycle enables flexibility to produce electricity when its price is high and hydrogen when the electricity price is low. Under the primary electricity price set, that value is not as great as under the volatile price set.

From these results, neither the full HTE N-R HES configuration nor any alternative configurations for this scenario exceed the required cost of capital to have a positive NPV, but

N-R HES configurations with more flexibility have better financial results under volatile electricity prices than the less volatile prices. In addition, under the volatile electricity price set, if natural gas prices are \$11.00/MMBtu or greater, the configuration is profitable even without considering the impacts of those natural gas prices on electricity prices. Hence, we conclude that the N-R HES with HTE has the potential to be profitable if the electricity prices are more volatile than used in this study or the natural gas prices are higher than the projections used in this study.

3.1.2 Potential to Reduce GHG Emissions and Their Associated Costs

One of the key potential benefits of N-R HESs is the potential to reduce carbon dioxide, sulfur oxide, nitrogen oxide, and particulate emissions and, if emission costs are applied, the associated costs of those emissions. At the 3% discount rate and a social cost of carbon of \$61/metric ton CO_2e, the minimum selling price for hydrogen produced via steam methane reforming (including the social cost of carbon) is \$2.20/kg. The price duration curve for electrical energy is higher with a social cost of carbon than without, as shown in Figure 3.

Figure 13 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers from the basis including a cost of carbon of \$61/metric ton CO_2e and a capacity payment of \$50/kW-yr. Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. Note that the colors indicating the optimal configuration match those in Figure 6.

Even though the electricity price multiplier and the hydrogen price necessary for profitable configurations both went down, there is no profitable configuration at the base case conditions of \$2.20/kg H_2 and an electricity price multiplier of 1.0 from a basis of electrical energy prices with the \$61/metric ton CO_2e cost of carbon. The black dot in Figure 13 indicates the base case conditions. As with the estimates without a cost of carbon, variations in natural gas prices will move the location of that dot and the movement can be estimated using Figure 5.

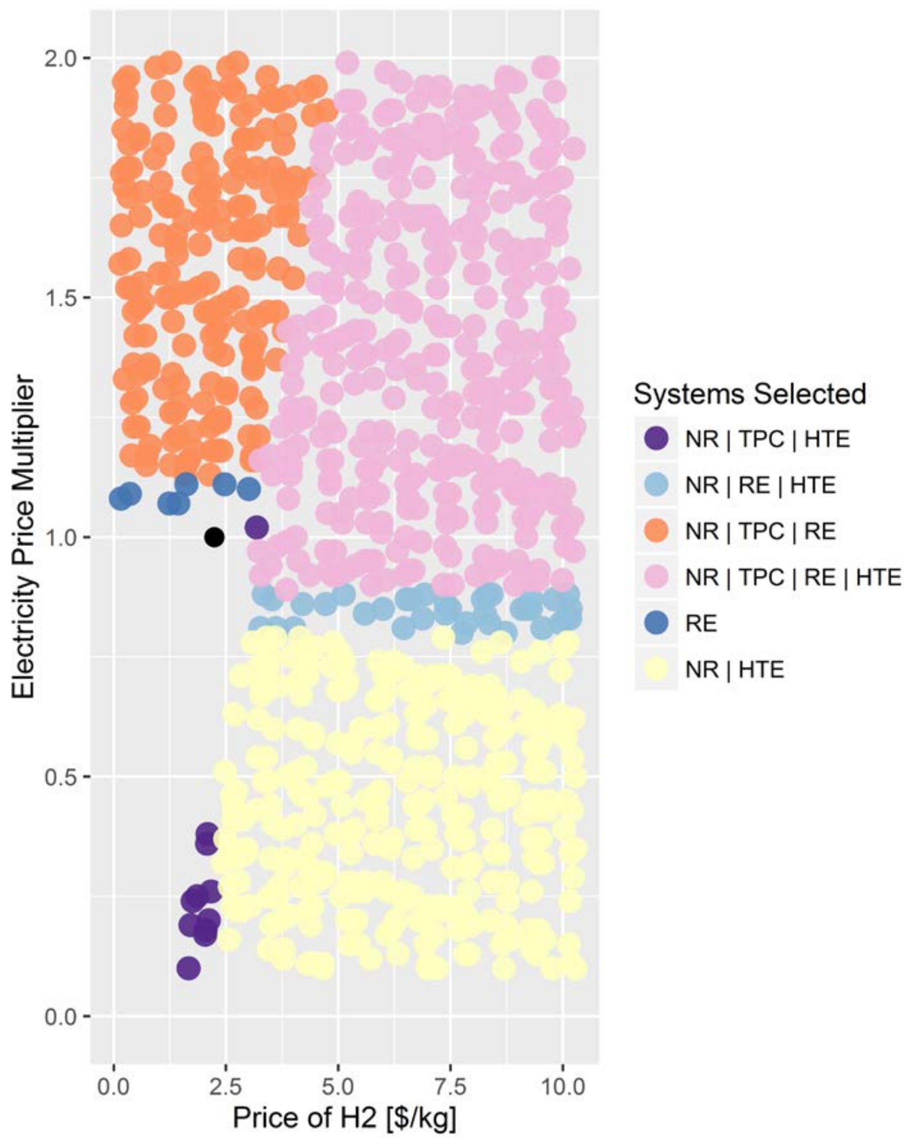

Figure 13. Optimal configurations for the HTE scenario with a $61/metric ton CO_2e cost of carbon

HTE: high temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
$50/kW-yr capacity payments. Solid black dot at $2.20/kg and 1.0 indicates reference case hydrogen and electricity prices with a $61/ton CO_2e cost of carbon.

Based on these results, we conclude that at a $61/metric ton CO_2e cost of carbon, no configuration in this scenario is more profitable than producing hydrogen via steam methane reforming; thus, with that cost of carbon, carbon emissions from hydrogen production are not reduced with this technology. Other drivers could increase that marginal hydrogen price to a point where some or all of the N-R HES configurations analyzed here would be profitable. Those include a cap on natural gas use, a clean hydrogen standard, or a limitation on natural gas technologies such as fracking to limit geologic impacts. If one or more of those drivers are implemented, the N-R HESs analyzed here could reduce GHG emissions.

3.1.3 Potential to Support Resource Adequacy

We tested the hypothesis that N-R HESs can support electricity resource adequacy while maximizing production of a more profitable industrial product with sufficient incentives (i.e., a capacity payment that is sufficiently high). In this analysis, no HTE configurations are profitable at a capacity payment of $50/kW-yr and the base case hydrogen price. Figure 14 shows the price ranges where capacity payments are received at three different capacity payment levels: $50/kW-yr, $100/kW-yr, and $150/kW-yr.

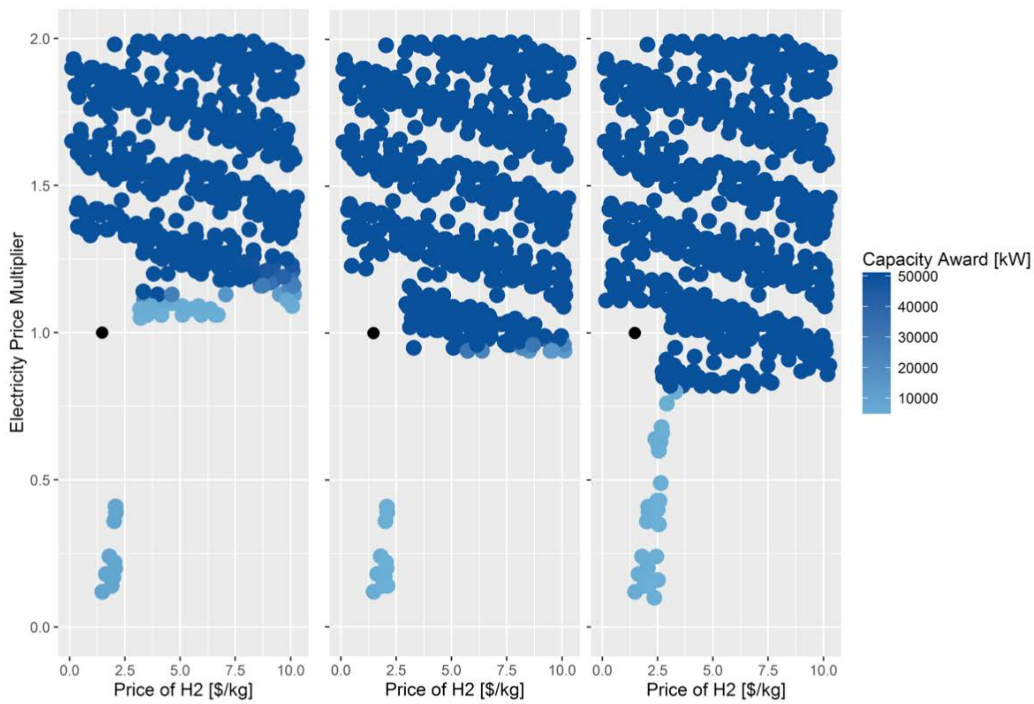

Figure 14. Optimal capacity payments awarded for the HTE scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Increased capacity payments increase the incentive to build reliable electricity generation. As shown in Figure 15, increased capacity payments result in lower hourly electricity prices necessary for optimal configurations to include thermal power cycles. Increasing the capacity payment from $50/kW-yr to $100/kW-yr reduces the electricity price multiplier necessary to include the nuclear reactor and thermal power cycle in the optimal configuration, from 1.3 to 1.25 when the hydrogen price is less than $3.00/kg. Likewise, that capacity payment increase reduces the electricity price multiplier necessary to include the thermal power cycle in the optimal configuration, from 0.55 to 0.45 when the hydrogen price is greater than $3.00/kg. Increasing the capacity payment to $150/kW-yr further reduces the electricity price multiplier necessary for the nuclear reactor/thermal power cycle to be in the optimal configuration; however, still higher capacity payments are necessary for the optimal configuration at the base case parameters to include the nuclear reactor/thermal power cycle.

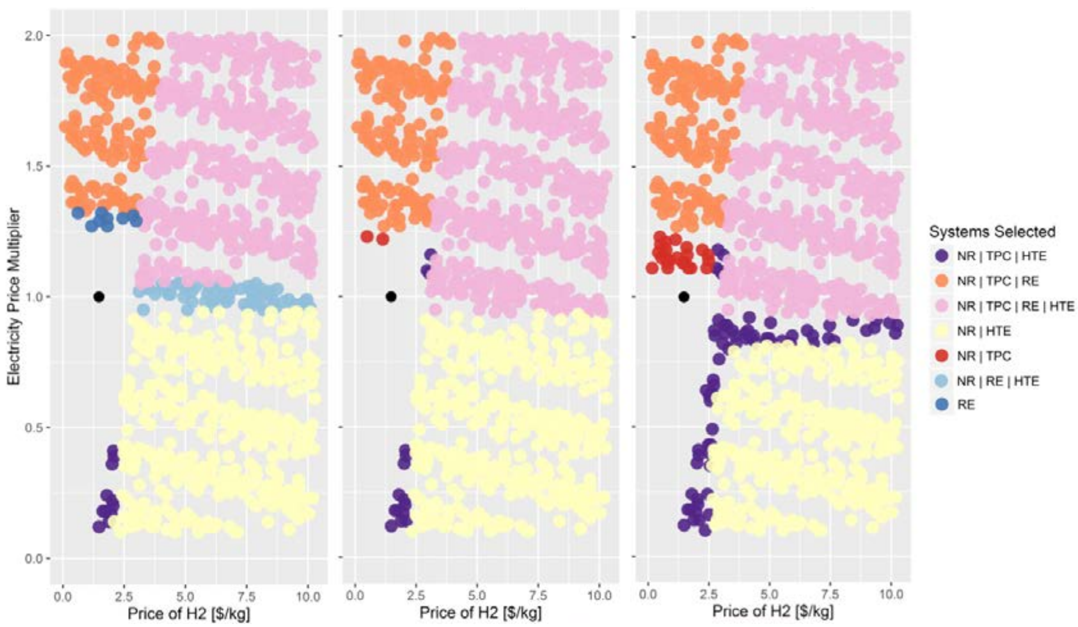

Figure 15. Optimal configurations for the HTE scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)

HTE: high temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Higher capacity payments lead to increased electricity generation during peak hours (i.e., those required to receive the capacity payment). Figure 16 shows the optimal annual electricity production under the three capacity payments. It shows that, at higher capacity payments, electricity is generated up to the highest hydrogen prices considered in the analysis. The result indicates that this N-R HES can support grid resource adequacy as long as both the hydrogen price and the capacity payment are sufficient, but the baseline electrical energy and hydrogen prices are not sufficient, even at the highest capacity payments.

