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Light Water Reactor Sustainability Program

Guidance on Near-Term Hydrogen Production using Nuclear Power

June 2024
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Guidance on Near-Term Hydrogen Production using Nuclear Power

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EXECUTIVE SUMMARY

The Department of Energy's Light Water Reactor Sustainability (LWRS) program at the Idaho National Laboratory (INL) has established a pathway to research flexible power operations for existing U.S. nuclear reactors to improve plant economics while accommodating increasing penetration of variable renewable wind and solar generation on the bulk power grid. The LWRS Flexible Plant Operation and Generation (FPOG) pathway has coordinated several research efforts to assess nuclear power plant (NPP) modifications that enable the use of large-scale thermal energy (steam) and electricity to support the production of alternative clean energy products, which can compete economically with current nuclear operations. A leading clean energy product is hydrogen, which is the subject of this report.

A summary of the pathway work completed for production hydrogen with nuclear power is presented here. Due to its high efficiency and potentially low hydrogen production cost, this report specifically focuses on high-temperature steam electrolysis (HTSE) for hydrogen production. Guidance herein provides immediate support to the early movers of hydrogen production in time for decisions to include HTSE in Hydrogen Hub projects or any other near-term project looking to take advantage of the U.S. Inflation Reduction Act - Clean Hydrogen Production Tax Credit (Section 45V). This body of work is systematically presented to provide guidance that can be used to develop an implementation strategic plan (ISP) for plant-specific/project-specific cases. The ISP ultimately informs the utility development of the conceptual plant design.

The development of an ISP is predicated on ensuring that NPP safety is maintained, and that the economic viability of an integrated system can be demonstrated to achieve the project-specific economic requirements. The LWRS program has completed a set of evaluations that provide guidance for subsequent project-specific analysis to assess modifications to the NPP in consideration of the following aspects:

- Thermal power (steam) extraction from the plant steam turbine system to provide heat for the High-Temperature Electrolysis Facility (HTEF) and assessment of the impacts on steam cycle equipment
- Electrical power to supply the hydrogen production system (high-temperature electrolyzer), compression systems, and balance of plant equipment
- Hydrogen production control systems and NPP control room modifications
- Siting of the HTEF in consideration of the addition of potential hazards to the NPP systems, structures, and components (SCCs) important to safety and plant operation
- Impacts to the plant probabilistic risk assessment (PRA)
- Impacts to the plant licensing basis, including consideration of 10CFR50.59.

A broad set of economic analyses and hydrogen market assessments have been assembled in parallel with the engineering and NPP modification and HTEF integration efforts. A progressive approach is used to scope out market potential, complete a financial evaluation of the economic potential of capital investments in the project, and ensure the project is "future-proof" versus competition, regulations, and grid market transitions. A project-specific ISP and associated economic evaluations should consider the following:

- Assessment of the resource potential using the Prospector Tool that identifies hydrogen markets located in proximity to the NPP along with infrastructure, such as power transmissions lines; natural gas pipeline corridors; highway, rail or estuary commerce routes; water resources; population centers; protected or environmentally sensitive lands and airsheds.
- Technology potential that addresses the integration and control of the hydrogen plant in accordance with the project purpose. Flexible, or hybrid, plant operations, may be evaluated to establish the project functional and operating requirements, which in turn determine the best hydrogen production and storage requirements, as well as operating concepts based on project ownership and control. Technology potential includes a detailed plant design to establish the capital and operating costs of the plant. The fidelity level of the plant design corresponds to the stage of financial commitment to the project.
- Economic potential based on detailed sensitivity analysis of power rates, hydrogen pricing, investment options, and discount rates. This step is generally iterative with technology potential given specific options of hydrogen storage and end uses.
- Market potential based on analysis of competition with the next best option for producing hydrogen. This inevitably requires a multi-market, multi-commodity assessment to ensure project success and profitability.

A general process is outlined for the development of a project-specific ISP and is documented herein. A summary of the supporting technical reports is provided. The LWRS program remains engaged in further analysis to broaden the applicability of the processes and guidance developed thus far.

ACKNOWLEDGEMENTS

The authors acknowledge Nikki Peterson, Rachael Hansen and David Livingston for their diligent editorial review of the document.

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FIGURES

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ACRONYMS

BESS	Battery Energy Storage System
BOP	balance of plant
BWR	boiling water reactor
DBA	Design Bases Accident
DOE	Department of Energy
EI	Event Initiator
ES	extraction steam
ET	Event Tree
ETES	Electro-Thermal Energy Storage
FMEA	Failure Modes and Effects Analysis
FPOG	Flexible Power Operation and Generation
FWH	feedwater heater
GPWR	Generic Pressurized Water Reactor
GSU	generator step-up (transformer)
HELB	high energy line break
HES	heat extraction system
HITL	human-in-the-loop
HPT	high-pressure turbine
HSI	Human System Interface
HSS	High-Temperature Steam Supply
HTGR	high-temperature gas-cooled reactor
HTSE	high-temperature steam electrolysis
IES	integrated energy system
INL	Idaho National Laboratory
ISP	Implementation Strategic Plan
ITC	Investment Tax Credit
LAR	Licensing Amendment Request
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
LERF	Large Early Release Frequency
LFP	Lithium iron phosphate
LOOP	Loss of Offsite Power
LPT	low-pressure turbine

LWR	light water reactor
LWRS	Light Water Reactor Sustainability
MSDT	moisture separator drain tank
MSR	moisture separator reheater
MTC	moderator temperature coefficient
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
NMC	Nickel molybdenum cobalt
NPDES	National Pollutant Discharge Elimination System
NPP	nuclear power plant
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
O&M	operations and maintenance
OEM	original equipment manufacturer
P&ID	process and instrumentation diagram
PEPSE	Performance Evaluation of Power System Efficiencies
PRA	probabilistic risk assessment
PTC	Production Tax Credit
PV	photovoltaic
PWR	Pressurized Water Reactor
rSOEC	Reversible Solid Oxide Cell
RCS	Reactor Coolant System
RG	(NRC) Regulatory Guide
SG	steam generator
SH-TES	Liquid-Based Sensible Heat Thermal Energy Storage
SME	subject matter expert
SOEC	Solid Oxide Electrolysis Cell
SOFC	Solid Oxide Fuel Cell
SSC	systems, structures, and components
TDFP	turbine driven feed pump
TEA	techno-economic analysis
TNT	trinitrotoluene
TPD	thermal power dispatch
TPE	thermal power extraction
UFSAR	Updated Final Safety Analysis Report

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Guidance on Near-Term Hydrogen Production using Nuclear Power

1. INTRODUCTION

1.1 Background

This document presents the outcomes of research and testing conducted under the U.S. Department of Energy (DOE) Light Water Reactor Sustainability (LWRS) program to connect nuclear power plants (NPPs) to large, commercial hydrogen production electrolysis plants. The intent is to provide NPP owners, electrical power utilities, hydrogen gas suppliers, and users introduction and access to (1) computation tools that evaluate the business case and investment decisions for producing hydrogen based on individual plant and location-specific conditions, (2) preconceptual architecture/engineering design documents that can be used to guide plant-specific integration with a close-coupled hydrogen plant, (3) operating concepts that allow the nuclear plants to dispatch electricity and steam to a water-splitting electrolysis plants to produce hydrogen, (4) generic safety hazards and risk assessments that are pertinent to evaluating license requirements, and (5) regulatory perspectives and approaches that need to be taken into consideration.

National security and quality of living ultimately require adequate secure energy and environmental sustainability. Nuclear power generation has been proven to be an essential component of the U.S. electric power system, providing steady carbon-free power generation with unparalleled reliability and annual capacity factors exceeding 92%. Sustained nuclear power generation is critical to maintaining energy security. Domestic nuclear power generation also plays a key role in transitioning the electric power grid to meeting climate goals and decarbonizing other energy sectors, particularly transportation.

Despite the significant benefits of nuclear power, the U.S. nuclear industry faces circumstantial economic challenges. Market conditions have forced reactors into early retirement while others have engaged in flexible power dispatch to accommodate subsidized variable renewal generation and transmission constraints, which can lead to sustained periods of low and even negative power pricing.

Flexible plant operation and generation (FPOG) allows NPPs the ability to dispatch power to the grid or deliver steam and electricity to an industrial user (Figure 1-1). Thus, nuclear power can be used to produce nonelectric products during periods of excess power generation capacity when these plants are not able to clear the day-ahead electricity market. This practice preserves the contribution of nuclear energy to grid stability and reduces economic losses associated with negatively priced electricity sales. It provides an offtake for energy produced by a nuclear power generating station when the price offered for committing electricity to the grid is lower than the cost of electricity production. Secondary nuclear power recipients benefit by purchasing electrical power, steam, or thermal energy directly from NPPs at costs that can be lower than those paid by electricity transmission-customers or electricity distribution-customers.

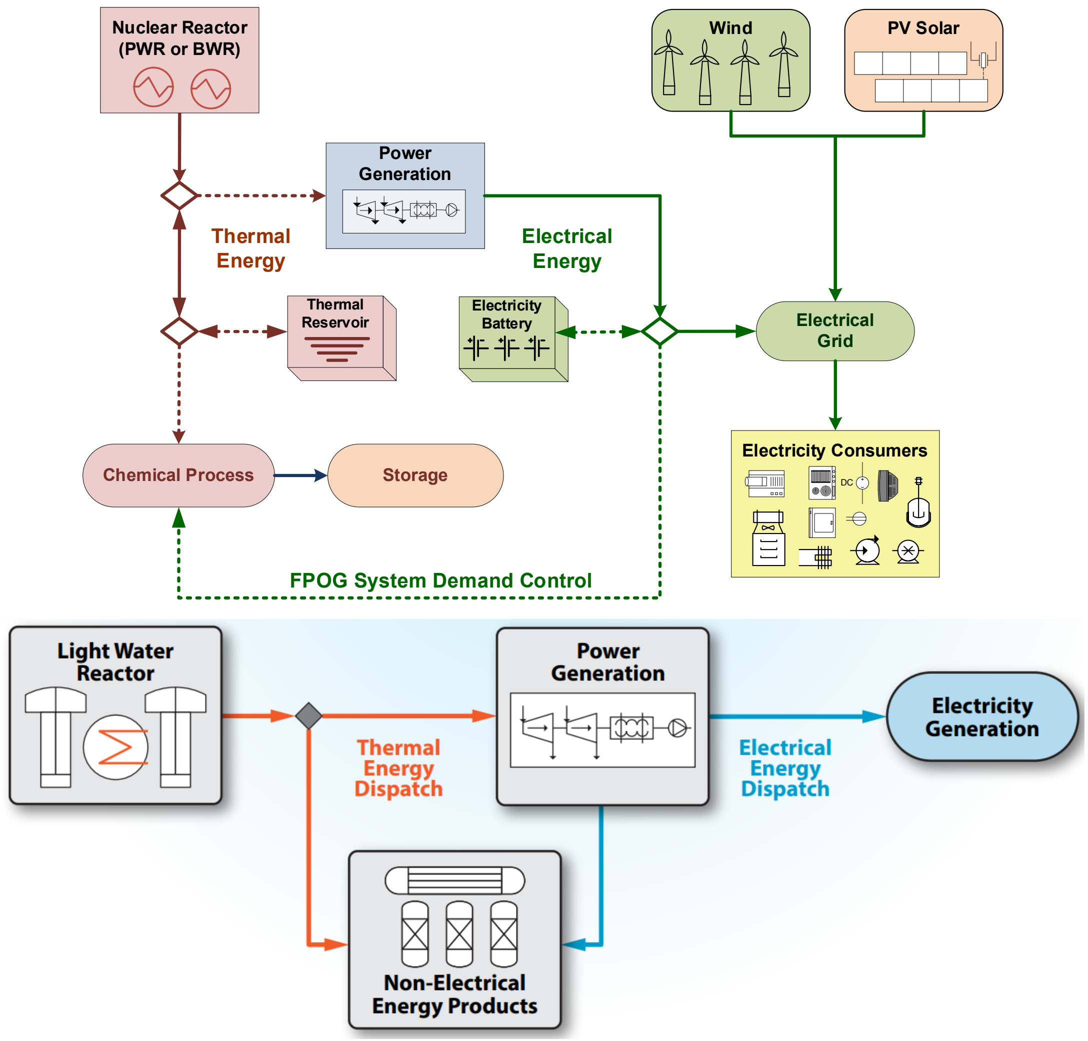

Figure 1-1. FPOG concept for NPPs.