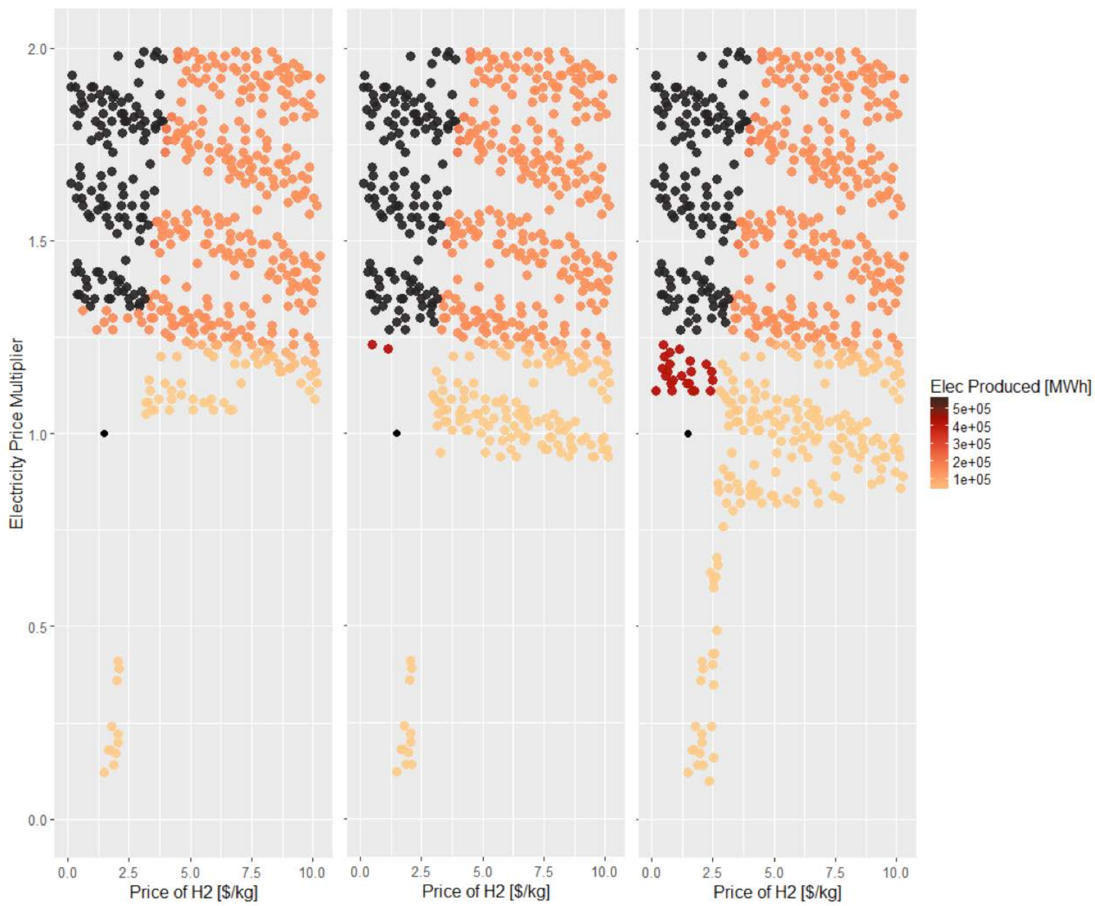

Figure 16. Optimal annual electricity production for HTE scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

3.1.4 Potential for Flexibility to Increase Profitability

We tested the hypothesis that, at some combinations of electricity and hydrogen prices, N-R HESs will be more profitable than uncoupled configurations because they can produce electricity when its price is high and hydrogen when the price of electricity is low.

Based on this analysis, some configurations are more profitable because they can adjust their product to follow market prices. In Figure 16 and Figure 17, that situation is most noticeable at the highest hydrogen prices, when hydrogen is sold during some hours (both light and dark orange dots) because its value is higher than that of electricity (especially during hours when the price of electricity is $0/MWh). Figure 17 shows that, under the volatile electricity price set, there are more conditions where a small amount of electricity is optimally produced at low electricity price multipliers and high hydrogen prices. In addition, under the volatile electricity price set, at electricity price multipliers above 1.2 and hydrogen prices between $2.50/kg and $3.75/kg, the optimal N-R HES switches between electricity and hydrogen, as shown by the red dots. Hence, the flexibility provided by N-R HESs could increase profitability, especially under volatile electricity price sets.

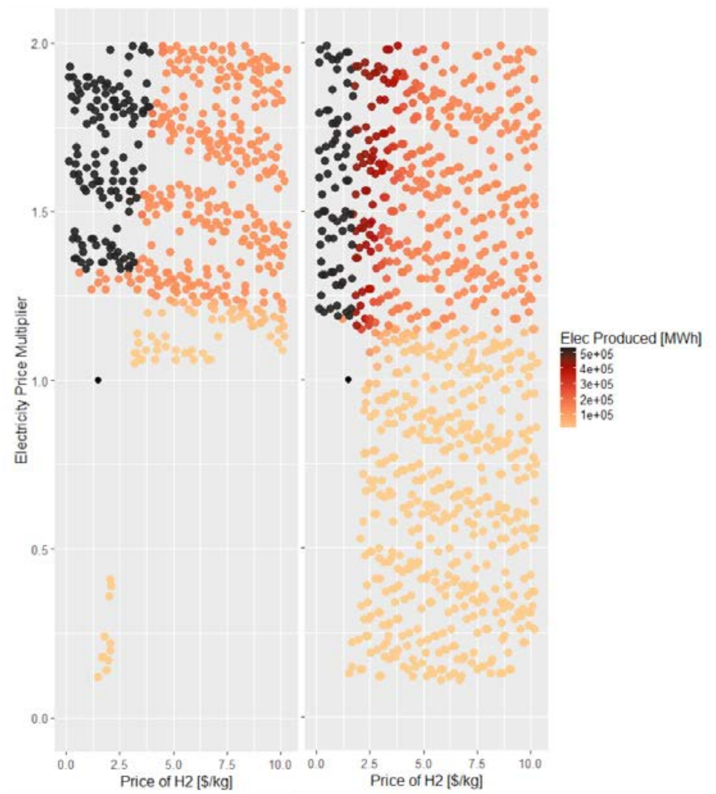

Figure 17. Optimal annual electricity production for HTE scenario at various hydrogen prices and electricity price multipliers with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

3.2 Results of the Low Temperature Electrolysis Scenario

The LTE scenario involves four primary subsystems: (1) a nuclear reactor, (2) a thermal power cycle that can be associated with the nuclear reactor, (3) a wind power plant, and (4) an LTE subsystem that uses electricity exclusively to produce hydrogen. The LTE subsystem differs from the HTE subsystem in that its only energy source is electricity whereas the HTE subsystem has both electricity and heat as energy sources; thus, the LTE configuration is simpler because heat from the nuclear reactor can only be used to generate electricity.

We set the same maximum size for the nuclear reactor, the thermal power cycle, the wind power plant, and the LTE subsystem—50 MWe—to show the impacts of each subsystem clearly. The thermal power cycle efficiency of 30% implies a thermal capacity of 167 MWt for the nuclear reactor.

As with the HTE scenario, we used REopt to identify the optimal size of each subsystem and the optimal energy dispatch on an hourly basis. The model allows for energy to be split (i.e., some of the electricity from the wind power plant and/or thermal power cycle can be used by the LTE subsystem and the remainder can sold) during any hour as long as that solution is optimal for the N-R HES.

3.2.1 Potential Profitability

We analyzed the potential profitability of the LTE N-R HES by varying the prices of the electricity and hydrogen products and using REopt to calculate the optimal set of subsystems and internal dispatch, as discussed in Section 2.1. We varied the hydrogen price from $0/kg to $10/kg to identify how various prices might impact the results. As in previous analyses, we also varied the price of electricity using a multiplier that affected the electricity energy price for all 8,760 hours in the year.[*] For each run, the multiplier was randomly assigned a value between 0 and 2 so the electrical energy price in that run could be $0/MWh for every hour of the year, twice the electrical energy price developed for the reference case for every hour, or any other multiplied value between 0 and 2. The electricity price multiplier could be considered a proxy for (1) the difference between marginal generation costs and market prices (due to bidding strategies and market settlement) and (2) uncertainty in the natural gas price because natural gas is on the operating cost margin for the vast majority of the year. [76] All other parameters were kept at the reference values unless noted otherwise (i.e., for a sensitivity). Note that the analysis methodology we used presumes perfect foresight of all expenses, the renewable resource, and product prices throughout the project financial life.

Figure 18 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers on the primary set of electricity prices at a capacity payment of $50/kW-yr. Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. The results of this analysis show:

- The area in Figure 18 with no dots indicates that none of the configurations are profitable (i.e., the NPV is less than zero for all configurations under those conditions). That area is where the electricity price multiplier is below 1.25 and the hydrogen price is below $1.50/kg–$3.75/kg depending upon the price of electricity. Note that the minimum hydrogen price where a profitable configuration is possible depends on the price of electricity. This is because electricity can be purchased to produce hydrogen and that option becomes increasingly profitable as the price of electricity goes down.
- If the electricity price multiplier is between 1.25 and 1.35 and the hydrogen price is below $3.75/kg (as shown by the dark blue dots), the only profitable configuration is the wind power plant without any other subsystems. Neither the price of electricity, including a possible capacity payment, nor the price of hydrogen is sufficient to overcome the capital and operating costs of the LTE subsystem or the nuclear reactor with a thermal power cycle.
- If the electricity price multiplier is above 1.35, the hydrogen price is below $5.25/kg, and the prices of hydrogen and electricity are in the range indicated by the orange dots, the nuclear reactor with a thermal power cycle has sufficient income from selling electricity and receiving a capacity payment to be profitable. In addition, the wind power plant is profitable, so the configuration includes the nuclear reactor, the thermal power cycle, and

[*] Prices of ancillary services (reserves, flex reserves, and regulation up and down) were not multiplied because a change in price has little effect on the operational selection and optimization.

the wind power plant. This configuration of the N-R HES does not produce any hydrogen.

- If the electricity price multiplier is below 0.95 and the hydrogen price is above $1.50/kg and in the range shown by the yellow dots, the optimal configuration is the LTE subsystem by itself. The LTE subsystem uses purchased electricity exclusively to produce hydrogen.
- If the electricity price multiplier is between 0.95 and 1.1 and the hydrogen price is above $3.75/kg (as shown by the light blue dots), the optimal configuration includes the LTE subsystem and the wind power plant. The LTE subsystem produces hydrogen using the electricity generated by the wind power plant supplemented by grid electricity when the wind is not blowing.
- If the electricity price multiplier is between 1.15 and 1.3, the hydrogen price is above $3.75/kg, and in the range indicated by the purple dots, the optimal configuration includes the nuclear reactor, thermal power cycle, and LTE. In the optimal configuration, LTE uses the electricity generated by the nuclear reactor/thermal power cycle except during the hours when electricity is sold to receive a capacity payment.
- If the electricity price multiplier is around 1.10 or above 1.25, the hydrogen price is above $3.75/kg and in the range indicated by the pink dots, the optimal configuration includes the nuclear reactor, thermal power cycle, LTE, and wind power plant. This is the full configuration for this scenario.

Note that configurations indicated by the yellow, light blue, and pink dots include LTE subsystems and produce electricity. The left side of those configurations forms a diagonal line; the hydrogen price-electricity price multiplier combinations to the right of that line include LTE subsystems and produce hydrogen and combinations to the left of that line do not include LTE subsystems and do not produce hydrogen.

The solid black dot in Figure 18 indicates the reference case electricity price vector (i.e., the electricity price multiplier is 1.0) and hydrogen price ($1.47/kg). To estimate the reference case hydrogen price, we estimated the cost of producing hydrogen via steam methane reforming of natural gas, as described in Section 2.7. Variations in natural gas prices will move the location of that dot and the movement can be estimated using Figure 5.

The separation between the configurations with pink and orange dots depends on both the hydrogen and electricity prices because, as the electricity price multiplier is held constant and the hydrogen price increases (horizontal on Figure 18), hydrogen becomes more valuable than electricity. In that case, use of electricity for LTE displaces sales of that electricity. Likewise, as the hydrogen price is held constant and the electricity price increases, electricity becomes more valuable than hydrogen and the N-R HES's optimal configuration produces and sells electricity instead of hydrogen. The line separating the yellow dots from the configurations with no dots similarly depends on both the hydrogen and electricity prices.

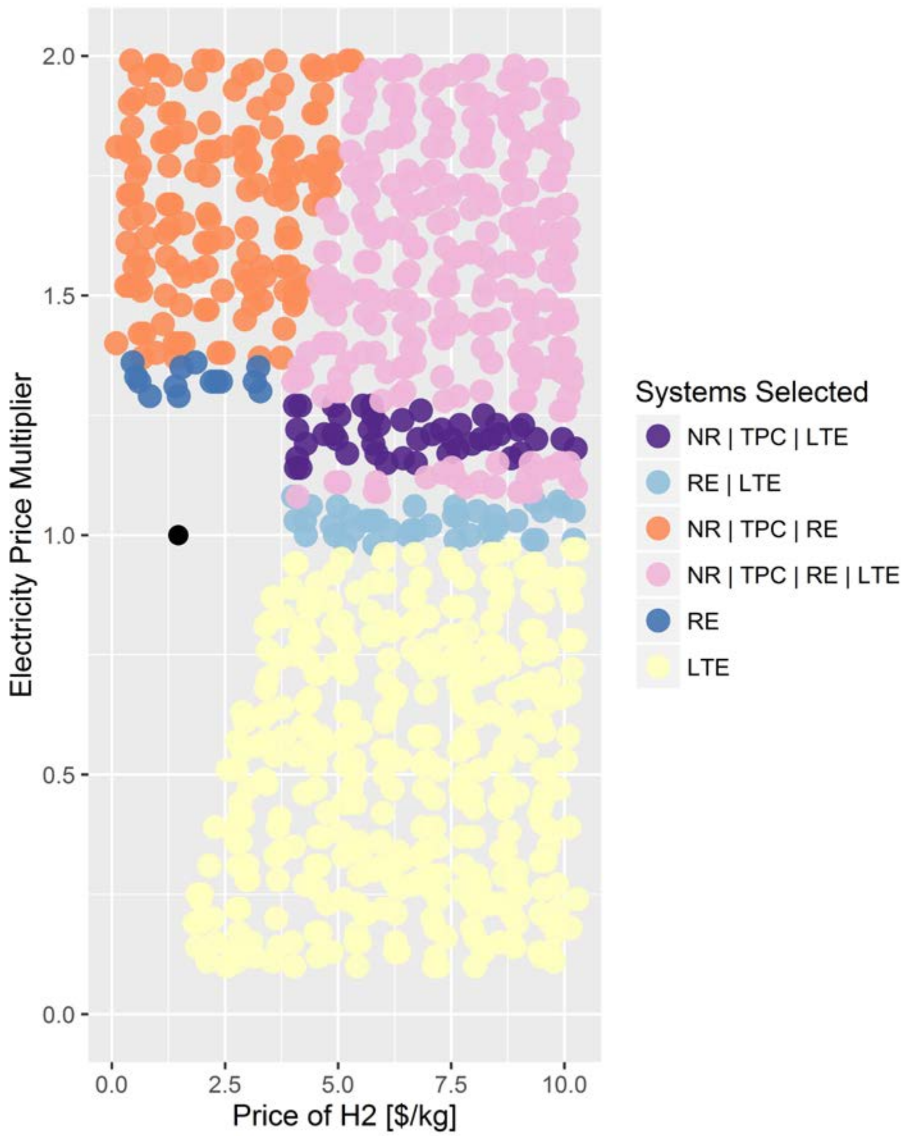

Figure 18. Optimal configurations for the LTE Scenario with a capacity payment of $50/kW-yr

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 19 and Figure 20 expand upon the information in Figure 18. Figure 19 shows the optimal amount of electricity purchased from the grid and identifies the reason that the pink dots in Figure 18 are split above and below the purple dots. At electricity price multipliers less than 0.95, the only subsystem included in optimal configurations is the LTE subsystem; therefore, only purchased electricity is used to generate hydrogen. At electricity price multipliers between 0.95 and 1.15–1.2 (depending upon the price of hydrogen), less electricity is purchased because the optimal configuration includes both the wind power plant and the LTE subsystem; therefore, the wind power plant provides some of the electricity. During some hours when the wind is blowing, no electricity needs to be purchased. The value of hydrogen production is sufficient so that, during the hours when the wind is not blowing, purchasing electricity to produce hydrogen is the economic option. At the electricity price multipliers between 1.15 and 1.3 there is a gap where no electricity is purchased because the optimal configuration includes a nuclear reactor and thermal power cycle that exclusively provide power to operate LTE. At the higher end of the electricity price range, the nuclear reactor and thermal power cycle are also included and they offset grid purchases. At electricity price multipliers greater than 1.25 and hydrogen prices above $3.75/kg, electricity is purchased during some hours during the year. The number of those hours is impacted by the variability of electricity energy and ancillary service prices and the variability of wind production.

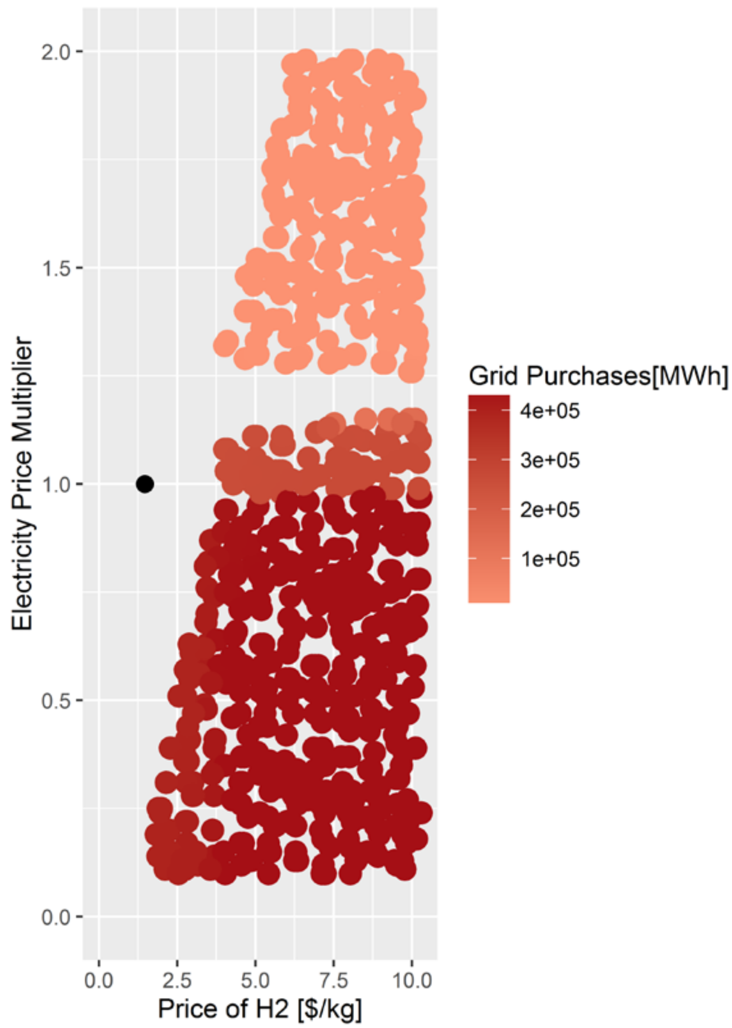

Figure 19. Optimal electricity purchases for the LTE scenario with a capacity payment of $50/kW-yr

Figure 20 shows the capacities of the subsystems included in each configuration. The nuclear reactor and thermal power cycle always have the same capacity because, in this scenario, the nuclear heat can only be used to generate electricity. Note that, under most configurations in this scenario, when a subsystem is included in the optimal configuration it is optimally at its maximum capacity. The exceptions are at points where the nuclear reactor/thermal power cycle and/or the wind plant are not in the optimal configuration. Those ranges are impacted by the hourly value of electricity and when wind generation of electricity might be slightly more profitable than nuclear generation of electricity.

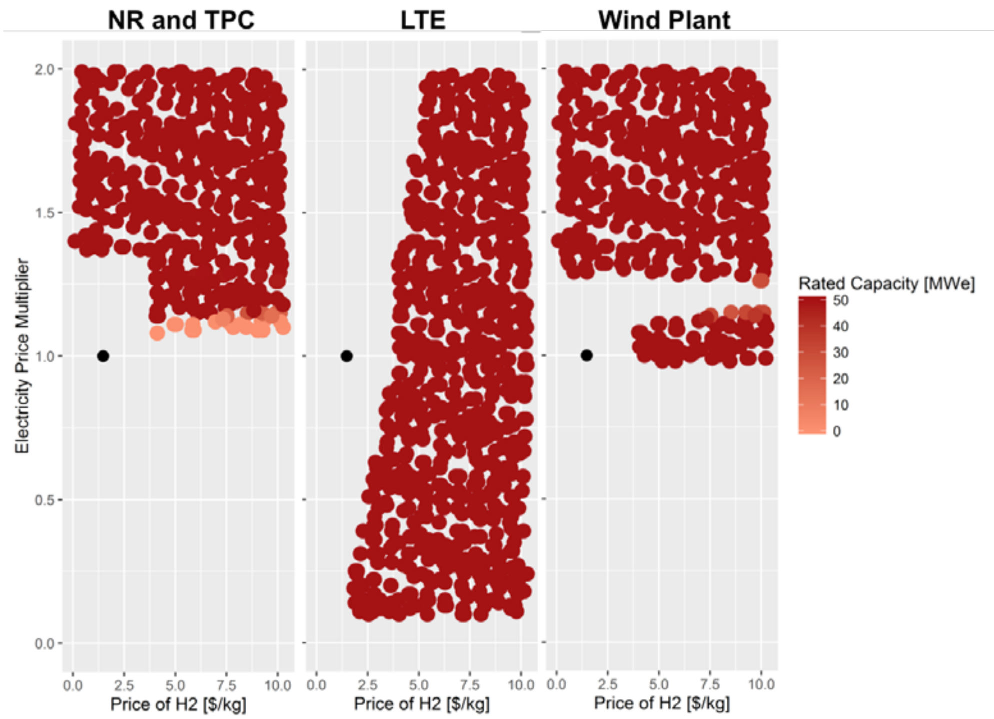

Figure 20. Optimal capacities of each subsystem for the LTE scenario with a capacity payment of $50/kW-yr

NR: nuclear reactor
TPC: thermal power cycle
LTE: low temperature electrolysis subsystem
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 21 shows the optimal product mix based on each optimal configuration shown in Figure 18. The black dots in the left graph in Figure 21 indicate the range of electricity price multipliers and hydrogen prices at which electricity generation is maximized from both the wind power plant and the nuclear reactor/thermal power cycle (and at which hydrogen is not produced). Immediately below that set of dots (i.e., where the electricity price multiplier is between 1.25 and 1.3 and the hydrogen price is below $3.75/kg—also shown by the dark blue dots in Figure 18), the electricity price is only sufficient for the wind power plant to be profitable. Therefore, annual electricity generation is much lower because the optimal configuration does not include the nuclear reactor/thermal power cycle.

The darker orange dots in the left graph in Figure 21 indicate the range where electricity sales are optimally reduced because some of the electricity is used in LTE to produce hydrogen. Electricity sales are further reduced in the lighter orange dots because the wind power plant is not included in the optimal configuration (as discussed above).

The graph on the right of Figure 21 shows that hydrogen production is near its maximum in most configurations that include LTE. During some hours, electricity is sold instead of used to produce hydrogen (as shown by the lighter orange dots in the left graph). The impact on annual hydrogen production is minimal.

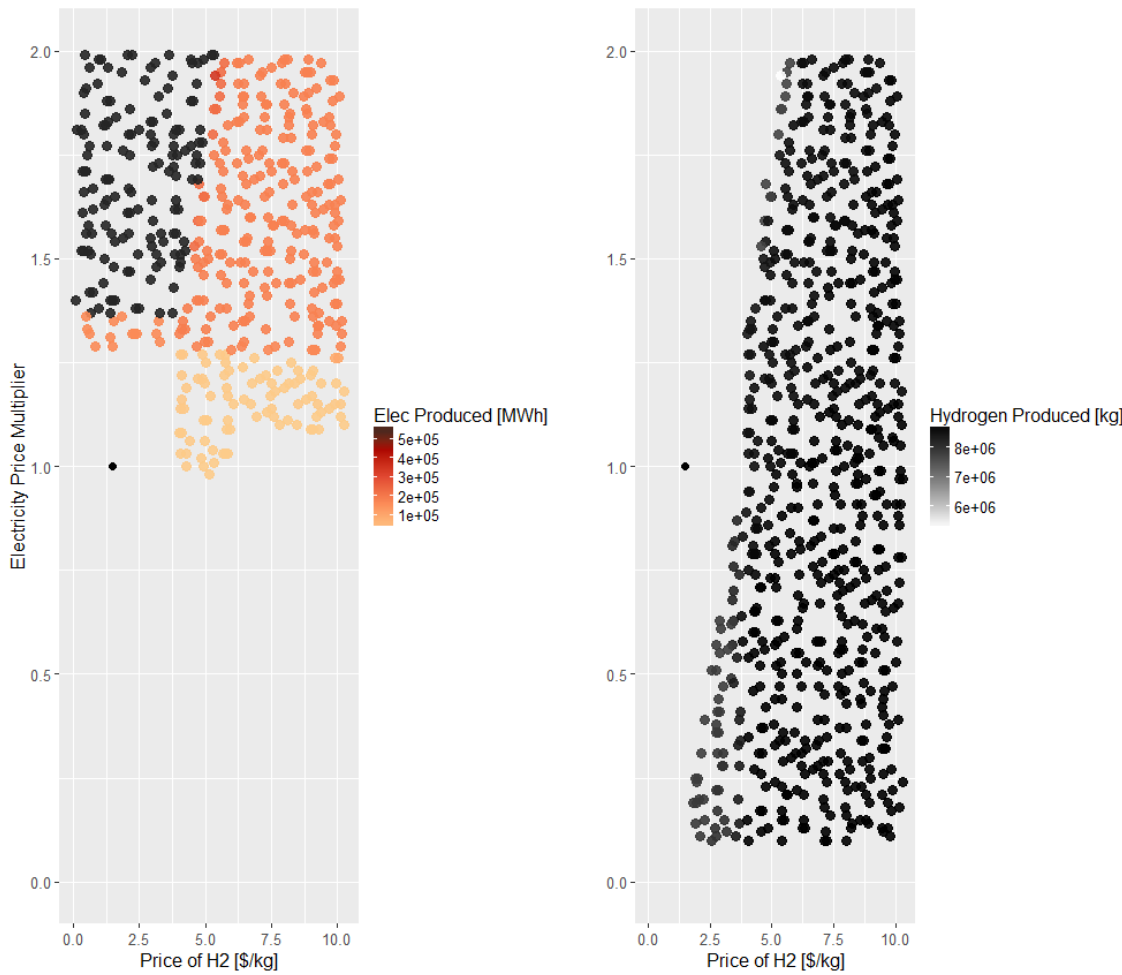

Figure 21. Optimal annual product generation for the LTE scenario at various hydrogen prices and electricity price multipliers

Electricity is on the left; darker colors indicate greater generation. Hydrogen is on the right. Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 22 shows the optimal capacity payment expectation. The LTE scenario optimally receives the maximum capacity payment in most cases the nuclear reactor/thermal power cycle is included (see the leftmost graph in Figure 20), even if that is the only electricity it generates each year (see the lighter orange dots in the left graph in Figure 21). The only exception is the lower pink range in Figure 18 (the lighter colored dots in Figure 22). In that range, it is optimal to balance wind generation with nuclear generation at some level but not the full 50 MW because the value of producing hydrogen from nuclear energy is higher than the value of electricity, even with the capacity payment.