1.2 Flexible Hydrogen Generation

For the past 5 years, FPOG research has mainly focused on hydrogen production. Water-splitting electrolysis includes several technologies that produce hydrogen (H_2), oxygen (O_2), or both. Conventional low temperature electrolysis (LTE) uses electricity with alkaline cells or proton exchange membranes (PEMs) to split liquid water molecules into hydrogen and oxygen. Advanced, high-temperature steam electrolysis (HTSE) uses electricity and heat with solid oxide electrolysis cells (SOECs) to split steam molecules. The use of steam and heat in HTSE reduces the required electric power consumption to increase the efficiency of HTSE compared to LTE. Nuclear plants are well-suited to produce the steam and electricity needed by HTSE (Figure 1-2).

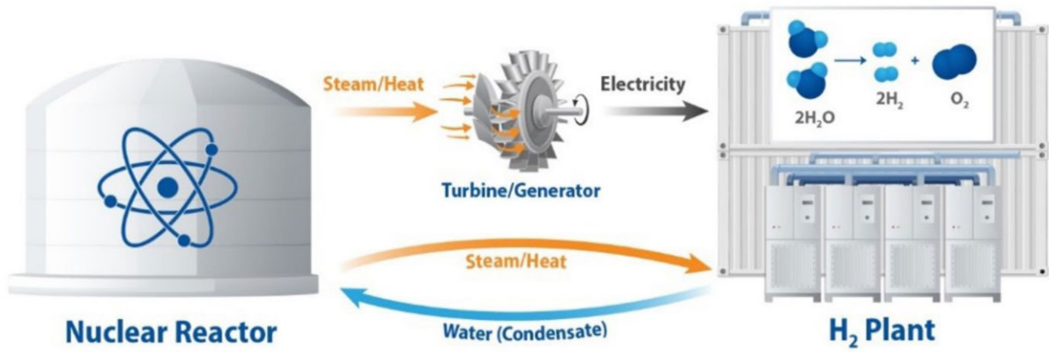

Figure 1-2. Nuclear power HTSE.

With connection to either a low or a high-temperature electrolysis (HTE) hydrogen plant, it is possible to flexibly dispatch power to the grid by merely throttling the electrolysis plant and shifting electrical power to the grid from the nuclear plant transmission switchyard. Under this mode of operation, the coupled nuclear and hydrogen plants can function as reserve capacity by the regional reliability office or grid balancing authority.

In order to tightly couple NPPs with large-scale hydrogen production plants, several issues must be addressed to ensure that the NPP will operate within the approved design and licensing bases. Modifications to the plant and operation of the coupled system must address technological, regulatory, economic, and environmental constraints.

Hydrogen has historically been considered as an alternative energy carrier. It is a chemical staple that is used to produce ammonia-based fertilizers. Ammonia (NH_3) is also used to refine and hydrocrack/hydrotreat petroleum crude to produce gasoline, diesel, and heating oil fuels (fundamentally as -CH2- and -OH- molecular building units).

Expansion of the hydrogen market to support fuel-cell-powered cars and trucks, the production of chemicals, such as methanol, steel, biofuels and synthetic fuels, and the use of hydrogen as a substitute fuel for natural gas for power generation and process heating was revitalized around 2016 under a DOE Big Idea referred to as H2@Scale (hydrogen at scale).[a] A graphic was developed to illustrate clean hydrogen production and use for low-emissions power generation and across many industries for heating and the chemical processing (Figure 1-3).

The foundation for this initiative is rooted in the Energy Policy Act of 2005 (EPACT), Title VIII-Hydrogen, with the following goal:

"The goal of the program shall be to demonstrate and commercialize the use of hydrogen for transportation (in light duty vehicles and heavy duty vehicles), utility, industrial, commercial, and residential application)."

a DOE Hydrogen and Fuel Cell Technologies Office, https://www.energy.gov/eere/fuelcells/h2scale.

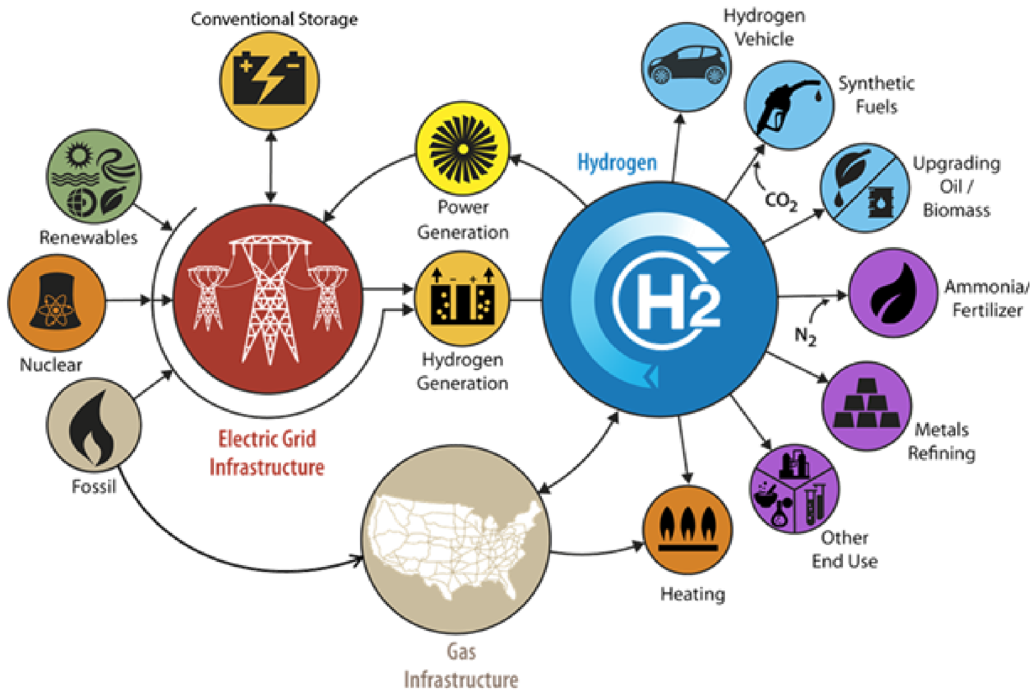

Figure 1-3. Visualization of DOE concept for H2@Scale.

Following a lull from around 2010 to 2018 in hydrogen-related research and development activities authorized by EPACT 2005, DOE and industry research surged with renewed appropriations by Congress under the Bipartisan Infrastructure Law (also known as the Infrastructure Investment and Jobs Act) signed into law November 2021 and under the Inflation Reduction Act (IRA) signed into law August 2022. Together, these bills commit a large investment in infrastructure development projects and manufacturing while providing large tax incentives for investments and production of clean energy products. The major goal is to build technologies and energy systems that support the American economy, increase energy security, and reduce atmospheric climate impacts associated with greenhouse gases and other primary air pollutants that have long been associated with combustion of fossil fuels.

1.3 National Clean Hydrogen Strategy Roadmap

With over $500 billion directed to clean energy project demonstrations, a new DOE office—the Office for Clean Energy Demonstrations (OCED)—was stood up. These funds included $8 billion of DOE cost-shared funding to establish Regional Clean Hydrogen Hubs and $1 billion to support commercial manufacturing of electrolysis technologies. Additional annual Congressional funding supports development and testing of hydrogen production, supply, storage, and use technologies. This research is orchestrated by a DOE U.S. National Clean Hydrogen Strategy and Roadmap.[b] The Roadmap provides an overview of core technology areas, challenges, and research and development (R&D) thrusts that DOE is pursuing to address these challenges through an integrated DOE program cross-cutting plan.

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b U.S. Department of Energy. August 2023. "Department of Energy Hydrogen Program Plan." U.S. National Clean Hydrogen Strategy and Roadmap | Hydrogen Program (energy.gov).

In 2023, OCED separately issued national strategy guidance in documents, which was termed Pathways to Commercial Liftoff.[c] The Liftoff document for clean hydrogen presents the following goals:

Near-term expansion (2023–2026): Accelerated by the production tax credits, clean hydrogen replaces today's carbon-intensive hydrogen, primarily in industrials/chemicals use cases including ammonia production and oil refining. This shift will primarily occur at co-located production/demand sites or in industrial clusters with pre-existing hydrogen infrastructure. In parallel, first-of-a-kind projects are expected to break ground, driven by $8B in DOE funding for Regional Clean Hydrogen Hubs that will advance new networks of shared hydrogen infrastructure.

Industrial scaling (~2027–2034): Hydrogen production costs will continue to fall, driven by economies of scale and R&D. During this period, privately funded hydrogen infrastructure projects will come online. These investments, including the build-out of midstream distribution and storage networks, will connect a greater number of producers and off-takers, reducing delivered cost and driving clean hydrogen adoption in new sectors (e.g., fuel-cell-based transport). At the same time, hydrogen combustion or fuel cells for power could be needed to achieve the [Presidential] Administration's goal of 100% clean power by 2035. There are a wide range of forecasts denoting hydrogen's role in the power sector, whether for high-capacity firm, lower capacity factor power, or seasonal energy storage.

Long-term growth (~2035+): A self-sustaining commercial market post-production tax credits expiration will be driven by falling delivered costs due to:

- Availability of low-cost, clean electricity (for electrolysis)
- Equipment cost declines
- Reliable and at-scale hydrogen storage
- High utilization of distribution infrastructure, including dedicated pipelines that move hydrogen from low-cost production regions to demand clusters.

The Congressional funding opportunities provide incentive for NPPs to evaluate the opportunity to switch to hydrogen production, either with part-load or full load commitment to hydrogen production.

2. NUCLEAR HYDROGEN PRODUCTION IMPLEMENTATION STRATEGY PLANNING

2.1 Objectives

The objective of this report is to consolidate and disseminate the nuclear plant hydrogen production R&D activities completed under the LWRS program. The goal is to provide immediate support to the early movers of hydrogen production with HTSE, in time for decisions to include HTSE in Hydrogen Hub projects, or any other near-term project looking to take advantage of the U.S. IRA - Clean Hydrogen Production Tax Credit (Section 45V). A list of the milestone reports that are available to the public is provided in Appendix A. This body of work is systematically presented to provide guidance that can be used to develop an implementation strategic plan (ISP) for plant-specific/project-specific cases.

c DOE Office of Clean Energy Demonstrations, "OCED Clean Hydrogen Liftoff Report" https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf

The general ISP process is presented in Figure 2-1. The ISP ultimately informs the utility development of the conceptual plant design. The process starts with a market assessment based on nuclear plant location and the potential of surrounding hydrogen markets. The potential for new projects is often evaluated using the process illustrated in Figure 2-2. This progressive approach is used to scope out market potential, complete a financial evaluation of the economic potential of capital investments in the project, and ensure the project is "future-proof" versus competition, regulations, and grid market transitions. The potential for new projects can be divided into the following four categories:

- Resource potential includes necessary resources for hydrogen production and can be supported with a tool developed by the LWRS program that is currently referred to as the Prospector Tool. This tool identifies hydrogen markets located in proximity to the NPP along with infrastructure, such as power transmission lines, natural gas pipeline corridors, highway, rail or estuary commerce routes, water resources, population centers, protected or environmentally sensitive lands and airsheds, etc.
- Technology potential addresses the integration and control of the hydrogen plant in accordance with the project purpose. Flexible or hybrid plant operations may be evaluated to establish the project functional and operating requirements, which in turn determine the best hydrogen production and storage requirements, as well as operating concepts based on project ownership and control. Technology potential includes a detailed plant design to establish the capital and operating costs of the plant. The level of fidelity of the plant design corresponds to the stage of financial commitment to the project.
- Economic potential requires a detailed sensitivity analysis of power rates, hydrogen pricing, investment options, and discount rates. This step is generally iterative with technology potential given specific options of hydrogen storage and end uses.
- Market potential requires analysis of competition with the next best option for producing hydrogen. This inevitably requires a multi-market, multi-commodity assessment to ensure project success and to maximize profitability.

Utility company strategy planners need no reminder of the complexity involved in making investment decisions with market and regulatory uncertainties. With respect to hydrogen production as a business case option, the tools and processes developed by the LWRS program can help alleviate many of the uncertainties by considering the technical design of the hydrogen plant and integration systems, understanding potential operating scenarios, establishing regulatory path certainty, and ensuring market competitiveness.