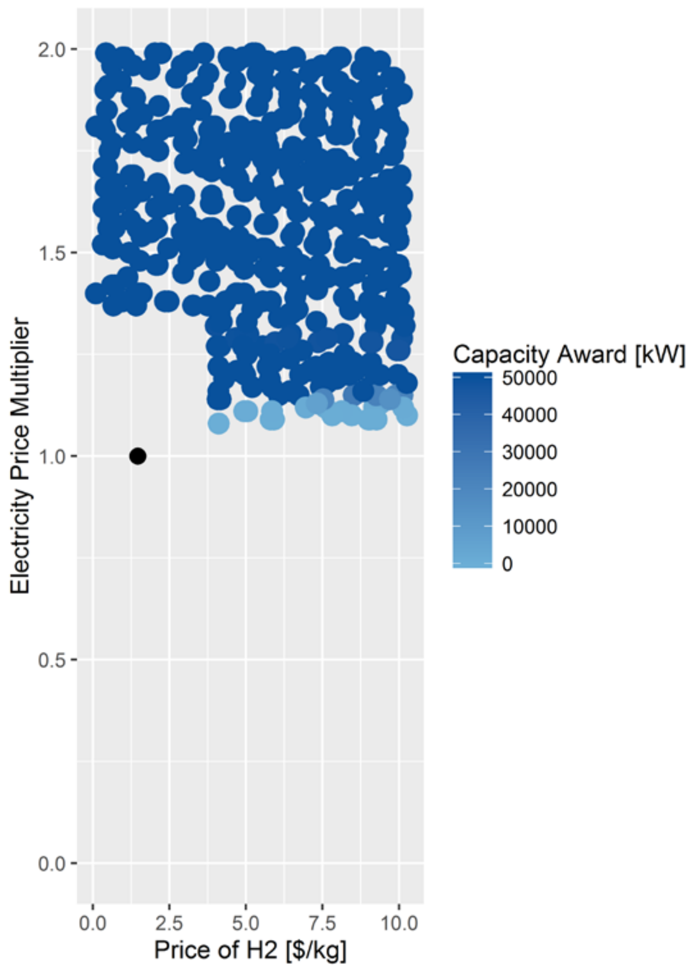

Figure 22. Optimal capacity payments awarded for the LTE scenario at various hydrogen prices and electricity price multipliers

Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 23 shows the NPVs for the optimal configurations shown in Figure 18. Note that profitability increases more dramatically with increasing hydrogen prices than with increasing electricity prices.

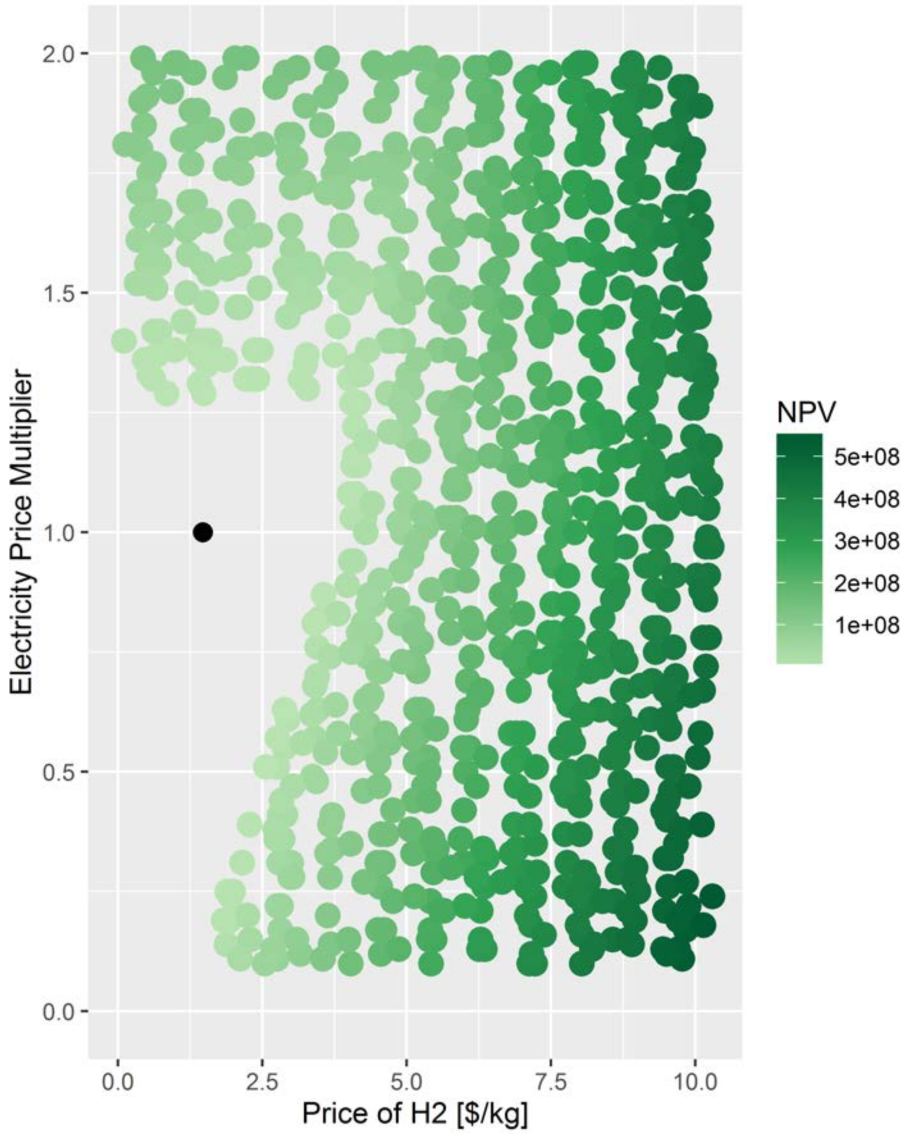

Figure 23. Optimal NPVs awarded for the LTE scenario at various hydrogen prices and electricity price multipliers

Electricity pricing based on AEO Reference Case and $50/kW-yr capacity payments.

Darker shades indicate higher NPVs.

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Table 11 provides the present values of all the annual revenues and expenses under the base case parameters. Note that none of these configurations is identified as profitable. The first configuration includes the LTE subsystem alone. In our simulations, the LTE subsystem does not purchase electricity to make hydrogen because when the price of electrical energy is above $0/MWh, the cost of electricity is greater than the income from hydrogen at the base case electricity prices and hydrogen production. In addition, when the price of electricity is $0/MWh, the LTE subsystem can receive more income from providing regulation down ancillary services than it can from producing hydrogen. The LTE subsystem is allowed to provide regulation down reserves because it can add load resulting in a reduction in net generation. The second configuration is the nuclear and thermal power cycle with the wind power plant. In the third configuration, the LTE subsystem is added to the nuclear reactor and thermal power cycle. The final configuration includes the wind power plant as well as the other subsystems—the full N-R HES. In the last two configurations, over the course of the year, the N-R HES could both purchase and sell electricity because sales and purchases could be at different times.

Table 11. Low Temperature Electrolysis Scenario Present Values at Base Case Conditions for Four Configurations

Configuration	Low Temperature Electrolyzer (50 MWe) Present Value ($million)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) Present Value ($million)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Low Temperature Electrolyzer (50 MWe) Present Value ($million)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe) + Low Temperature Electrolyzer (50 MWe) Present Value ($million)
Nuclear Plant				
Reactor Capex	$0	-$186	-$186	-$186
Nuclear Fixed O&M	$0	-$55	-$55	-$55
Thermal Power Cycle				
Thermal Power Cycle Capex	$0	-$65	-$65	-$65
Wind Power Plant				
Capex	$0	$0	$0	-$84
Fixed O&M	$0	$0	$0	-$27
Low Temperature Electrolyzer				
Capex	-$31	$0	-$31	-$31
Fixed O&M	-$25	$0	-$25	-$25
Revenue				
Purchased Electricity	$0	$0	$0	$0
Hydrogen Revenue	$0	$0	$0	$0
Capacity Payments	$0	$29	$29	$29
Electricity Revenue	$0	$250	$250	$345
Ancillary Services	$25	$0	$25	$25
Taxes	$6	-$33	-$27	-$28
NPV	-$25	-$60	-$85	-$103

Capex: capital expenditure
Negative values indicate expenses and positive indicate income

Table 12 compares other financial parameters of the nuclear reactor/thermal power cycle configuration and the alternatives identified in Table 11. At -$25 million, the NPV for the LTE subsystem alone is much lower than the configurations with additional subsystems; however, the NPV is so low because the capital expense is low. The LTE subsystem alone also has what would be a negative internal rate of return because the cash flow is negative during all years. Even though three of the configurations include LTE subsystems, they do not produce hydrogen even during hours when the electricity price is $0/MWh because they optimally bid into the regulation down market during those hours.

Table 12. Low Temperature Electrolysis Scenario Output Summary at Base Case Conditions for Four Configurations

Configuration	Low Temperature Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Low Temperature Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Wind Power Plant (50 MWe) + Low Temperature Electrolyzer (50 MWe)
Annual Electricity Output to Grid (GWh)	0	438	438	592
Annual Electricity Purchases (GWh)	0	0	0	0
Annual Hydrogen Production (metric ton)	0	N/A	0	0
TCI ($million)	$31	$251	$282	$366
NPV at 10% Discount Rate ($million)	-$25	-$60	-$85	-$103
Payback Period (years)	N/A	N/A	N/A	N/A
IRR after 25 years of operation	N/A *	6.4%	5.4%	5.6%
NPV/TCI Ratio	-0.82	-0.24	-0.30	-0.28

TCI: total capital investment
IRR: internal rate of return
* IRR cannot be calculated for the configuration with only the LTE subsystem because the cash flow is negative during all years.

Table 13 compares the economics of the full N-R HES configuration to those of an NGCC generator sized at 50 MW. Because the NGCC is flexible, it only generates electricity when the price of electricity is greater than \$0/MWh. We assumed that the nuclear reactor does not have that flexibility, but it does not need as much flexibility because the fuel cost is a much smaller fraction of the overall cost than for an NGCC. Note that the NGCC also has a negative NPV because the projected electricity energy and ancillary service prices plus the capacity payments are insufficient to meet the 10% internal rate of return used for the financial calculations. Table 13 shows that, using our capital and operating cost assumptions and not including a cost of carbon, electricity produced in this scenario is more expensive than that produced using an NGCC. We assumed that the NGCC only produces electricity when the value of electrical energy is not \$0/MWh; hence, it does not produce electricity (or pay for the natural gas necessary to produce it) during 704 hr/yr. The NGCC has a negative NPV because it the sum of income from energy, ancillary service, and capacity payments does not cover its operating and capital costs including a 10% discount rate. This indicates that the NGCC was included by the capacity expansion model at either a lower discount rate or under the assumption that it would have a higher capacity factor.

The full LTE configurations optimally produces no hydrogen at the reference case hydrogen price because the value of bidding into the regulation down market is greater during those hours. Because the full LTE configuration does not produced hydrogen, we did not develop a comparison case that produces both electricity and hydrogen.

Table 13. Financial Comparison Between Full LTE N-R HES Configuration and Electricity Generation Options

	NPV @ 10% Discount Rate	TCI	NPV/TCI Ratio	IRR	Annual Electricity Output (GWh)	Annual Hydrogen Production (metric ton)
Full LTE Configuration	-\$103 million	\$366 million	-0.28	5.6%	592	0
Nuclear Reactor + Thermal Power Cycle	-\$60 million	\$251 million	-0.24	6.4%	438	0
NGCC Generating Electricity at 92% Capacity Factor	-\$11 million	\$47 million	-0.24	6.8%	403	0

For comparison, we performed the same analysis under the volatile electricity price set using the same methodology. Figure 24 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers at a capacity payment of \$50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right). Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. The solid black dot in Figure 24 indicates the reference case electricity price vector (i.e., the electricity price multiplier is 1.0) and hydrogen price (\$1.47/kg). To estimate the reference case hydrogen price, we estimated the cost of producing hydrogen via steam methane reforming of natural gas, as described in Section 2.7.

The results show that more configurations are profitable under the volatile electricity prices than under the primary set of electricity prices, especially when the electricity price multiplier is close to 1.0. The reason is that the annual average electricity price is higher so sales of electricity give more configurations NPVs greater than $0. The profitable configurations without LTE subsystems (the orange and dark blue dots) show that impact most clearly. Many optimal configurations under the volatile price set that were not profitable under the base case electricity price set include the LTE subsystem (the pink, purple, light blue, and yellow dots). Those are profitable because the volatile price set has many more hours with low electricity prices than the base case price set. Hence, there is more income from selling electricity annually but a lower opportunity cost for producing and selling hydrogen during those hours when the electricity price is low.

Even though, at the reference hydrogen and electricity prices, there are no profitable configurations under either the primary or volatile set of electricity prices, the hydrogen price necessary for the N-R HES to become profitable under the volatile set of electricity prices is down to $2.50/kg. As shown in Figure 24, $2.50/kg H_2 is competitive with natural-gas-produced hydrogen at a natural gas price of $13.00/MMBtu. At higher natural gas prices, prices in the electricity price set will also be higher because much of the electricity generation at the margin is produced from natural gas. Hence, if natural gas prices are higher than the projection of $6.98/MMBtu, the N-R HES is potentially profitable. Additional analysis is required to determine the level of profitability at various natural gas price projections.

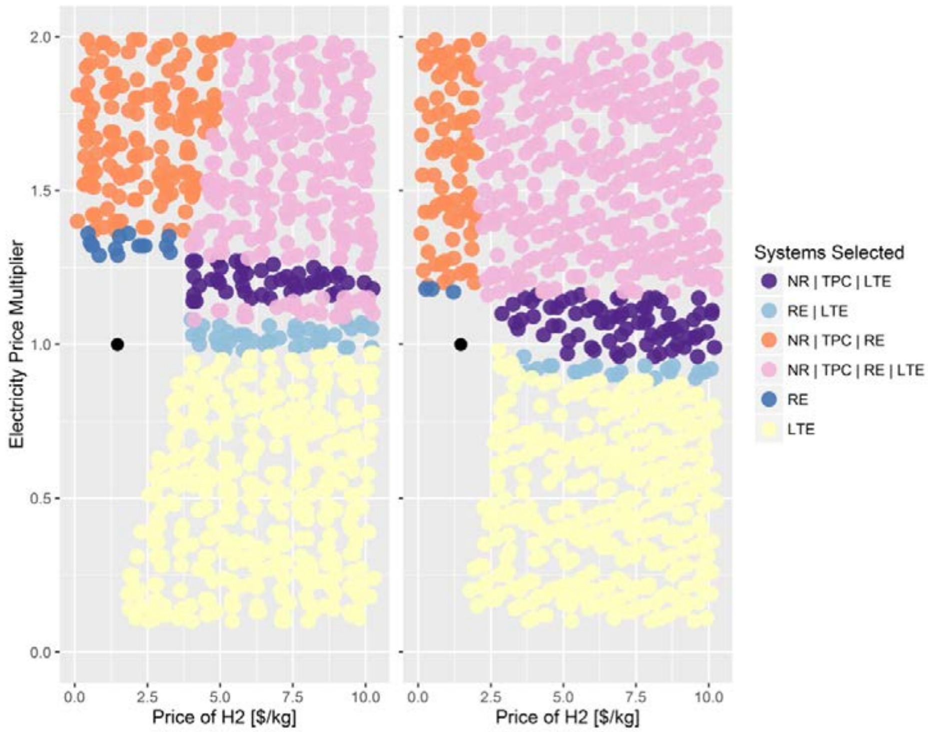

Figure 24. Optimal configurations for the LTE scenario with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 25 shows the optimal amount of electricity purchased from the grid under both electricity price sets. Under both price sets, at electricity price multipliers less than 0.95, the optimal configuration includes the LTE subsystem and, at higher electricity price multipliers, the wind farm. In those cases, the only product is hydrogen that is produced from grid electricity and electricity from the wind power plant when available. At higher electricity price multipliers, electricity is purchased under the primary electricity price set but not under the volatile price set because, under the primary electricity price set, the N-R HES is compensated for providing ancillary services to the grid. The optimal strategy includes provision of regulation up services during some hours of the year. To do so, the N-R HES purchases electricity and reduces use of that energy when called upon to provide those services. Because ancillary service prices were not available in the volatile price set, they were set to no value. Therefore, the optimal operations strategy under that price set does not include the electricity purchase at higher price multipliers that is included under the primary price set.

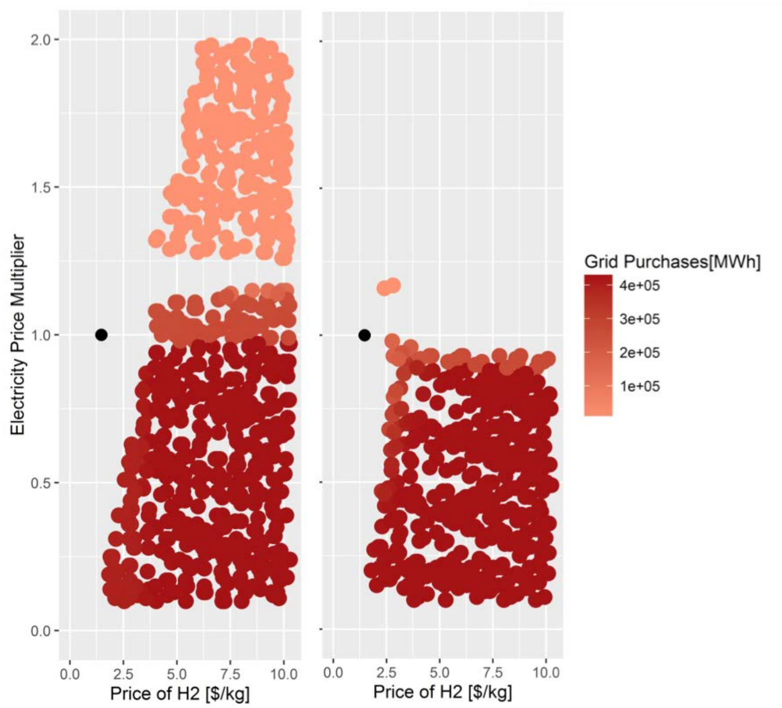

Figure 25. Optimal electricity purchases for the LTE scenario with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

Table 14 compares other financial parameters of two configurations between the primary and the volatile electricity price sets. The configuration compared on the left includes only the nuclear reactor and thermal power cycle. The configuration compared on the right includes the LTE subsystem as well as the nuclear reactor and thermal power cycle. Under the primary electricity price set, the configuration with the LTE subsystem does not optimally produce hydrogen; however, under the volatile price set, it does. Hence, when operated optimally, the configuration utilizes the available flexibility under the more volatile electricity price set. Also, note that the NPV difference between the configuration without the LTE subsystem and the configuration with the LTE subsystem is $25 million under the primary electricity price set and only $11 million under the volatile electricity price set. That difference indicates that there is a $14 million benefit for the flexibility when comparing the two electricity price sets.

Table 14. Low Temperature Electrolysis Scenario Output Summary at Base Case Conditions for Two Configurations under Both Electricity Price Sets

Electricity Price Set	Primary	Volatile	Primary	Volatile
Configuration	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Low Temperature Electrolyzer (50 MWe)	Nuclear Reactor (167 MWt) + Thermal Power Cycle (50 MWe) + Low Temperature Electrolyzer (50 MWe)
Annual Electricity Output (GWh)	438	438	438	280
Annual Electricity Purchases (GWh)	0	0	0	0
Annual Hydrogen Production (metric ton)	N/A	N/A	0	3,149
TCI ($million)	$251	$251	$282	$282
NPV at 10% Discount Rate ($million)	-$60	-$35	-$85	-$46
IRR After 25 Years of Operation	6.4%	8.0%	5.4%	7.6%
NPV/TCI Ratio	-0.24	-0.14	-0.30	-0.16

TCI: total capital investment
IRR: internal rate of return

For the LTE scenario, no scenarios are profitable and the full N-R HES (LW-SMR nuclear reactor/thermal power cycle/wind power plant/LTE) is not the economically optimal solution under the base case electricity and hydrogen prices. Under the volatile electricity price set, more configurations are profitable and, at the reference case conditions, configurations that include LTE subsystems result in less negative NPVs than those without the flexibility provided by the LTE subsystems.

From these results, neither the full LTE N-R HES configuration nor any alternative configurations for this scenario exceed the required cost of capital to have a positive NPV. The N-R HES configurations that include the LTE subsystem have better financial results under volatile electricity prices than the less volatile prices. In addition, under the volatile electricity price set, if natural gas prices are $13/MMBtu or greater, the configuration is profitable even without considering the impacts of those natural gas prices on electricity prices. Hence, we conclude that the N-R HES with LTE has the potential to be profitable if the electricity prices are more volatile than used in this study or the natural gas prices are higher than the projections used in this study.

3.2.2 Potential to Reduce GHG Emissions and Their Associated Costs

Figure 26 shows the optimal configuration selections for ≈1,000 combinations of hydrogen prices and electricity price multipliers from the basis, including a cost of carbon of $61/metric ton CO_2e and a capacity payment of $50/kW-yr. The price duration curve for electrical energy is higher with a social cost of carbon than without, as shown in Figure 3. The minimum selling price for hydrogen produced via steam methane reforming (including the social cost of carbon) is $2.20/kg. Hydrogen prices and electricity price multipliers for each run were independently and randomly sampled from a uniform distribution across the ranges. Note that the colors indicating the optimal configuration match those in Figure 18.

Even though the electricity price multiplier and the hydrogen price necessary for profitable configurations both went down, there is no profitable configuration at the base case conditions of $2.20/kg H_2 and an electricity price multiplier of 1.0 from a basis of electrical energy prices with the $61/metric ton CO_2e cost of carbon. The black dot in Figure 26 indicates the base case conditions. As with the case without a cost of carbon, variations in natural gas prices will move the location of that dot and can be estimated using Figure 5.

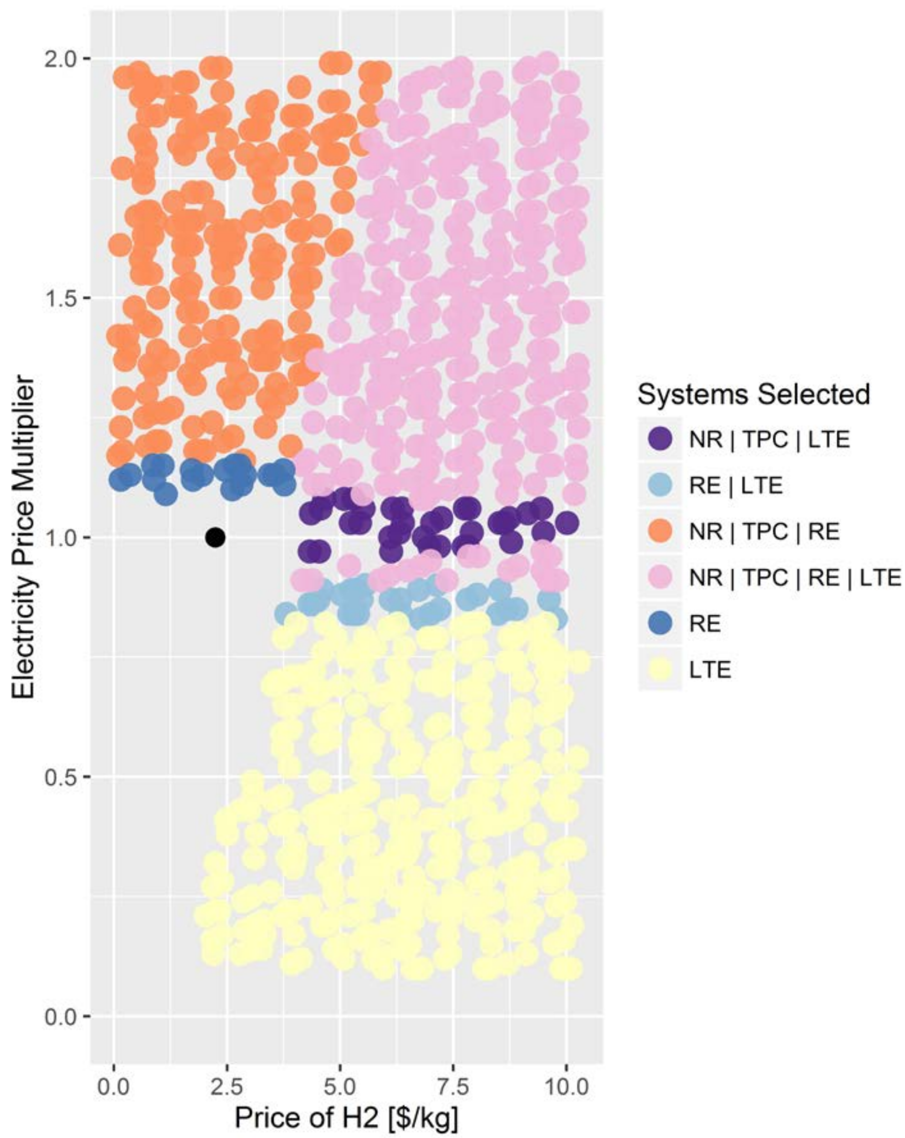

Figure 26. Optimal configurations for the LTE scenario with a $61/metric ton CO_2e cost of carbon

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
$50/kW-yr capacity payments. Solid black dot at $2.20/kg and 1.0 indicates reference case hydrogen and electricity prices with a $61/ton CO_2e cost of carbon.