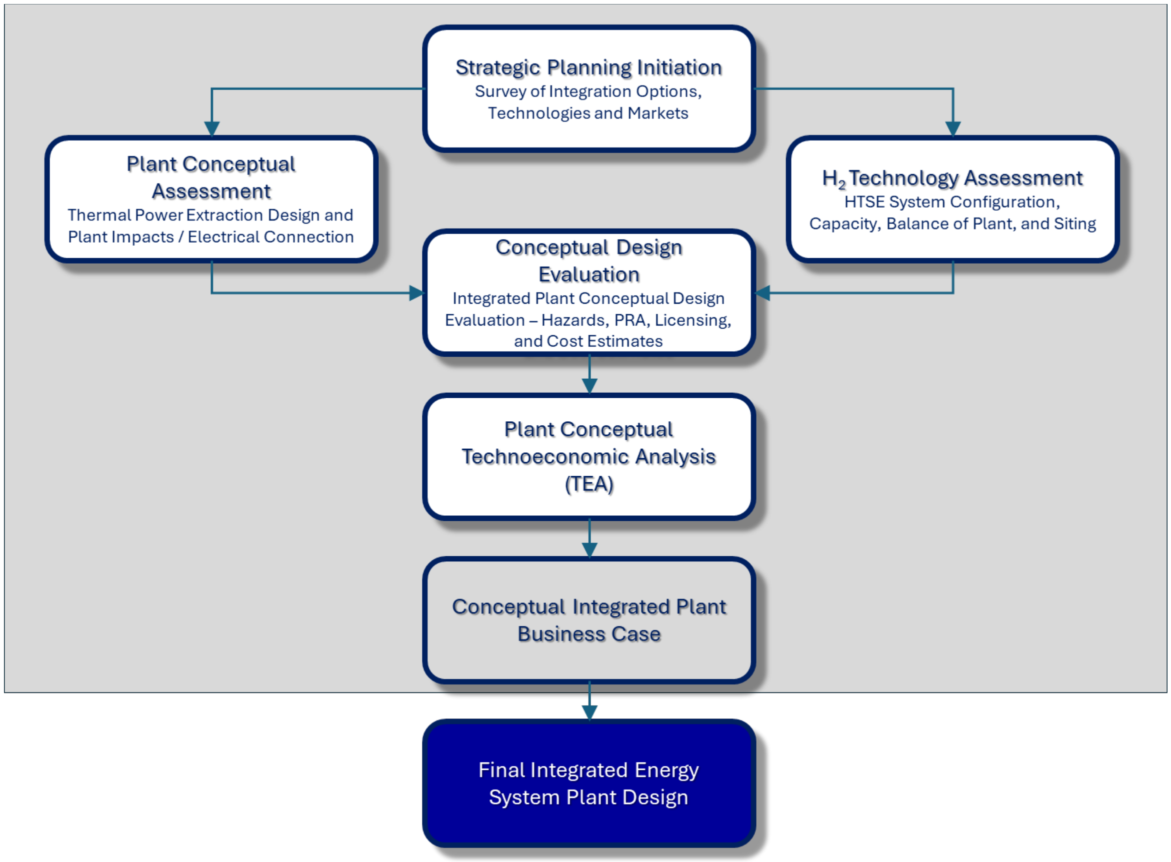

Figure 2-1. Implementation Strategic Plan (ISP) process summary (in the shaded region).

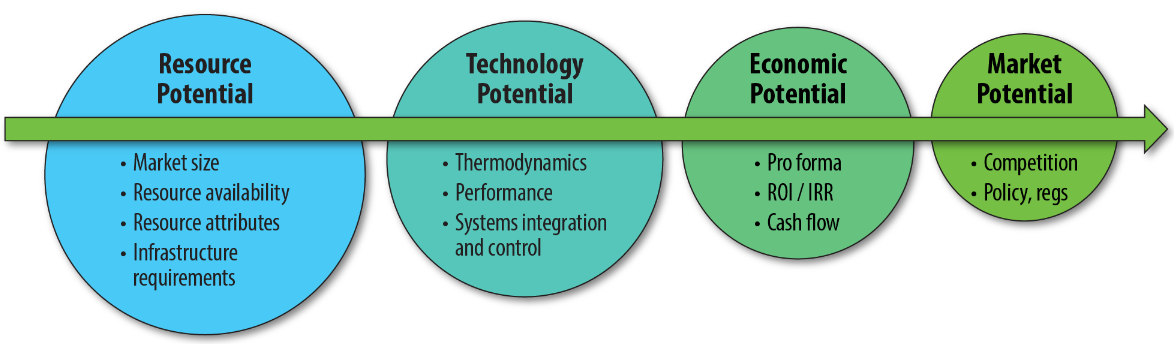

Figure 2-2. Four considerations for evaluating the business case for producing hydrogen.

2.2 Applicability

The ISP is generally [1] applicable to all U.S. LWRs considering integration of HTSE for hydrogen production. The analysis for thermal power (steam) extraction from a PWR secondary system and the associated impacts on the secondary system components have been completed for a reference PWR design. Since the designs of U.S. PWR plant secondary systems are functionally similar, a heat balance analysis for a reference PWR design is expected to provide insight into the impacts on major secondary system components for thermal extraction on a generic basis. The reference plant modeled is a

Westinghouse 4-Loop PWR. Similar efforts are presently underway for an assessment of the impacts on steam cycle components and total plant performance resulting from thermal extraction from the main steam line of a boiling water reactor (BWR). Assessment of regulatory (licensing) impacts, risk evaluation, and operations is also considered generically applicable to all U.S. PWR and BWR plants with plant-specific requirements to be defined in subsequent site and unit-specific analyses.

This guidance is based on a summary of comprehensive analyses completed to establish preconceptual design for thermal power extraction, digital control systems modifications, safety analyses, operating options and approaches, regulatory guidance, probabilistic risk, and siting guidance.

The FPOG program has also completed additional analyses to assess the potential for extracting significantly greater amounts of thermal power for other processes that could use up to 70% of the rated nuclear plant output [2]. The plant impacts associated with these larger scale modifications are informed by the results of these efforts but require substantial plant-specific assessment and are outside of this ISP development, which is based on a 500 MWe integrated HTSE design.

2.3 Summary of Running Research and Development Completed

A summary of select studies and products is tabulated in Appendix A. These documents are presented in more specific detail in the following sections to support the development of a project-specific hydrogen ISP. Other reports are available on the LWRS website under FPOG (https://lwrs.inl.gov/SitePages/Research%20Areas.aspx). The documents describe progress made by the LWRS program in the following areas:

- Technical and economic assessments based on the location-specific projected power generation capacity expansion modeling
- HTSE commercial prototype module testing for confirmation of performance, durability, and operability relative to ramping up and ramping down hydrogen production to enable nuclear plants to participate in reserve capacity markets
- A computation framework for optimization of resources and economics (referred to as FORCE) based on detailed physical models of all systems in the integrated nuclear hydrogen plant with economic proforma algorithms and optimization equations to support the design of the system optimized for dynamic operation to maximize the return on investment
- A simplified project profitability and sensitivity tool based on an Excel spreadsheet calculator, which is useful to scope the economic feasibility during the planning of a project, relative to the hydrogen plant size, online capacity, financial parameters, capital costs, and energy costs
- Detailed conceptual hydrogen plant designs completed by a contracted architectural/engineering firm for a generic, modular HTSE plant that is fully integrated thermally and electrically with a generic NPP and completed for hydrogen plant sizes with electrolysis modules totaling capacities of 100 $MW_{e\text{-}DC}$, 500 $MW_{e\text{-}DC}$, and 1,000 $MW_{e\text{-}DC}$, where the subscript DC refers to the plant direct-current (DC) power rating
- Development and demonstration of full-scope nuclear plant/hydrogen plant simulators for the development and testing of enabling control concepts
- Analysis of the safety hazards associated with hydrogen production near the nuclear plant, including potential detonation of hydrogen/air mixtures at vulnerable positions in the hydrogen plant
- Preliminary probabilistic risk assessment (PRA) using SAPHIRE (Systems Analysis Programs for Hands-on Integrated Reliability Evaluations) and CAFTA (Computer-Assisted Fault Tree Analysis) addressing the potential Failure Modes and Effects Analysis (FMEA) and associated contributions to existing Plant Final Safety Analysis Reports (PFSAR) in terms of Large Early Release Frequency

(LERF) and core frequency damage, as well as plant security and industry safety consideration and requirements

- Potential regulatory and authorization considerations and guidance relative to the PFSAR
- Secondary markets for hydrogen use, including petroleum refineries, steel manufacturing, and substitute hydrocarbon fuels synthesis (referred to as synfuels).

3. GRID STABILITY AND RESILIENCY

Existing NPPs significantly contribute to grid stability through the rotational inertia provided by their large turbines. Efforts to integrate hydrogen with U.S. NPPs not only promotes the economic stability of the unit(s) but also serves to maintain the stability and resiliency of the power grid.

The FPOG Pathway in DOE-NE is sponsoring work in evaluating the value of existing nuclear energy to the reliability and resiliency of the North American electric power system. The details of which will be available in a milestone report that will be published with unlimited distribution by the end of September 2024. This work will feature models of transmission systems, including generation and demand, in at least two regions of the U.S. relevant to NPPs. Those models will be used to show the impact to the electric grid if nuclear power is removed from the grid at levels ranging from a single plant to all existing reactors. Extenuating conditions will also be considered, such as droughts, heat waves, extreme cold weather, and substantial increases in electric power demand such as from the massive build-out of data centers. Figure 3-1 shows the results from a nationwide, long-term reliability assessment from the North American Electric Reliability Corporation (NERC) and illustrates the West and Midwest are specific areas of concern. Some utilities in Midwest are identified as high-risk (highlighted with red in Figure 3-1) because of their inability to meet resource adequacy requirements mandated by NERC. This is particularly in light of planned coal phase-out over next 5-10 years, causing severe shortfall of firm capacity to balance the grid under the scenarios mentioned.

Figure 3-1. Risk area summary from NERC's Long-Term Reliability Assessment 2023. Altered from [3].

Understanding the impact to the reliability of the bulk electric system due to any reduction in generation capacity from nuclear power for any reason is the motivation of this work. Some factors that might lead to premature/unplanned closure of nuclear plants, extended outages, or repurposing of nuclear power include

- Aging infrastructure. Many NPPs in the U.S. are nearing the end of their designed operating lives. Upgrading aging infrastructure can be expensive, and some utilities may choose to retire plants rather than invest in costly upgrades.
- Low wholesale electricity prices. The deregulation of the electricity market in many states has led to increased competition and has driven down wholesale electricity prices, causing nuclear power operators to seek other revenue sources for their heat and power such as hydrogen production.
- Renewables growth. The rapid growth of renewable energy sources, such as solar and wind power, is posing a challenge to traditional generation sources, such as nuclear. While renewable power sources are usually perceived as key parts of the clean energy transition, their intermittent nature requires additional grid solutions for reliable power supply. The challenge becomes greater when additional consideration are taken into account, such as must-schedule or must-dispatch practices for wind and solar power.
- The potential for regulatory decisions to be in conflict. Environmental Protection Agency (EPA) Rule 86 FR 880 in 2021 set a compliance date for the ban on processing and distributing Decabromodiphenyl Ether (DecaBDE). DecaBDE, which is featured in many safety-related components, particularly wiring, of NPPs such that this rule could have impacted several plants. If the rule had been enforced, three plants would not have been able to restart after their 2023 spring outages and numerous others would have experienced issues in the near future. Fortunately, in this case, the EPA provided relief to the nuclear energy industry [4,5].

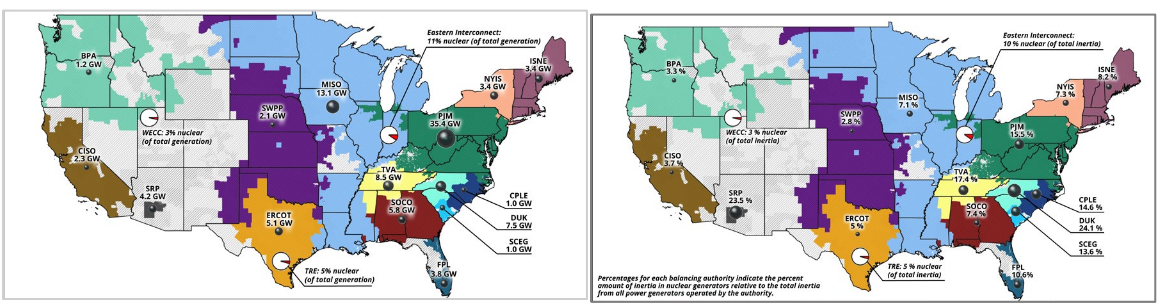

Figure 3-2. Capacity of NPPs per balancing area and portion of capacity by interconnection in comparison to total power generation capacity (left) and contribution of synchronous machine spinning inertia on a per balancing authority and interconnection basis (right).

Figure 3-2 provides a summary of the significant role nuclear energy plays in the United States' power generation mix, providing around 20% of the nation's electricity generation, spread across 28 U.S. states. Nuclear power is a reliable source of baseload power that is mostly unaffected by short- or long-term weather patterns. In terms of capacity, PPs have as much as 26% of balancing area power generation capacity. Nuclear power provides a substantial contribution (e.g., 10% of the inertia in the Eastern Interconnection) of the synchronous spinning mass/inertia that buffers the rate at which frequency changes when load and generation imbalances occur (e.g., a large plant trips or a load is suddenly shed due to a transmission outage). This contribution is critical for maintaining grid stability during sudden changes in load or generation [6].

A rapid analysis method has been developed that provides results for the economic, environmental, and reliability impacts of removing nuclear generation. The method relies on a supply curve model for economic and environmental assessments and a Monte Carlo simulation model for reliability analysis, given the current resource in two regions of the Eastern Interconnection shown in Figure 3-3. The method has been demonstrated for the ReliabilityFirst/Electric Reliability Organization (ERO)/Pennsylvania-New Jersey-Maryland (PJM) Interconnection, LLC area of the Eastern Interconnection as well as the Midcontinent Independent System Operator (MISO). Example economic results of this analysis are shown in Figure 3-4 in which the supply cost curve shows the impact of removing baseload nuclear from the mix. For both interconnections, removing nuclear causes the marginal cost to increase more rapidly with increasing grid capacity. For example, removing nuclear power from the power supply in the PJM Interconnection causes the first knee in the marginal cost curve to shift from approximately 80,000 MW of capacity down to approximately 40,000 MW of capacity.

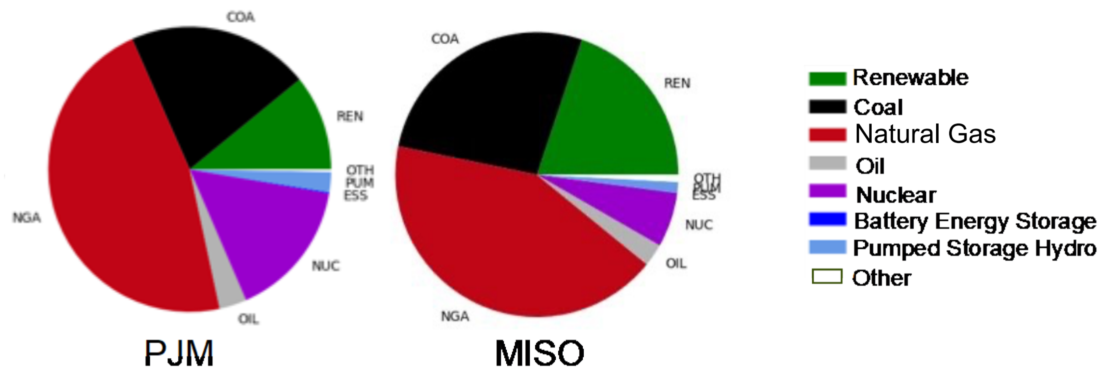

Figure 3-3. Capacity mixes in PJM and MISO by fuel category [6].

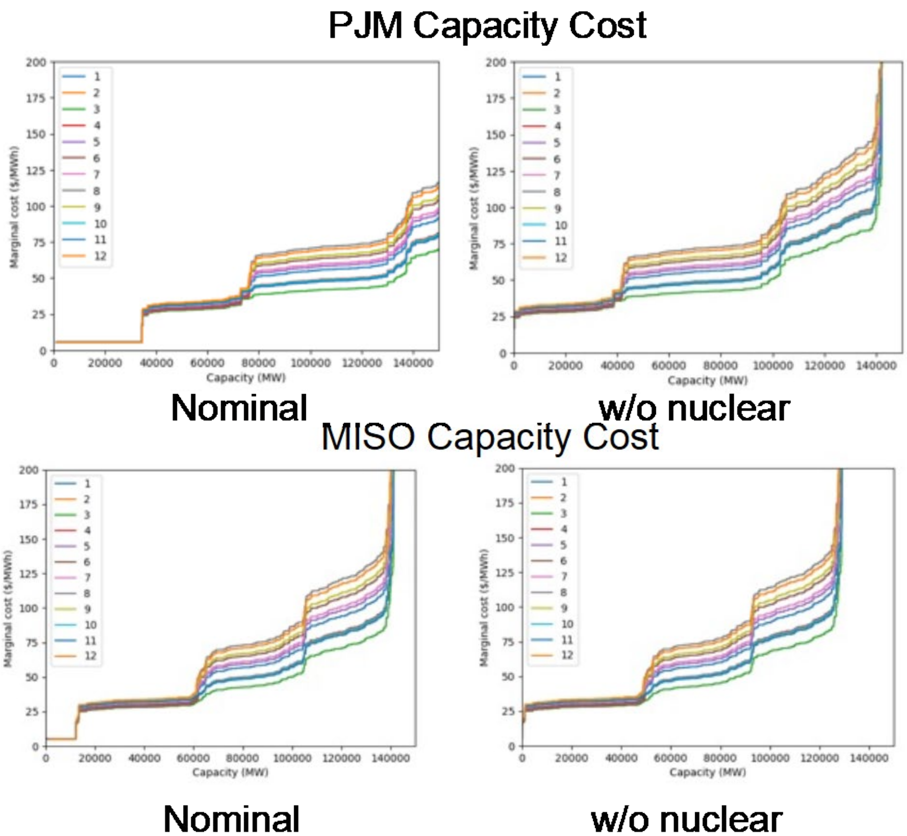

Figure 3-4. Supply curves of the PJM/MISO region by month of the business-as-usual (BAU) scenario (left) and worst-case scenario (right). Note that the curves are capped at $200/MWh for readability. Only the capacity of dispatchable resources (i.e., thermal units) in the supply curve was included.

More detailed modeling has also been conducted that includes transmission constraints and comprehensive production cost modeling with unit commitment and dispatch that considers potential outages. The model can be reconfigured based on assumptions about retirements, installation of new energy assets, and load profiles for projected scenarios. Furthermore, the model has been employed for a comprehensive demonstration involving the Western Interconnection or Western Electric Coordinating Council area for scenarios representative of past extreme events (e.g., drought and heat waves). A similar model has been prepared for the Eastern Interconnection and corresponding demonstrations are being performed for that area. Results of various scenarios are highlighted in Figure 3-5 that show unserved loads result for scenarios of drought and/or heat waves when some or all nuclear power is not available. These modeling efforts provide the mechanism to evaluate the reliability of the grid with respect to customers whose electric service would be impacted if nuclear generation is lost, even temporarily. These efforts also give insight into desirable outcomes if some nuclear plants become coupled to hydrogen plants in such a way as to enable greater flexibility in power that is dispatched to the grid. In that scenario, curtailing hydrogen production during times of stress on the power grid may be required to maintain a stable grid.

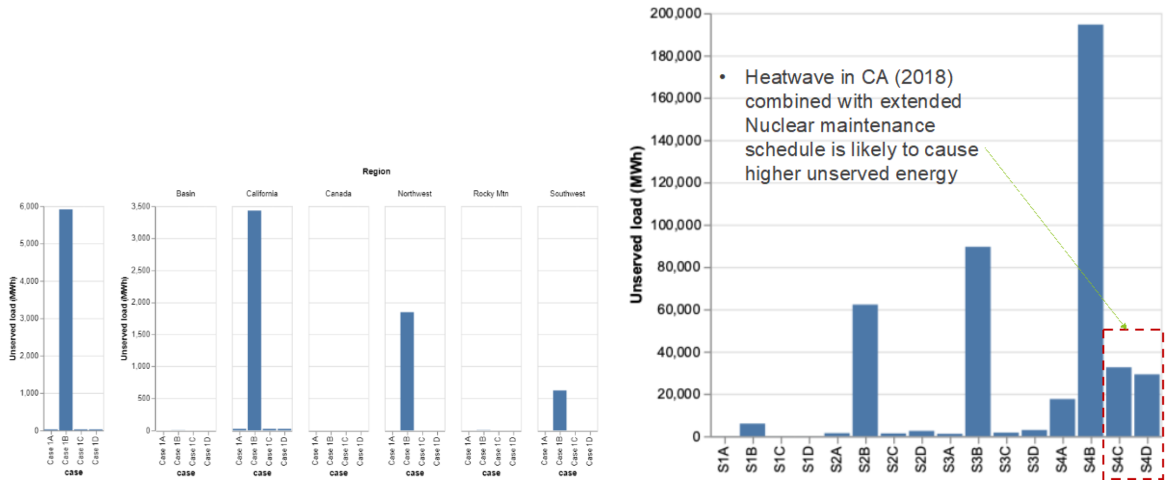

Figure 3-5. Effects of extreme events, such as heatwaves or droughts, on unserved loads in scenarios in which some or all the nuclear power is effectively off-line due to retirements or unplanned outages

4. HYDROGEN MARKET ASSESSMENT AND INTEGRATION OPPORTUNITIES

4.1 Comparative Assessment of Hydrogen Production Alternatives

Research efforts coordinated under the LWRS program have been motivated by global efforts to reduce fossil fuel dependence and to electrify energy-related processes that emit high levels of carbon dioxide. Electrification offers opportunities to use wind, solar, and other low carbon sources of energy to reduce fossil fuel consumption of transportation and carbon-intensive industries. However, many industries, such as chemicals, fertilizers, liquid fuels, steel, and cement, benefit from nonelectric sources of energy such as hydrogen. The efficiency and cost of producing hydrogen using clean technologies must become competitive with fossil-fuel-based methods to enable a rapid decarbonization of these commodity-based industries.

Producing low carbon hydrogen at a competitive price is one of the challenges that presently limits hydrogen's adoption as a solution to reach net-zero emission targets set by DOE by 2050. The conventional process, and currently the least expensive option for producing hydrogen, is referred to as steam/methane reforming (SMR-H2) and uses natural gas as a feedstock. SMR-H2 combines steam and high-temperature heat to convert natural gas and other hydrocarbon-rich gases into H_2 and CO_2. To provide a low-emissions hydrogen, the CO_2 must be captured and sequestered. Additionally, the production of natural gas results in fugitive emissions of CH_4, which absorbs much more heat than CO_2. Hence, the challenge for reducing the carbon footprint for SMR-H2 hydrogen is two-fold.

$$H_2O\text{ (steam)} + CH_4\text{ (natural gas)} + (O_2) \xrightarrow{\textit{Reforming Process}} H_2 + CO_2 \quad \text{[SMR-H2]}$$

Alternatively, electrochemical or electro-thermal (electrolysis) technologies that can split water into hydrogen and oxygen have dramatically improved in recent years [7]. Low temperature (<100°C) technologies only require electricity for electrolysis and include PEM and alkaline electrolysis (AE). Alkaline electrolysis plants already operate at scales of multiple 100s of megawatts but suffer from relatively high specific energy consumptions in the range of 54–70 kWh/kg-H_2 [7]. PEM electrolysis is less mature but is already available at tens of MW scale. The efficiency of PEM systems is expected to increase to approximately 52 kWh/kg-H_2 by around 2025 [8,1]. Either AE or PEM electrolysis can be implemented through a power connection to the NPP. Obviously, this connection can be made before or after the power transmission station or by a new high-power voltage line.

A more energy-efficient, high-temperature process is advancing to commercial operation that produces hydrogen and oxygen gas via electrolysis across a solid oxide electrolysis cell (SOEC). This process, known as HTSE, splits water vapor (steam) by applying an electrical potential across the SOEC. SOEC systems are currently being deployed at megawatt scale utilizing no precious metals with reported efficiencies of 38–42 kWh/kg-H_2 [9,9]. The deployment scale of HTSE systems is expected to increase rapidly based on announcements by multiple companies of new facilities that can produce HTSE systems at scales greater than 500 MW_{DC}/yr (DC megawatts per year) [11,11].