Based on these results, we conclude that at a $61/metric ton CO_2e cost of carbon, no configuration in this scenario is more profitable than producing hydrogen via steam methane reforming; thus, with that cost of carbon, carbon emissions from hydrogen production are not reduced with this technology. Other drivers could increase that marginal hydrogen price to a point where some or all N-R HES configurations analyzed here would be profitable. Those include a cap on natural gas use, a clean hydrogen standard, or a limitation on natural gas technologies such as fracking to limit geologic impacts. If one or more of those drivers are implemented, the N-R HESs analyzed here could reduce GHG emissions.

3.2.3 Potential to Support Resource Adequacy

We tested the hypothesis that N-R HESs can support electricity resource adequacy while maximizing production of a more profitable industrial product with sufficient incentives (i.e., a capacity payment that is sufficiently high). In this analysis, the LTE Scenario did not select any configuration at a capacity payment of $50/kW-yr and base case hydrogen price. Figure 27 shows the price ranges where capacity payments are received at three different capacity payment levels: $50/kW-yr, $100/kW-yr, and $150/kW-yr.

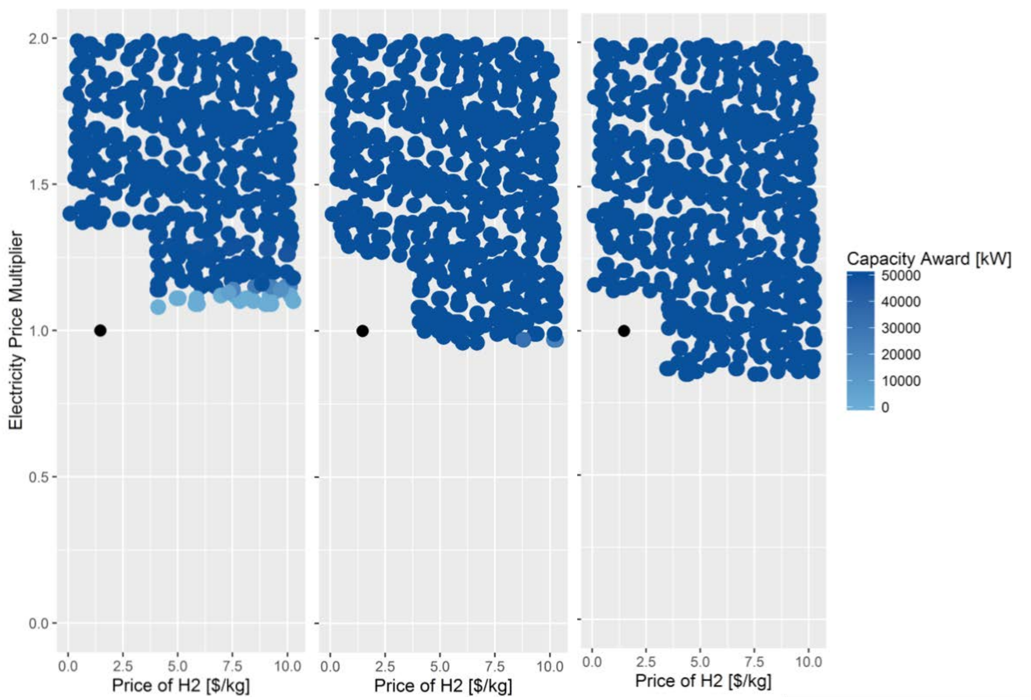

Figure 27. Optimal capacity payments awarded for the LTE Scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Increased capacity payments increase the incentive to build reliable electricity generation. As shown in Figure 28, increased capacity payments result in lower hourly electricity prices necessary for optimal configurations to include thermal power cycles. Increasing the capacity payment from $50/kW-yr to $100/kW-yr reduces the electricity price multiplier necessary to include the nuclear reactor and thermal power cycle in the optimal configuration, from 1.3 to 1.25 when the hydrogen price is less than $3.75/kg. Increasing the capacity payment to $150/kW-yr further reduces the necessary electricity price multiplier to 1.1.

Likewise, a $100/kW-yr capacity payment eliminates the configurations with the LTE subsystem and without the nuclear reactor and thermal power cycle when the price of hydrogen is greater than $3.75/kg. A $150/kW-yr capacity payment further reduces the electricity price multiplier to 0.8 for the nuclear reactor and thermal power cycle to be included in the optimal configuration when the price of electricity is greater than $3.75/kg. Higher capacity payments are needed for the optimal configuration at the base case parameters to include the nuclear reactor/thermal power cycle.

In most of the configurations that include the thermal power cycle, the maximum capacity payment is optimally received, as shown in Figure 27. The only exception is the $50/kW-yr capacity payment, at which point the small range with the full configuration where the electricity price multiplier is around 1.10 (the lower pink range in the left graph in Figure 28). In that range, the optimal capacity of the nuclear reactor and thermal power cycle are not their maximums (see Figure 20) because the value of the capacity payment is balanced against the value of hydrogen.

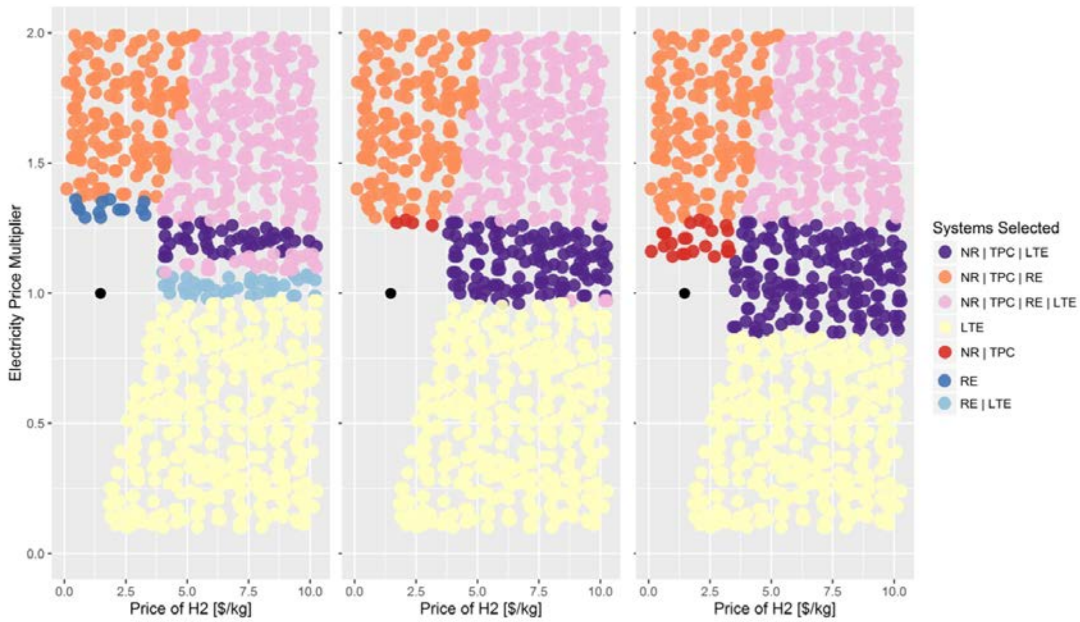

Figure 28. Optimal configurations for the LTE scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Higher capacity payments lead to increased electricity generation during peak hours (i.e., those required to receive the capacity payment). Figure 29 shows the optimal annual electricity production under the three capacity payments. It shows that, at higher capacity payments, electricity is generated up to the highest hydrogen prices considered in the analysis. The result indicates that this N-R HES can support grid resource adequacy as long as both the hydrogen price and the capacity payment are sufficient.

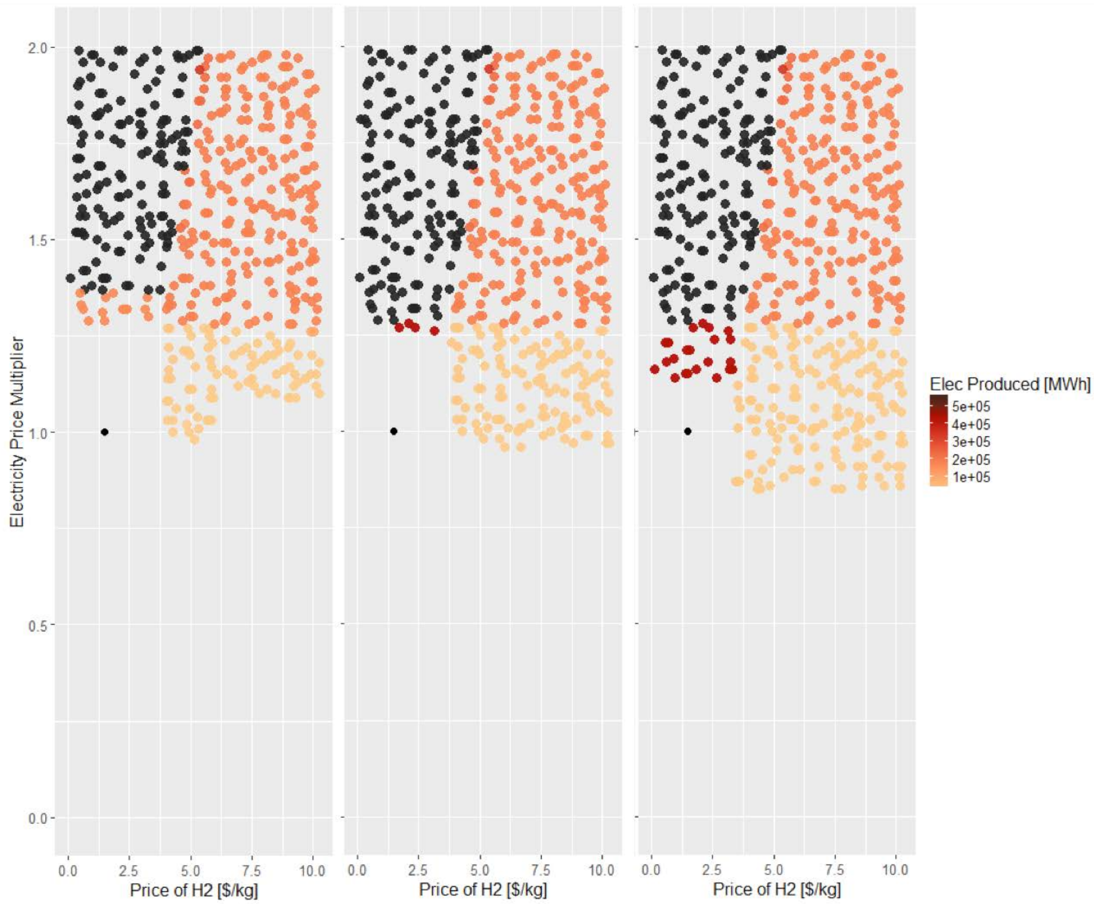

Figure 29. Optimal annual electricity production for LTE scenario at various hydrogen prices and electricity price multipliers at three levels of capacity payments

$50/kW-yr (left); $100/kW-yr (middle); $150/kW-yr (right)

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

3.2.4 Potential for Flexibility to Increase Profitability

We tested the hypothesis that, at some combinations of electricity and hydrogen prices, N-R HESs will be more profitable than uncoupled configurations because they can produce electricity when its price is high and hydrogen when the price of electricity is low.

Based on this analysis, some configurations are more profitable because they can adjust their product to follow market prices. In Figure 29 and Figure 30, that situation is most noticeable at the highest hydrogen prices, when hydrogen is sold during some hours (both light and dark orange dots) because its value is higher than that of electricity (especially during hours when the price of electricity is $0/MWh). Figure 30 shows that, under the volatile electricity price set, there are more conditions where a small amount of electricity is optimally produced at electricity price multipliers between 0.9 and 1.1 and high hydrogen prices. In addition, under the volatile electricity price set, at electricity price multipliers above 1.2 and hydrogen prices between $2.50/kg and $5.00/kg, the optimal N-R HES switches between electricity and hydrogen, as shown by the red dots. Hence, the flexibility provided by N-R HESs could increase profitability, especially under volatile electricity price sets.

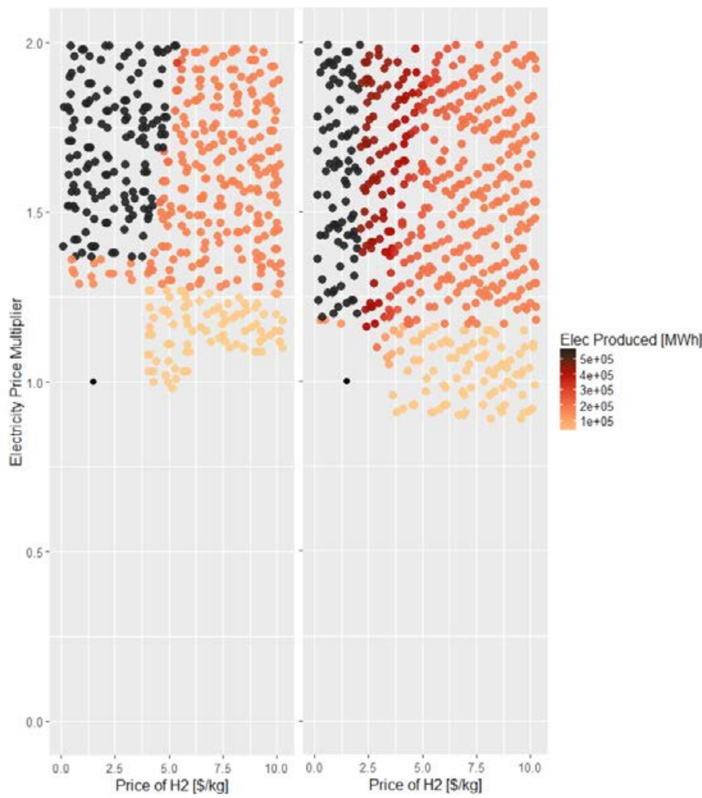

Figure 30. Optimal annual electricity production for LTE scenario at various hydrogen prices and electricity price multipliers with a capacity payment of $50/kW-yr under the primary electricity price set (left) and the volatile electricity price set (right)

Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

3.2.5 Increased Benefits of Flexibility Under Low Capital Costs

We hypothesized that the economics of an N-R HES with an electrolyzer with a lower capital cost and reduced efficiency mean that the hybrid system is more likely to switch between electricity and hydrogen products and that flexibility will increase profitability. To test this hypothesis, we replaced the LTE subsystem's projected capital cost and efficiency with $100/kWe equipment cost ($154/kWe total capital) and 60% efficiency (lower heating value basis), as discussed in Section 2.5, and tested the impacts of those parameters both with and without a cost of carbon.