Figure 4-1 illustrates the relative energy consumption for AE, PEM, and SOEC technologies. The efficiency of an electrolysis process is inversely related to the voltage potential that is required between the cell electrodes. The required voltage is approximately 1.3 V for HTSE, 1.75 V for PEM, and 2 V for AE. HTSE has a lower voltage requirement because less energy is required to split steam molecules than liquid water molecules. Figure 4-2 illustrates the various pathways toward hydrogen production and use in decarbonizing industrial needs.

The availability of thermal and electrical power at existing U.S. NPPs provides an opportunity for large-scale production of clean hydrogen with an integrated HTSE process. To adequately assess the benefit of HTE with nuclear power, the LWRS program sponsored an activity to compare the relative benefits of different clean energy resources for steady production of hydrogen at a scale of 500 MW [13].

The study included a techno-economic assessment (TEA) of these sources of clean electricity and/or heat to produce hydrogen through electrolysis to compare the economic viability of both LTE and HTSE technologies. The comparative analysis indicated that NPPs are the most economically viable for baseload hydrogen production facilities, outperforming renewable-based facilities with significantly lower levelized cost of hydrogen (LCOH). Renewable-based facilities faced challenges due to daily and seasonal generation variation, resulting in large installation sizes and lower capacity factors even under the best-case scenarios for resource availability, incentives, and export prices. In comparison, the high-capacity factor of nuclear power provided superior utilization of capital to reduce hydrogen production costs.

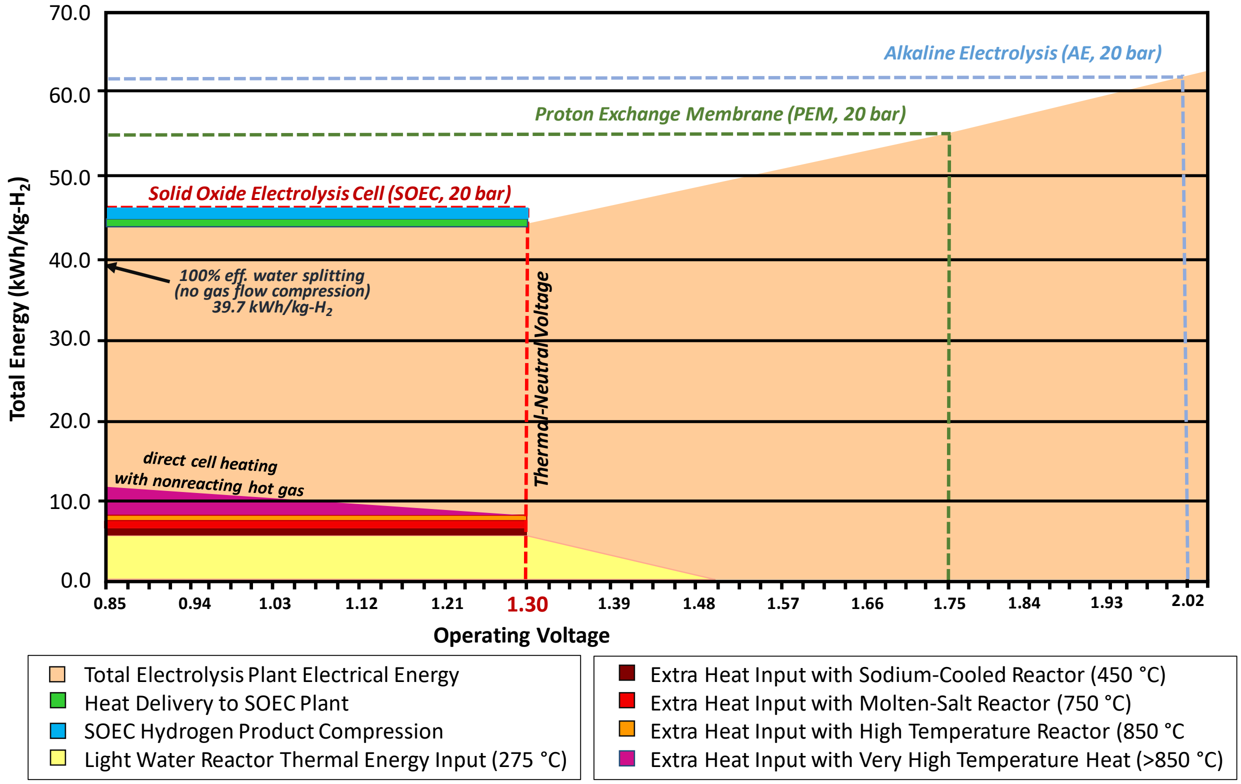

Figure 4-1. Comparative estimates for power consumption for AE, PEM, and SOEC.

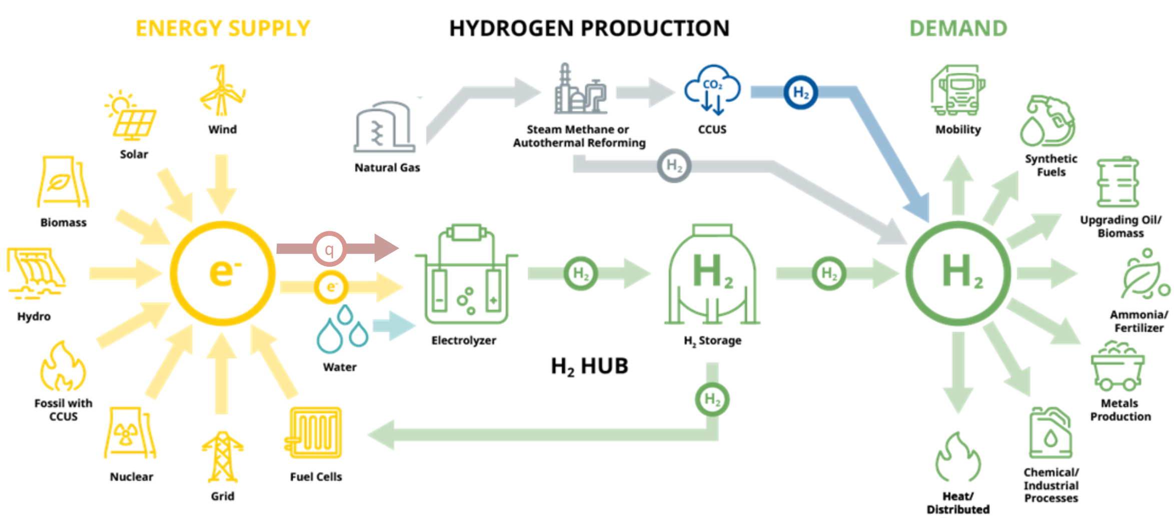

Figure 4-2. The potential ecosystems for producing hydrogen for decarbonization of industry.

4.2 HTSE Technology Review

The efficiencies noted for SOEC systems are predicated on the energy consumption at the solid oxide cell level. Additional heat is required to convert the process water flow to steam for electrolysis. Joule heating is one option, but the use of nuclear heat offers an opportunity for improved efficiency. Steam from the nuclear plant is not necessarily used directly for electrolysis but can provide the heat needed to boil demineralized water that feeds into the HTSE process. A significant amount of research has been completed under the LWRS program to assess the feasibility and cost of producing hydrogen using a combination of electricity and heat from nuclear plants.

Figure 4-3 shows a high-level process flow diagram (PFD) of a generic HTSE system [14]. Engineering considerations indicate that practical designs restrict the use of heat to producing steam at 150–180°C. The heat input is represented by the block arrow labeled "Heat" in Figure 4-3. With an optimized design to minimize heat losses, the specific heat requirement to produce steam for HTSE is 6.4 kWht/kg-H_2 [7]. Electricity is used to provide topping heat for fuel and sweep air entering the electrochemical cells (labeled "Electric Heat") and for facilitating the water-splitting reaction in the electrochemical cells (labeled "Electricity"). The minimum specific electric energy requirement for HTSE systems has been reported as 36.8 kWh/kg-H_2 [7].

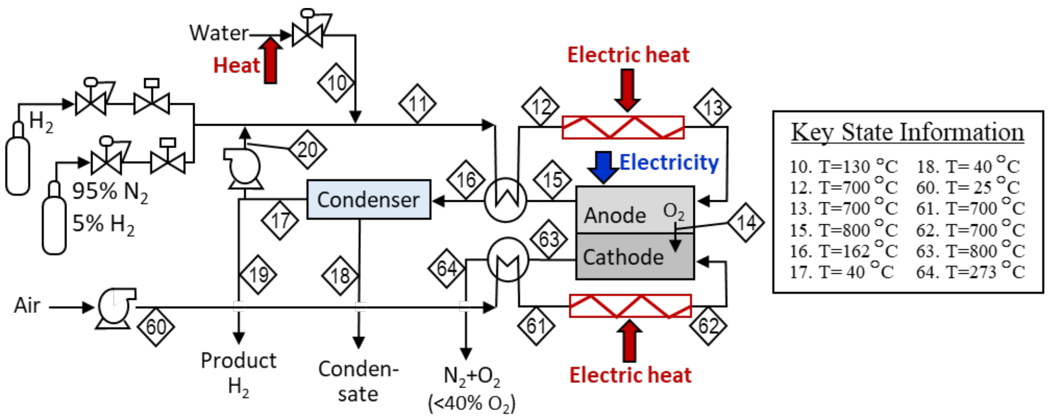

Figure 4-3. Simplified PFD of a generic HTSE system.

The SOEC process illustrated in Figure 4-3 initiates with the process fuel—a mixture of approximately 95% demineralized steam and 5% hydrogen—being fed into the cathode side of the solid oxide cells. Concurrently, air sweep gas is introduced into the anode side. The small amount of hydrogen flow into the cathode side prevents unwanted oxidation of the fuel catalyst material. Heat exchangers simultaneously heat the incoming fluids while cooling the products. The temperatures of the exiting fuel and air sweep gas are approximately 160°C and 270°C, respectively. The relatively high temperature of the exiting sweep air stream is due to the greater amount of mass flowing out of the anode side than the flow moving in. This mass imbalance is due to the transfer of oxygen ions from the cathode side to the anode side through the electrolyte. In a conventional SOEC system, the mass flow rate of sweep air is maintained sufficiently high that the oxygen concentration of the exiting sweep gas is less than 50% to reduce hazards associated with high-temperature, oxygen-enriched air. Similarly, the relatively low temperature of the product fuel (hydrogen) stream is due to the lower mass of product hydrogen flowing out of the cathode compared to reagent steam that enters it. This is because of the transfer of oxygen ions across the electrolyte. A condenser downstream from the fuel heat exchanger cools the product hydrogen to reduce its moisture content. Additional heat exchangers (not shown) are used to recover heat from the exiting sweep gas and maximize the thermal efficiency of the process. Naturally, in deployments of large megawatt systems, heat in the exiting sweep gas and product hydrogen can be used to assist in providing steam for the process, as described in more detail in References [7,15].

HTSE demonstration testing has been completed at INL to provide data from a physical SOEC system to verify theoretical predictions. A collaborative effort between INL (Battelle Energy Alliance) and Bloom Energy facilitated a performance demonstration of multiple 100 kW Bloom Energy units that produced hydrogen at 0.75 kg/hr. A photograph of a Bloom system is shown in Figure 4-4. Adjacent to the Bloom unit are all attendant demonstration test equipment and facilities provided by INL, including an electric steam boiler, AC/DC power rectifiers, electric supply (480 VAC) hydrogen process heaters, blowers, and other equipment.

Figure 4-4. Photograph of a Bloom prototype 100 kW SOEC system installed at INL.

The Bloom Energy 100 kW SOEC systems have been operated at INL in excess of 5,000 hours. Figure 4-5 shows the hydrogen production rate as provided by Bloom, the measured DC power consumption, and the steam flow to the system for first 2,200 hours of testing.

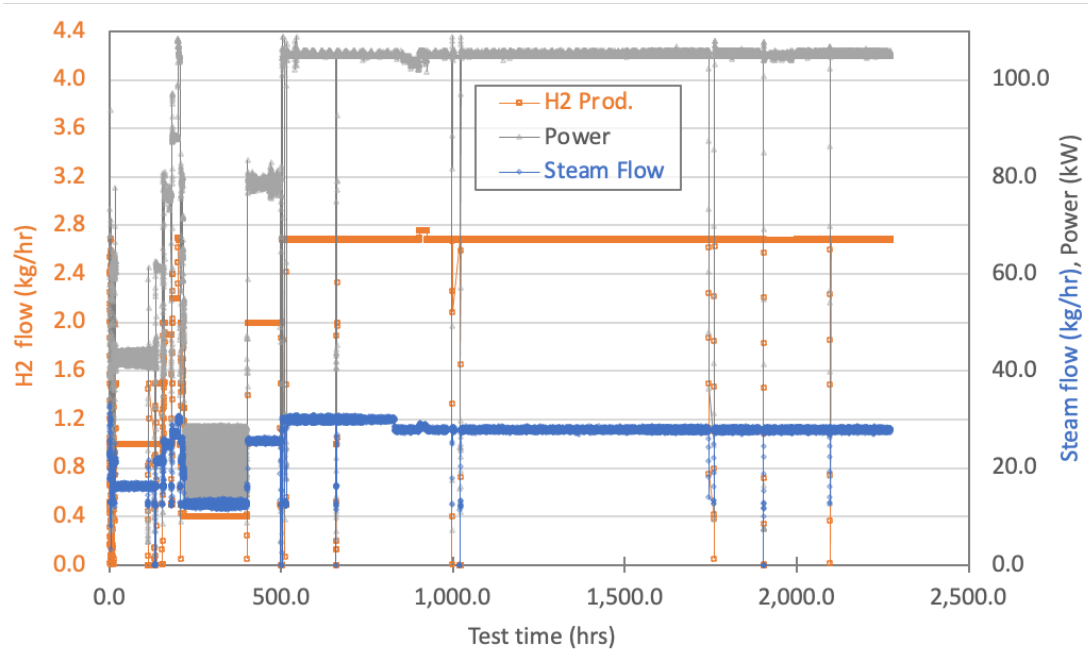

Figure 4-5. Operating data from the 100 kW Bloom SOEC system through September 2022 [14].

Additional information regarding the testing results are presented by Casteel, et al. and in "Validation of a Reduced-Order PWR Power Dispatch Simulator" [16,14]. General observations include excellent performance during all planned testing evolutions, and the results substantiate the power consumption estimates described above. It is noted that Figure 4-5 exhibits numerous transients during the full testing duration and represent facility test support issues (power loss) and are not indicative of SOEC failure.

Of particular interest to this project is a dynamic de-load test, which was performed after approximately 634 hours of operation, as shown in Figure 4-6. This test was performed to verify the system's ability to respond to dynamic loading requests as a dispatchable power load. During this test, the system was ramped down from 100% power (106 kW) to 19.5% power (20.7 kW) in 10 minutes, validating expected performance.

These on-going testing programs support manufacturer performance data and have produced highly credible reliability data in support of performance and long-term cost estimates. The testing results also show the capabilities of these systems to respond to variable demand requirements, which support the concept of enabling variable hydrogen production as NPPs respond to renewable generation.

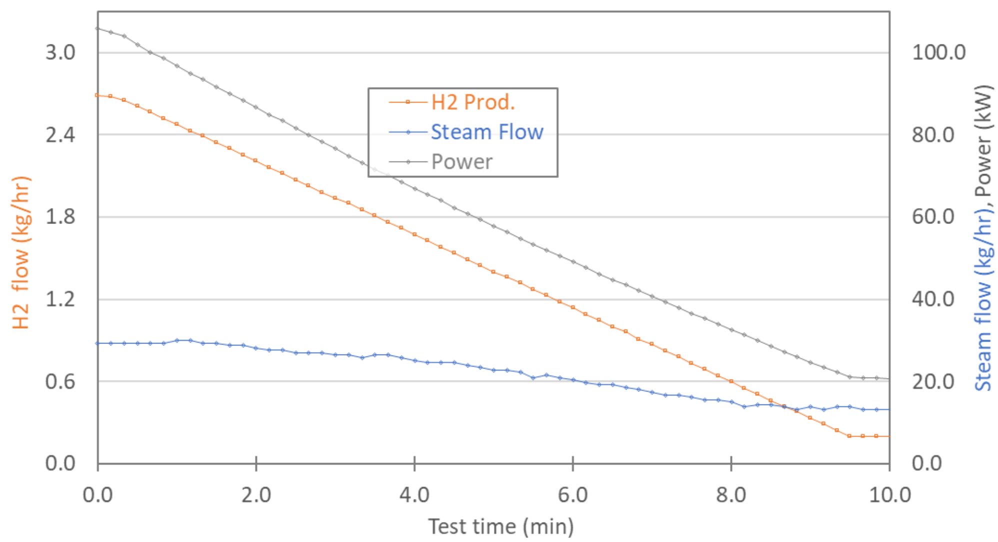

Figure 4-6. Results of a dynamic de-load test with a rapid ramp from 100% to 20% power.

4.3 Hydrogen Production Cost and Market Assessment

In this section, three business case options are introduced and explained to provide a basis for a project-specific economic analysis, which is a key element in the strategic integration plan. The tools and methods that have been developed and are available for the assessment of economic value of integrated hydrogen systems are presented here.

In collaboration with the DOE Hydrogen and Fuel Cell Technologies Office (HFTO), the LWRS program and the Nuclear Integrated Energy Systems (IES) program have developed analysis and implementation tools that can be used to assess the business case for NPP hydrogen production. Three operating paradigms have been considered. Each case requires a business arrangement with a hydrogen gas company, unless the utility is considering a multi-market option.

Business Case 1. Continuous, steady-state hydrogen production, in which a power-purchase agreement is made with the nuclear plant and the power is dedicated exclusively to hydrogen production.

Business Case 2. Flexible operation of the hydrogen plant, in which case the NPP can rapidly switch back and forth between supplying power to the grid and supplying power to the hydrogen plant to optimize overall profitability. In theory, hydrogen will be produced when the electricity grid market price is low, and power is sent to the grid when the price of electricity is high. This business case is more complicated because the agreement between the hydrogen plant owner and the NPP must include terms for switching between the two markets. With flexible operations, the NPP may function as a dispatchable reserve capacity, in which case capacity payments may be received from the grid operator. The value of selling electricity at a higher price and potential capacity payments could reduce power pricing to the hydrogen plant to increase competitiveness.

Business Case 3. Hydrogen is produced and stored during off-peak hours when generation capacity exceeds demand and then is used to produce additional power during periods of peak demand. This case may be appealing to utilities with high wind and solar generation necessitating various scales of energy storage. This case has the potential for the grid operator to take full advantage of the NPP capacity, except during periods of refueling. Depending on the hydrogen energy storage capacity, it will be used for power production on long time scales ranging from hours to weeks.

4.3.1 Business Case 1 - Continuous Hydrogen Production

For purposes of discussion in this section, Figure 4-7 illustrates a generalized connection between an NPP and a hydrogen plant. A detailed architecture/engineer conceptual design is discussed later in this report. To complete an initial investor-grade technical and economic assessment, it is first essential to develop a basis for the plant upgrades and capital investments that are needed to couple the nuclear plant to the hydrogen plant, in addition to the capital costs of the hydrogen plant itself. Second, a conceptual design is necessary to estimate the operating costs, as well as project engineering, plant construction, and startup costs.

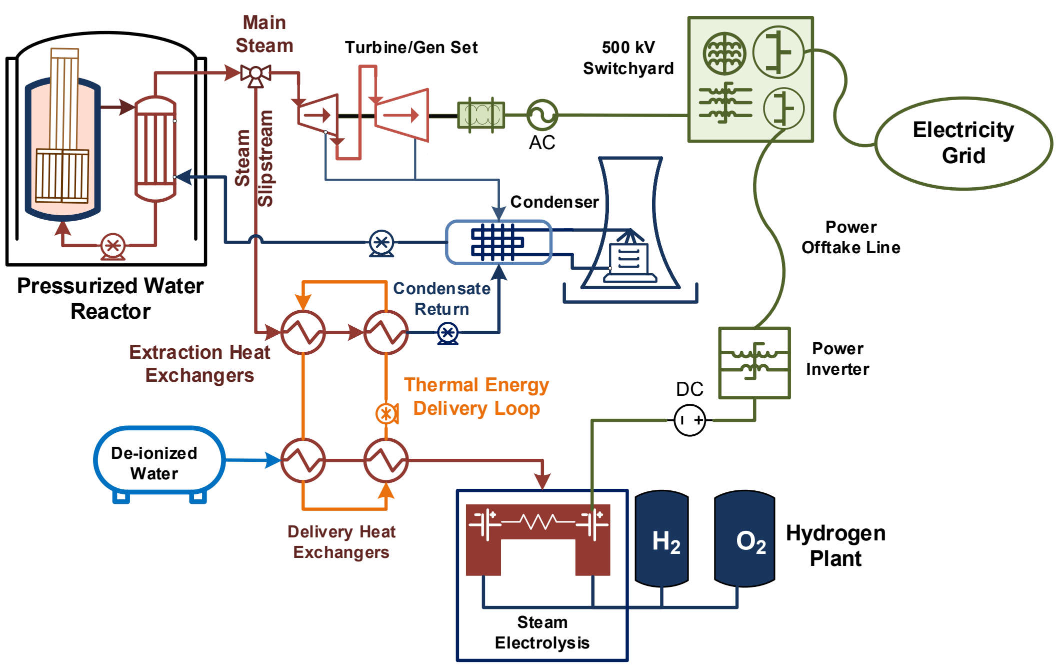

Figure 4-7. Conceptual design of a hybrid FPOG plant producing hydrogen and grid electricity.

An NPP/HTSE project analysis tool (NPP-HTSE H2 profitability tool) has been developed using Microsoft Excel to calculate (1) discounted cash flow and LCOH analysis, (2) sensitivity analysis with respect to the selected financial performance metrics and outputs of tornado charts, (3) profitability analysis represented by heat maps using the two most sensitive parameters, (4) electricity versus hydrogen production preference analysis by comparing the delta net present value (ΔNPV) between NPP-HTSE and BAU electricity production for the grid, and (5) competitiveness analysis by comparing the calculated LCOH for NPP-HTSE with that of SMR-H2, which is the conventional process to produce hydrogen [17]. The calculator is based on the following project and financial parameters:

- A detailed breakdown of component and equipment manufacturing and capital costs that are scaled according to plant size. This design information is based on a scalable reference modular plant developed by INL and Strategic Analysis [15].
- Electricity power costs, thermal energy costs, and natural gas market price.
- Project financial assumptions; debt and equity ratio; and their respective interest rates, tax rates, project life, capacity factor.
- The hydrogen market price per kilogram of hydrogen.

The NPP-HTSE spreadsheet tool is available for public use. User instructions are given in the model. Any of the default input parameters are adjustable through a user dashboard screen of inputs and solvers (shown in Figure 4-8) to allow the sensitivity analysis of energy pricing, tax liabilities and/or tax incentives, plant scale, and capacity factor. Correlation-based models are used to account for the interdependency among hydrogen market price, electricity price, and natural gas (NG) price.

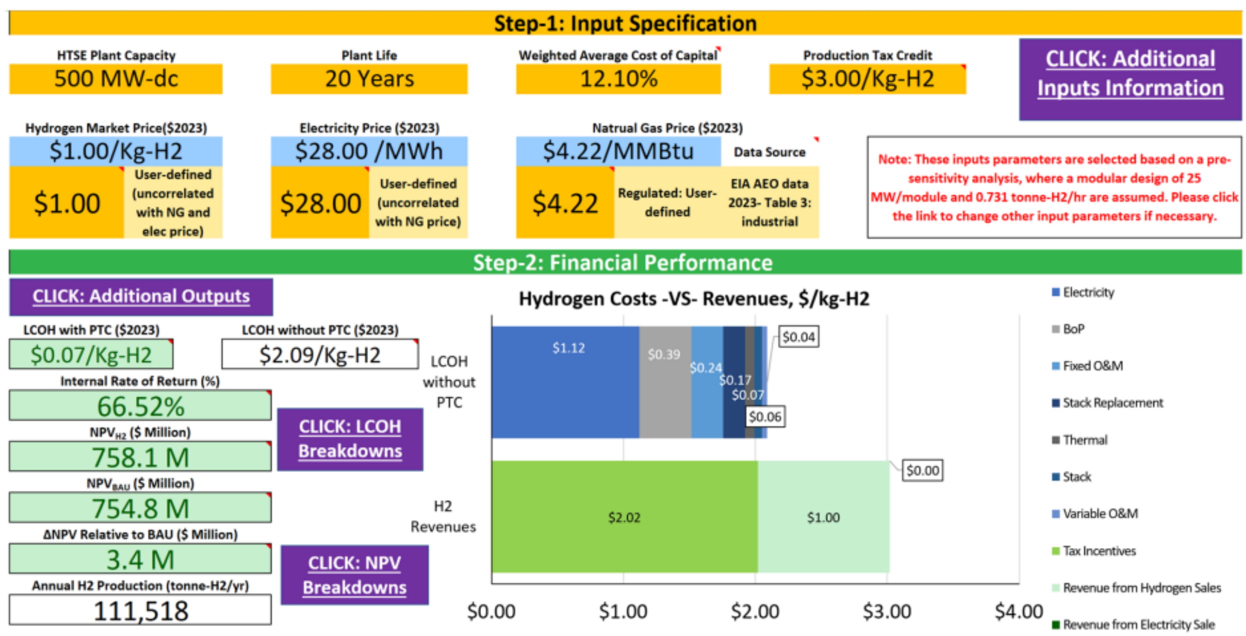

Figure 4-8. Screenshot of NPP-HTSE H2 profitability tool showing user input specification (yellow fields) and calculator button (purple fields).