Figure 31 shows the impacts of the reduced capital cost and efficiency on the optimal set of subsystems at various hydrogen prices and electricity price multipliers. At electricity price multipliers greater than 1.4 and hydrogen prices around $3.85/kg, LTE subsystems with reduced capital and efficiency are included in the optimal configuration. LTE subsystems are not included in the scenario with base case capital cost and efficiency. Figure 32 shows the increase in hydrogen production. Comparing the points between the graph on the left and the one on the right shows that a small amount of additional hydrogen is produced in that range.

At a few points, the optimal configuration with the lower cost LTE subsystem includes the wind power plant in addition to the nuclear reactor and thermal power cycle in the standard cost LTE subsystem. Those points are at hydrogen prices of approximately $2.85/kg and electricity price multipliers between 1.35 and 1.5. At those points, LTE uses purchased electricity as well as electricity generated by the nuclear reactor and/or wind plant in the N-R HES for hydrogen production (see Figure 33). At other points nearby and with the lower cost LTE subsystem, the wind power plant is added to complete the N-R HES full configuration.

These results indicate that, in general, LTE with lower capital cost parameters is included at a higher electricity price multiplier and, when the electricity price multiplier is between 1.35 and 1.5, at slightly lower hydrogen prices. This is because lower capital cost LTE has a lower annualized capital cost. In addition, it can use internally generated electricity when the market price for that electricity is $0/MWh (704 hours annually) even though the cost of electricity for electrolysis is higher when electricity prices are greater than $0/MWh.

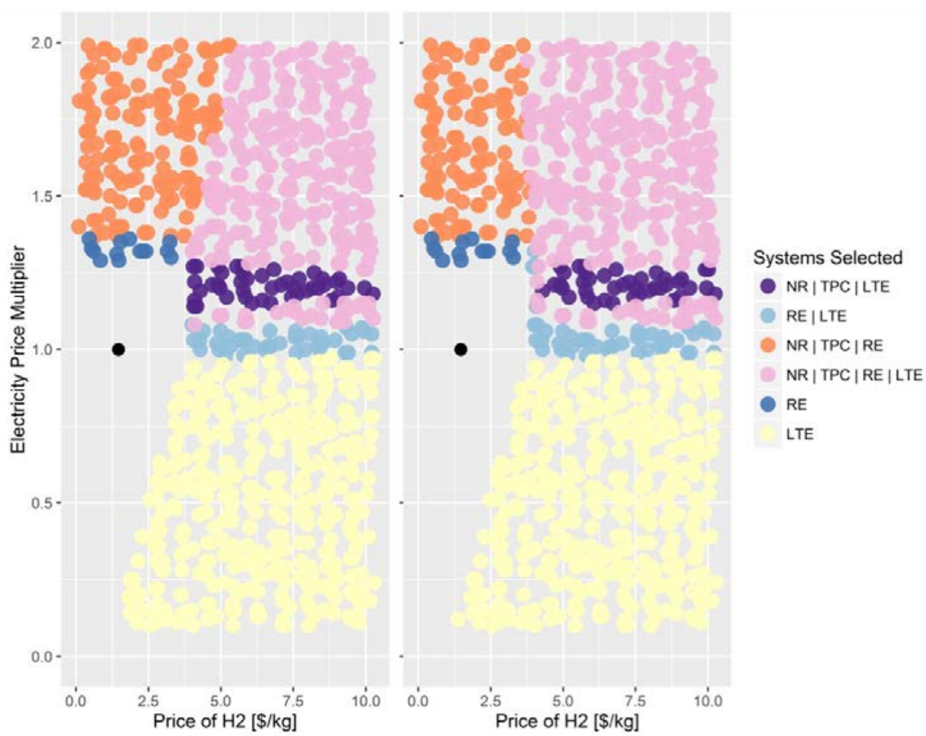

Figure 31. Optimal configurations for the LTE scenario at various hydrogen prices and electricity price multipliers with two different electrolyzer prices and efficiencies

Projected electrolyzer parameters (left); low-cost electrolyzer parameters (right)

$50/kW-yr capacity payments
LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

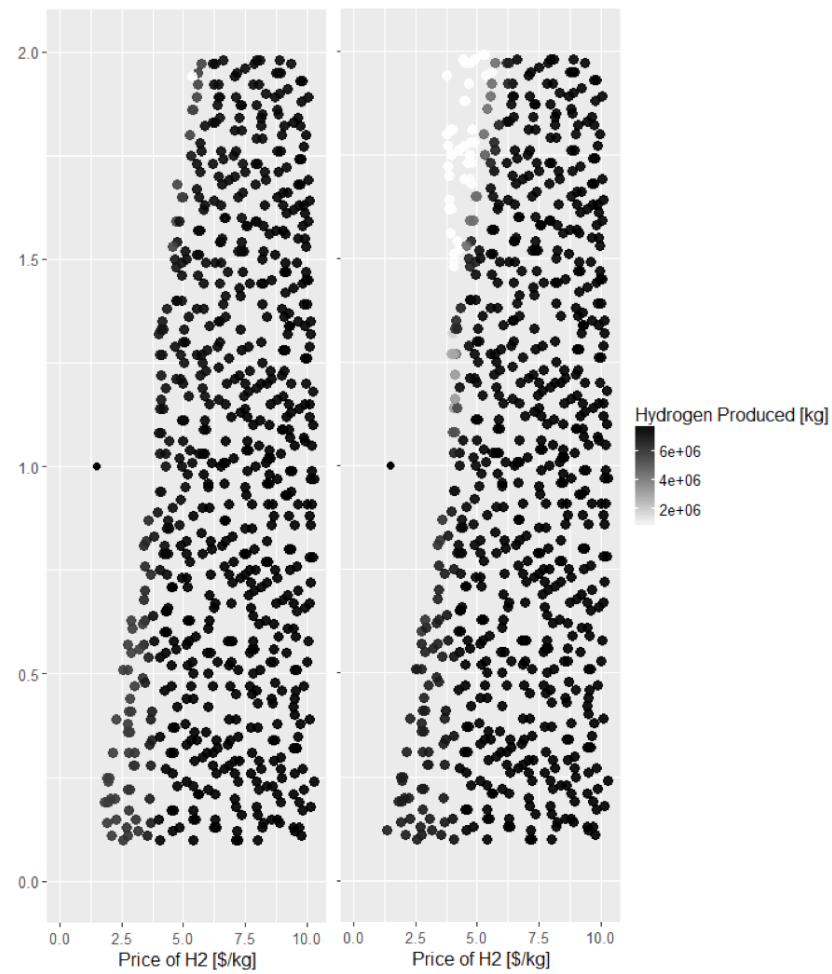

Figure 32. Optimal annual hydrogen generation for the LTE scenario at various hydrogen prices and electricity price multipliers with two different electrolyzer prices and efficiencies

Projected electrolyzer parameters (left); low cost electrolyzer parameters (right)

$50/kW-yr capacity payments. Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

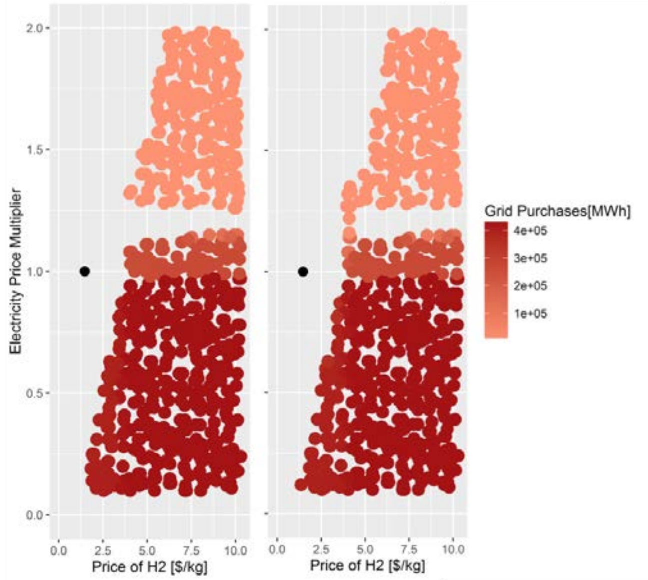

Figure 33. Optimal electricity purchases for the LTE scenario at various hydrogen prices and electricity price multipliers with two different electrolyzer prices and efficiencies

Projected electrolyzer parameters (left); low-cost electrolyzer parameters (right)

$50/kW-yr capacity payments. Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Figure 34 shows the impacts of the reduced capital cost and efficiency on the optimal set of subsystems at various hydrogen prices and electricity price multipliers under a $61/metric ton CO_2e cost of carbon. Like the cases without a cost of carbon, electrolyzers with reduced capital cost and efficiencies only have minor impacts on the optimal configurations. At electricity price multipliers greater than 1.4 and hydrogen prices around $3.85/kg, LTE subsystems with reduced capital costs and efficiencies are included in the optimal configuration where they are not included in the scenario with base case capital cost and efficiency. In addition, several new profitable configurations with hydrogen prices of $3.75/kg and electricity price multipliers between 0.95 and 1.05 are identified, and the range where the optimal configuration includes the nuclear reactor, the thermal power cycle, and LTE—but not the wind power plant—shrinks slightly.

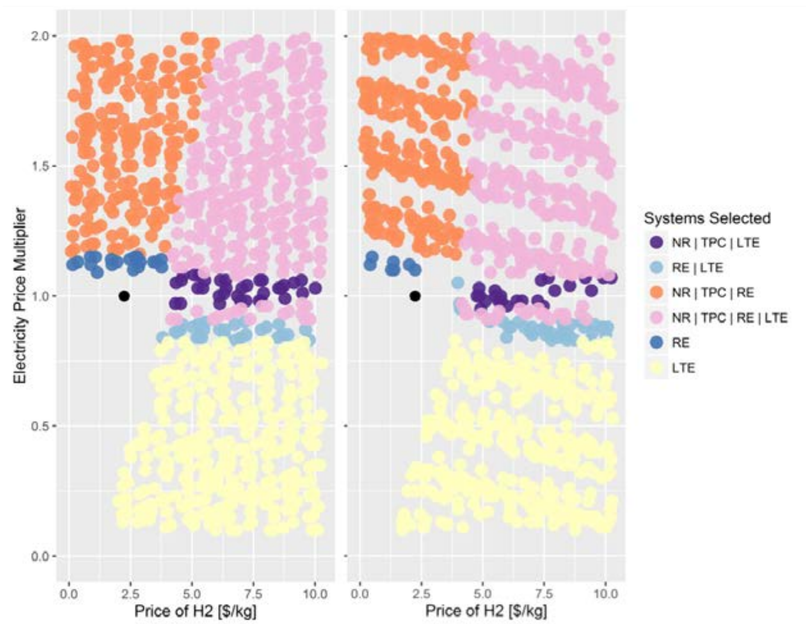

Figure 34. Optimal configurations for the LTE scenario at various hydrogen prices and electricity price multipliers with two different electrolyzer prices and efficiencies with both at a $61/metric ton CO_2e cost of carbon

Projected electrolyzer parameters (left); low-cost electrolyzer parameters without a cost of carbon (right)

$50/kW-yr capacity payments
LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $2.20/kg and 1.0 indicates reference case hydrogen and electricity prices with a $61/metric ton CO_2e cost of carbon.

Figure 35 shows the impacts of the volatile electricity price set on the N-R HES with the low-cost electrolyzer parameters. Both graphs show the optimal system configurations with the low-cost electrolyzer. The one on the left is under the primary electricity price set and matches the graph on the right in Figure 31. As with the base case electrolyzer costs, the results show that more configurations are profitable under the volatile electricity prices than under the primary set of electricity prices, especially when the electricity price multiplier is close to 1.0. The figure shows that the configuration with only low-cost LTE is almost profitable under the volatile electricity price set.