For this reference example, the plant size is 500 MW_{DC}, the plant life is 20 years, the Weighted Cost of Capital (WACC) was calculated as 12.10%. A market selling price for hydrogen of only \$1.00/kg-H_2 was tested. This is considered the floor for hydrogen production through SMR-H2 of natural gas. The reference cost of electrical power was set at \$28/MWh for the electricity price. This is lower than what most NPPs are selling electricity to the grid, but nonetheless shows how nuclear hydrogen may compete with conventional SMR-H2 hydrogen plants.

The competitive analysis feature of the tool allows a comparison of hydrogen production with the conventional production of hydrogen via SMR-H2, as shown in Figure 4-9. The electricity price varies from \$0/MWh to \$120/MWh, and the price of natural gas varies from \$0 MMBtu to \$15 MMBtu. The manufacturing price of SMR-H2 hydrogen is shown with and without carbon capture and sequestration. These two plots manifest the break-even points for HTSE versus SMR-H2. The importance of the production tax credit (PTC) is manifest for such a first-of-its-kind plant based on the current capital and operating costs specified in the spreadsheet input fields. The user can access the sensitivity of each input specification with respect to LCOH without PTC, NPVH_2, and NPVBAU (net present value, business as usual), as seen in Figure 4-10. For this example case, the hydrogen market price and the PTC are the most sensitive parameters affecting the NPV.

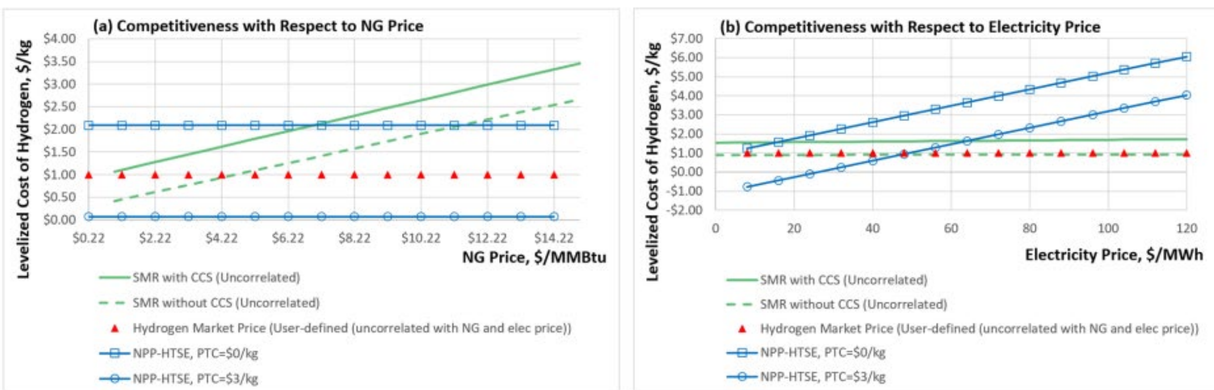

Figure 4-9. Competitive analysis for reference example with 500 MW_{DC} of HTSE design capacity, 20-year plant life, 12.10% WACC, and \$1.00/kg-H_2 hydrogen market price [17].

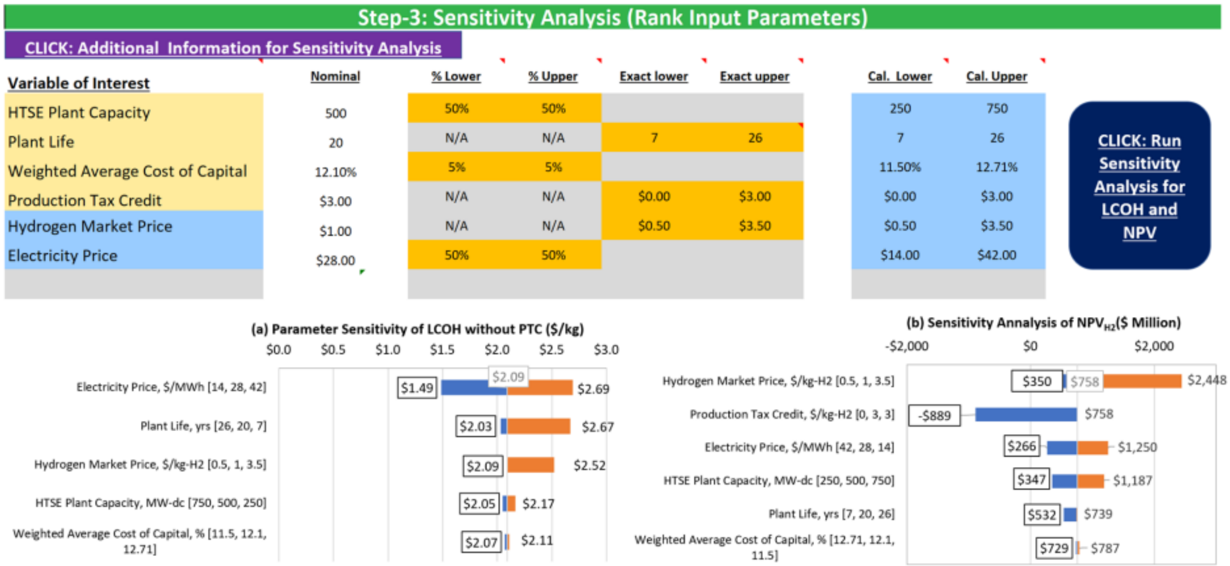

Figure 4-10. LCOH and NPVs based on major project and financial parameters (without PTCs).

The hydrogen market price and production are selected for the profitability analysis represented by heat maps, as shown in Figure 4-11, to illustrate this feature of the tool. The region of maximum profitability (i.e., the region where the Internal Rate of Return is greater than WACC of 12.1% and NPV is positive) is on the lower right side of the heat map.

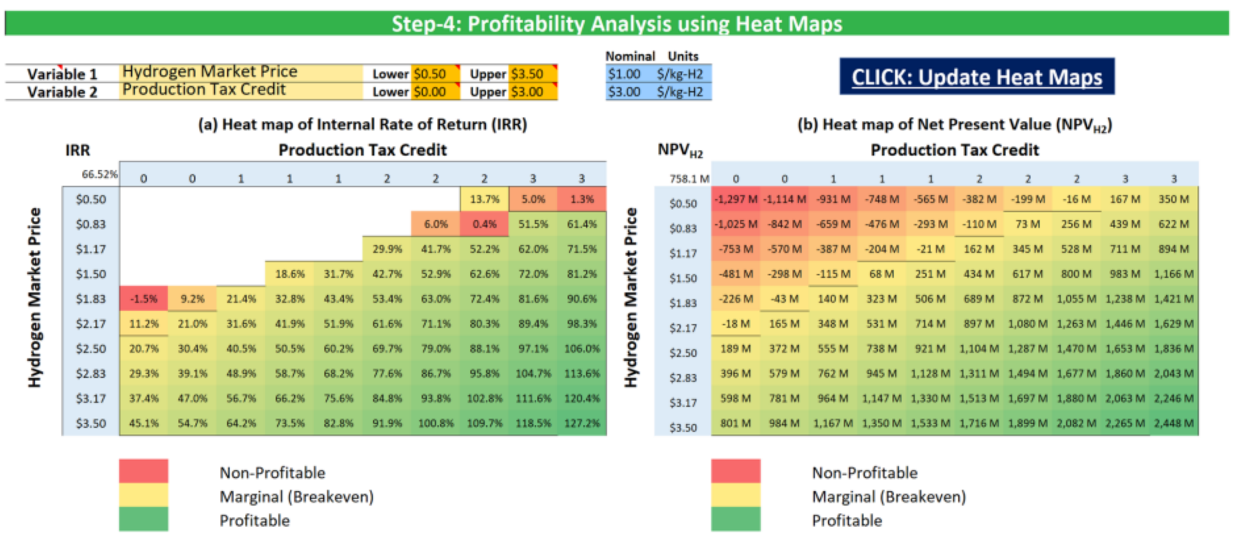

Figure 4-11. Profitability heat maps for reference case.

Lastly, Figure 4-12 helps determine the conditions in which hydrogen production is more profitable than business as usual. The favorable region falls within the green triangle, which is bounded by market conditions, including the market price of hydrogen, the wholesale price of electricity, and the maximum hydrogen PTC. In this case, the preferable region lies where NPV-H_2 is greater than NPVBAU and is bounded by the NPP-BAU, maximum hydrogen market price, and the lower bound of electricity price, indicating that cases with electricity prices between $59.5/MWh and $0.3/MWh are preferred for hydrogen production.

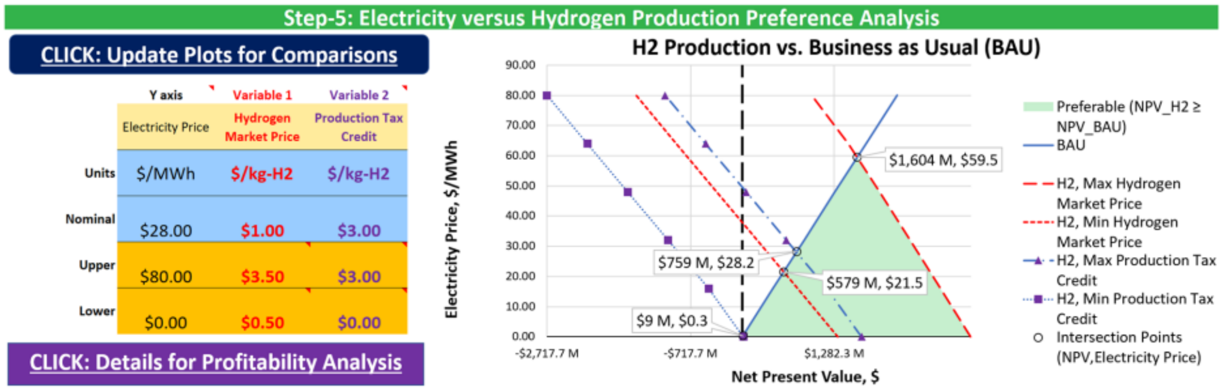

Figure 4-12. Hydrogen production preference analysis.

4.3.2 Business Case 2- Dynamic Hydrogen Production

The demand for NPP operational flexibility is projected to increase as variable renewable generation capacity continues to rise. This presents a unique market case for nuclear hydrogen production, which takes advantage of market conditions to optimize revenue. Figure 4-13 illustrates how electricity produced at the marginal electricity selling price could be sold to the grid or used to generate hydrogen. In this case, the system may be viewed as a price taker so far as it will schedule ahead for the power market anytime the marginal electricity price exceeds some price point (referred to herein as the switch-over price). When the marginal price of electricity is high, the HTSE is rapidly turned down to dispatch electricity to the grid. Conversely, when the price of electricity is low, then the plant will ramp up hydrogen production. Naturally, in order to supply hydrogen to a dedicated industrial user, hydrogen storage will be necessary. Hybrid production of hydrogen leads to an opportunity to deploy a reversible SOFC/SOEC system in which the hydrogen produced below the cut-off price is stored to produce electricity when the price of electricity rises above the cut-off price. Alternatively, hydrogen could be supplied to a hydrogen capable gas turbine.