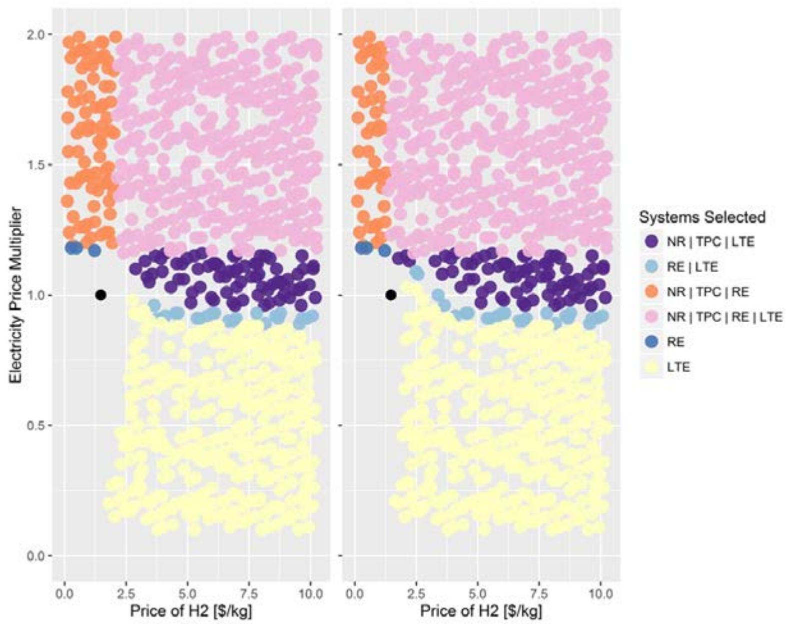

Figure 35. Optimal configurations for the LTE scenario with low-cost electrolyzer under the primary electricity price set (left) and the volatile electricity price set (right)

$50/kW-yr capacity payments

LTE: low temperature electrolysis subsystem
NR: nuclear reactor
RE: renewable electricity generation (wind power plant)
TPC: thermal power cycle
Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

Table 15 compares other financial parameters of the electrolyzer-only configurations with the reference case electrolyzer parameters and the low-cost electrolyzer parameters under both electricity price sets at an electricity price multiplier of 1.0 and hydrogen price of $1.47/kg. Under the primary electricity price set, the electrolyzer does not produce hydrogen because the electricity value (energy and ancillary services) is too high to use electricity to make hydrogen. Under the volatile price set, the electrolyzers optimally produce hydrogen during most of the hours during the year when the electrical energy price is $0/MWh. Like the primary price set, the value of regulation reserve ancillary services sometimes is high enough that the electrolyzer is optimally held in reserve instead of generating hydrogen. In both cases, the NPV under the primary electricity price set is less negative than under the volatile price set because of the value of those ancillary services.

Table 15. Low Temperature Electrolysis Scenario Output Summary at Base Case Conditions for Two Sets of Electrolyzer Parameters Under Both Electricity Price Sets

Electricity Price Set	Primary	Primary	Volatile	Volatile
Electrolyzer Parameters	**Projected**	**Low Cost**	**Projected**	**Low Cost**
Annual Electricity Purchases (GWh)	0	0	136	130
Annual Hydrogen Production (metric ton)	0	0	2,710	2,360
TCI ($million)	$31	$8	$31	$8
NPV at 10% Discount Rate ($million)	-$24	-$6	-$28	-$12
IRR After 25 Years of Operation	N/A *	N/A *	N/A *	N/A *
NPV/TCI Ratio	-0.82	-0.82	-0.90	-1.5

TCI: total capital investment
IRR: internal rate of return

* IRR cannot be calculated for the configuration with LTE only because the cash flow is negative for all years.

These results indicate that the impacts of reduced capital costs and efficiency are similar with or without a cost of carbon. Under the primary electricity price set, LTE with lower capital cost parameters is included in the optimal configuration at a higher electricity price multiplier and, when the electricity price multiplier is above 1.25, at slightly lower hydrogen prices. The reason is that the lower annualized capital cost has a greater impact on profitability than the higher operating costs when electricity prices are greater than $0/MWh. Under the volatile electricity price set, LTE with lower capital cost parameters is included in the optimal configuration at hydrogen prices greater than $1.60/kg and when the electricity price multiplier is above 1.15. The reason is that the lower annualized capital cost has a greater impact on profitability than the higher operating costs when electricity prices are greater than $0/MWh. Under the conditions used for this analysis, the lower capital cost electrolyzer's reduced efficiency counteracts the reduced capital cost. Therefore, when the electricity price is $0/MWh for more than the 704 hr/yr in the primary electricity price set, the impact of the capital cost reduction on profitability is more pronounced. The combination of reduced electrolyzer costs and volatile electricity prices results in a configuration that is nearly profitable and provides flexibility that supports the grid. Higher capacity payments or including a cost of carbon may provide conditions where configurations with the low cost electrolyzer are profitable. Investigating those options is outside the scope of this analysis.

4 Conclusions

We analyzed the financial performances of two N-R HES scenarios. Each N-R HES has the potential to generate electricity for the grid and produce hydrogen. To perform the analysis, we modified the Texas N-R HES in Ruth et al. (2016)[77] by removing its industrial process and adding an electrolyzer subsystem. The HTE scenario includes an HTE subsystem that utilizes heat from the nuclear reactor and electricity from the thermal power cycle, the wind power plant, and/or the grid. Two LTE scenarios include an LTE subsystem that utilizes only electricity. One involves projected electrolyzer costs and performance and the second involves lower cost electrolyzers that have a reduced efficiency. Electricity for electrolysis could be from thermal power cycle, the wind power plant, and/or the grid.

We tested four hypotheses on each of the first two scenarios:

1. The N-R HES configurations analyzed have the potential to be profitable to investors and are likely to be more profitable than uncoupled configurations.
2. Hydrogen generated by an N-R HES can economically reduce greenhouse gas (GHG) emissions from hydrogen production compared to steam methane reforming. We also analyze the impact of a cost of carbon on the relative economics.
3. N-R HESs can support resource adequacy for the electricity grid while maximizing production of an alternative product (hydrogen) if market structures incentivize that option.
4. N-R HESs will be more profitable than uncoupled configurations because they can produce electricity when its price is high and hydrogen when the price of electricity is low.

We also tested a fifth hypothesis using the two LTE scenarios:

5. If research and development can lead to LTE with a lower capital cost, even if the efficiency is compromized, then N-R HESs with LTE will be more profitable and more likely to switch between electricity and hydrogen products.

For the base case analyses, the financial assumptions include 100% equity, a 10% nominal discount rate, a 3% inflation rate, and startup in 2035. Capital and operating cost estimates come from other published analyses as described in the body of this report. Because the prices of electricity and the hydrogen product are uncertain, we report sensitivities to those prices. In addition, electricity price estimates in this analysis are based on static mixes of electricity generators and do not include the impacts of decisions that are made for future years, so our analysis may undervalue opportunities in the evolving energy system.

Our analysis partially supports hypothesis #1. Under reference case prices (electricity multiplier of 1.0, hydrogen price of $1.47/kg), none of the configurations we considered for all three scenarios are profitable. The primary reason for this outcome is that the reference case hydrogen and electricity prices are low compared to the N-R HES's projected production costs - too low to meet the capital and operating costs. However, we identified opportunities where both LTE and HTE N-R HESs, may be profitable when electricity prices are high, natural gas prices are high, or a cost of carbon is included. One key reason that no base case configurations meet the profitability requirement is that the reference case hydrogen and electricity prices are low when compared to the N-R HES's projected production costs. The reference case hydrogen price is set by the minimum price for steam reforming of natural gas to produce hydrogen. The primary driver of the \$1.47/kg H_2 reference hydrogen case price is the price of natural gas, which is \$6.98/mmBtu based on the 2015 AEO projection for 2035.[78]

The primary reference case electricity price set is based on production cost modeling of a generation mix with 21% of the annual generation from wind power and 20% from PV. One key assumption is that most of the remaining 59% of generators are modern natural gas turbines and NGCC generators. Those modern generators are flexible with high ramp rates, short minimum up and down times, and low restart costs, so the resulting electricity prices are not as volatile as they are likely to be with less flexible generators. A second key assumption in the primary electricity price set is that the grid is not transmission constrained (i.e., there is sufficient transmission available).

We also analyzed the N-R HES performance under a volatile electricity price set that is based on production cost modeling of a generation mix with 37% of the annual generation from solar generators and 8.6% from wind generators and some transmission constraints. That electricity price set has more hours with electricity prices of \$0/MWh than the standard electricity price set. The volatile price set also has more hours with higher prices than the standard electricity price set and higher prices during those hours. Therefore, the volatile electricity price set has fewer hours with electricity prices between \$50/MWh and \$60/MWh. The volatile price set resulted in many more combinations of electricity price multipliers and hydrogen prices where the optimal N-R HES is identified as profitable; however, the case with the reference hydrogen price of \$1.47/kg H_2 and electricity price multiplier of 1.0 is not projected to be profitable for either the HTE or LTE N-R HES. Therefore, reduced generation flexibility or constrained grid transmission increases the likelihood that these N-R HESs will be profitable.

Another key reason none of the reference case configurations meet the cost of equity is that the electrolysis capital cost and efficiency projections that we used are less aggressive than the R&D targets. We used the \$400/kWe (2012\$) projected purchase price for low-temperature electrolyzers and projected efficiency of 66%. The DOE Fuel Cell Technologies Office set more aggressive targets for low-temperature PEM electrolysis in its Multi-Year Research, Development, and Demonstration Plan.[79] In that plan, the electrolyzer cost target is \$242/kW (in 2007\$—equivalent to \$269/kW in 2012\$) and the efficiency target is 75% (a lower heating value basis). For the other parameters in this report, we used projected values—not targets—so, to be consistent, we used the projected electrolyzer costs and performance in this analysis.

Our analysis findings indicate that high carbon costs or resource limitations are required to support hypothesis #2. None of the HTE or LTE (standard capital cost) configurations were profitable at reference case conditions, even when a cost of carbon of \$61/metric ton CO_2e (the Interagency Working Group social cost of carbon with a 3% discount rate) was added to the price of electricity and to hydrogen generated from natural gas. A higher cost of carbon would be needed to make the configurations profitable at reference case prices.

This conclusion stands even though the reference case price for hydrogen is increased from \$1.47/kg H_2 to \$2.20/kg H_2 to account for the cost for carbon dioxide emitted in the steam methane reforming process. None of the HTE or LTE (standard capital cost) N-R HES configurations tested under the primary electricity price set can sell hydrogen at that price while meeting the required 10% nominal discount rate unless the electricity price multiplier is greater than 1.05.

Other policy and societal drivers could potentially increase that required hydrogen price to a point where the N-R HES configurations analyzed here would be profitable. Examples of such drivers could include a societal cap on natural gas use, a clean hydrogen standard, or a limitation on the use of natural gas production technologies, such as fracking, that would natural gas supply. Under one or more of those drivers, the N-R HESs analyzed here may become profitable and thus contribute to reductions in GHG emissions.

Our analysis results do not support hypothesis #3. None of the HTE or LTE (projected capital cost) configurations are profitable at reference case conditions, even at capacity payments up to $150/kW-yr. Increased capacity payments reduce the hydrogen prices and electricity price multipliers necessary for the N-R HESs to be profitable and thus to support grid resource adequacy; however, under the primary set of electricity prices, capacity payments higher than $150/kW-yr are necessary for the N-R HESs analyzed to be profitable at reference case prices. We did not test the impact of capacity payments under a more volatile set of electricity prices.

Our analysis findings partially support hypothesis #4. Under volatile electricity price conditions, N-R HESs have a higher NPV than uncoupled configurations because they can produce electricity when the price of electricity is high and hydrogen when the price is low. The primary electricity price set does not have enough volatility for either the HTE or LTE (projected capital cost) configuration to produce hydrogen optimally during any hours of the year at reference case prices. The volatile electricity price set has enough volatility that the LTE N-R HES (projected capital cost) configuration with the nuclear reactor, thermal power cycle, and LTE optimally produces 3,149 metric tons of hydrogen annually, although the NPV of that configuration is still more negative than the configuration only the nuclear reactor and thermal power cycle. Likewise, the full HTE N-R HES configuration optimally produces 4,719 metric tons of hydrogen annually, but its NPV is still more negative than the configuration with only the nuclear reactor and thermal power cycle. Hence, under volatile prices, flexibility of configurations that can produce both hydrogen and other products is valuable but not valuable enough to overcome the increased capital cost.

Our analysis supports hypothesis #5. Under the primary electricity price set and at the base hydrogen price and electricity price multiplier, an N-R HES with an electrolyzer with a lower capital cost and reduced efficiency is not profitable and is unlikely to switch between electricity and hydrogen products. However, under the volatile electricity price set, an N-R HES with an electrolyzer with a lower capital cost and reduced efficiency is profitable at lower hydrogen prices and electricity price multipliers. The benefits of flexibility are realized because of the reduced capital cost and greater number of hours with either very low or very high electricity prices.

To be profitable, the HTE and LTE N-R HES configurations that produce hydrogen examined require higher electricity prices, more electricity price volatility, higher natural gas prices, or higher capacity payments than the reference case values of these parameters considered in this analysis. Electricity prices could be higher if generation options are more limited than considered in this analysis. Natural gas prices could be higher if gas supply is more constrained or greater carbon emissions penalties exist than considered in this analysis. In addition, these N-R HESs show more combinations of electricity price multipliers and hydrogen prices with profitable configurations under the volatile electricity price set than under the primary electricity price set. Electricity prices could be more volatile if the grid is transmission-constrained or if the mix of generators on the grid is less flexible than assumed.

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