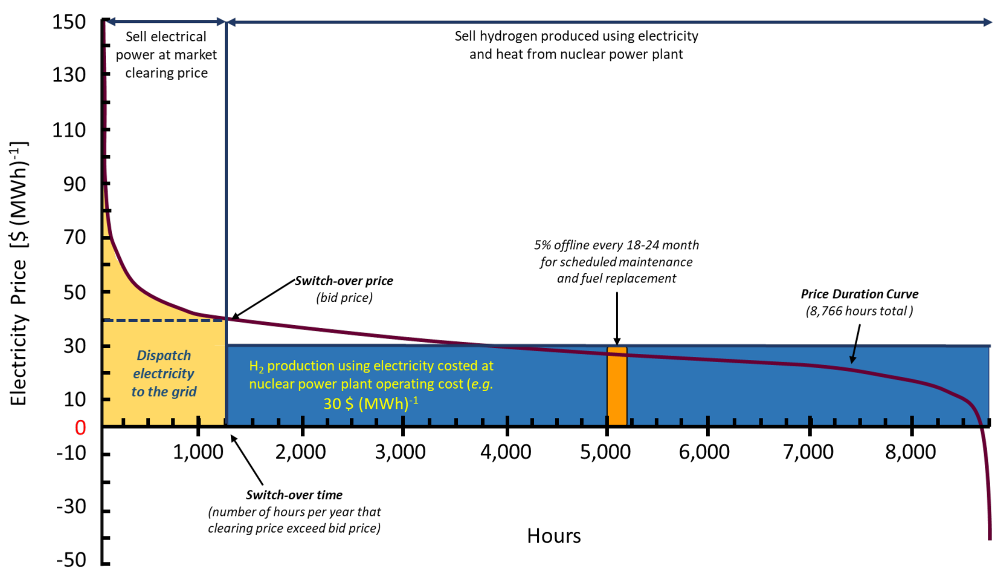

Figure 4-13. Hybrid nuclear power/hydrogen plant concept for the price-dependent electricity market.

To analyze the economic viability of hybrid operations, particularly given the uncertainty surrounding load demand, electricity prices, and the availability of variable power generation resources, a model framework called FORCE[d] (Framework for Optimization of ResourCes and Economics) has been developed. FORCE is based on a collection of transient process models developed in the Modelica language or other models that can be translated to reduced-order models through functional mockup integration as a functional mockup unit. The library of transient codes is referred to as HYBRID. These models are solved iteratively with HERON (Holistic Energy Research Optimization Network) with real-time operating control constraints that are managed by a third routine referred to as ORCA (Optimization of Real-time Capacity Allocation). Overall FORCE is used to conduct analysis of the technical and economic viability of a range of possible nuclear energy IES configurations and, at the end, to optimize those configurations based on specified location, weather and grid demand conditions.

As an example of how this capability has been used, a case for dynamic production of hydrogen and power for the grid was studied for a deregulated power market in the upper Midwest [18,18]. The objective was to maximize revenue for the system. Electricity and hydrogen flows are tracked for five components: (1) an electricity source (balance of plant; BOP), (2) a hydrogen production facility (HTSE) that consumes electricity to make hydrogen, (3) an electricity market (electric grid) that consumes electricity, (4) a hydrogen storage unit (H2_storage), and (5) a constant hydrogen consumer (H2_market1). A predicted 72-hour dispatch of power from a NPP is reproduced in Figure 4-14. The graphs show the operation of each unit in terms of electricity (top), hydrogen (middle), and storage, as well as the price of electricity (bottom). When the marginal price of electricity is low, hydrogen is produced and stored. When the price of electricity nears the cut-off price, hydrogen is taken from storage to supply the hydrogen consumer, so that all electricity produced can be sold on the grid. The performance over the three-day period illustrates how a general dispatch optimization can optimize the profit for a given hybrid NPP.

[d] For more background on FORCE, visit the IES website: https;//ies.inl.gov/SitePages/System Simulation.aspx

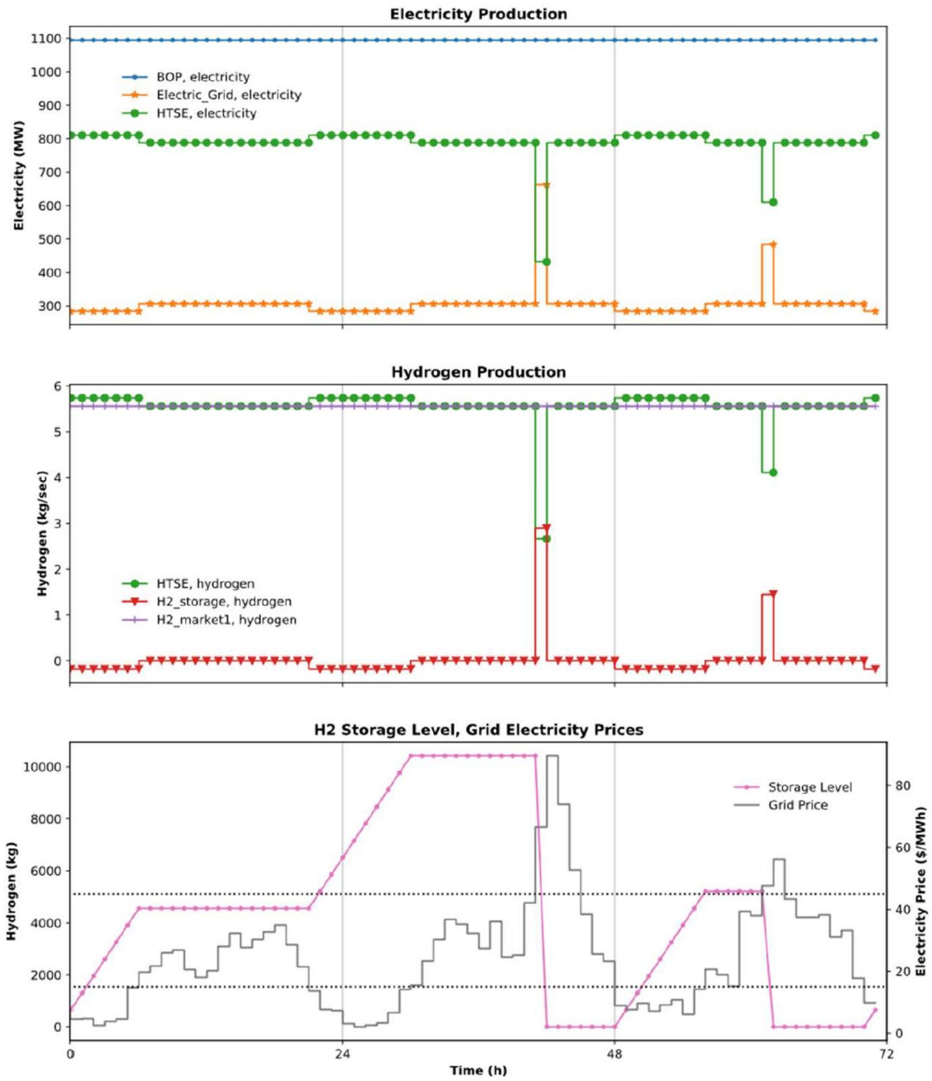

Figure 4-14. Example of plant operation optimization for a hybrid grid/hydrogen market.

For non-regulated power markets, the switch-over price that determines whether electricity is sold on the grid or used to make hydrogen varies according to daily, weekly and monthly swings in power prices. Operations of coupled nuclear plant/hydrogen production system for these conditions has been evaluated previously [14]. The analysis employed a transactive energy management system (TEMS) that accounts for electric and thermal power dispatch to the HTSE plant, representative wind energy, other generators and loads, hourly electricity prices, and potentially variable hydrogen prices in the grid power/market. The TEMS includes both slow and fast loop calculations to determine optimized hydrogen production schedules to maximize revenue while meeting operational constraints. The fast loop calculations provide capabilities to participate in 10-minute and 30-minute spinning reserve markets, while the slow loop calculations focus on optimized economic operations over long time periods of hours and days.

The TEMS was used in an example market simulation for a nominal 100 MW HTSE hydrogen plant operating in the New York ISO during 2019 (8,760 hours). Available hydrogen storage was assumed to be 100,000 kg (100 tonnes), and the capacity factor of the hydrogen plant was assumed to be 80%. Figure 4-15 shows the optimized hydrogen production times as red dots superimposed over the 2019 New York ISO electricity prices. In this scenario, the hydrogen plant ramps down power during times of high electricity pricing but must maintain the daily hydrogen supply quota of 45.1 tonnes-H_2/day, accounting for hydrogen storage, which offers approximately a two-day buffer between hydrogen production and the sales quota.

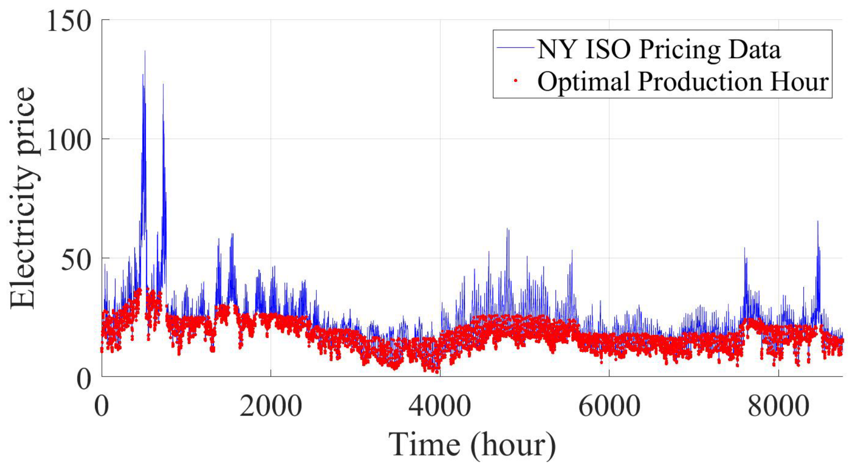

Figure 4-15. Optimal hydrogen production hours (red dots) for a nominal 100 MW hydrogen plant operating in the NY ISO during 2019 with an 80% capacity factor and hydrogen storage of 100 tonnes [14].

It is evident that for optimized operations, the hydrogen plant must ramp up and down rapidly (on the scale of hours or less) to make use of low-cost electricity to reduce hydrogen production costs and maximize revenue from electricity sales from the NPP, even with a relatively large amount of available hydrogen storage of 100 tonnes. Enabling the hydrogen plant to ramp power consumption on the scale of 10-minutes or 30-minutes could enable the NPP to provide 10-minute or 30-minute spinning reserves to the grid and qualify for additional revenue by providing those ancillary grid services. Another interesting feature of Figure 4-15 is that the threshold price point at which the hydrogen plant ramps up and down varies throughout the year, so the control system, the NPP operators, and power dispatchers must respond nimbly to market prices to optimize the operation of the integrated energy system. The switch-over price point changes occur because the average electricity price changes on a daily and weekly basis. For example, electricity prices were relatively high from January 1 through the end of March (0–2200 hours) and from mid-June to mid-August (4100-5500 hours), so the switch-over price at which hydrogen production had to ramp up and down during those times had to adjust accordingly. The hydrogen storage capacity of 100 tonnes and an operating capacity factor of 80% result in a requirement that the hydrogen plant operates approximately 38 hours in each 2-day window to meet production quotas, regardless of the average daily electricity price.

4.3.3 Business Case 3- Energy Arbitrage Market

Similar to the dynamic hydrogen market business case (Section 4.3.2), the dynamic production of hydrogen for storage and subsequent use as fuel for electricity production may provide economic incentive for integrating an NPP with an HTSE plant. Power production can be achieved using the hydrogen in either a reversible high-temperature solid oxide electrolysis and fuels cell module (rSOEC/SOFC) or a hydrogen combustion turbine (Figure 4-16). This mode of operation may require full or partial cycling of hydrogen production several times a week. In other situations, it may be profitable to produce and store hydrogen to generate electricity during periods when baseload is required (loss of generation assets) or during peak demand. In this case, hydrogen storage will likely be required to ensure a steady supply to a regular off-taker. In the case of energy arbitrage, this will likely require storage up to terra-watt hours (TWh). Any excess hydrogen production can be sold to the market for other uses.

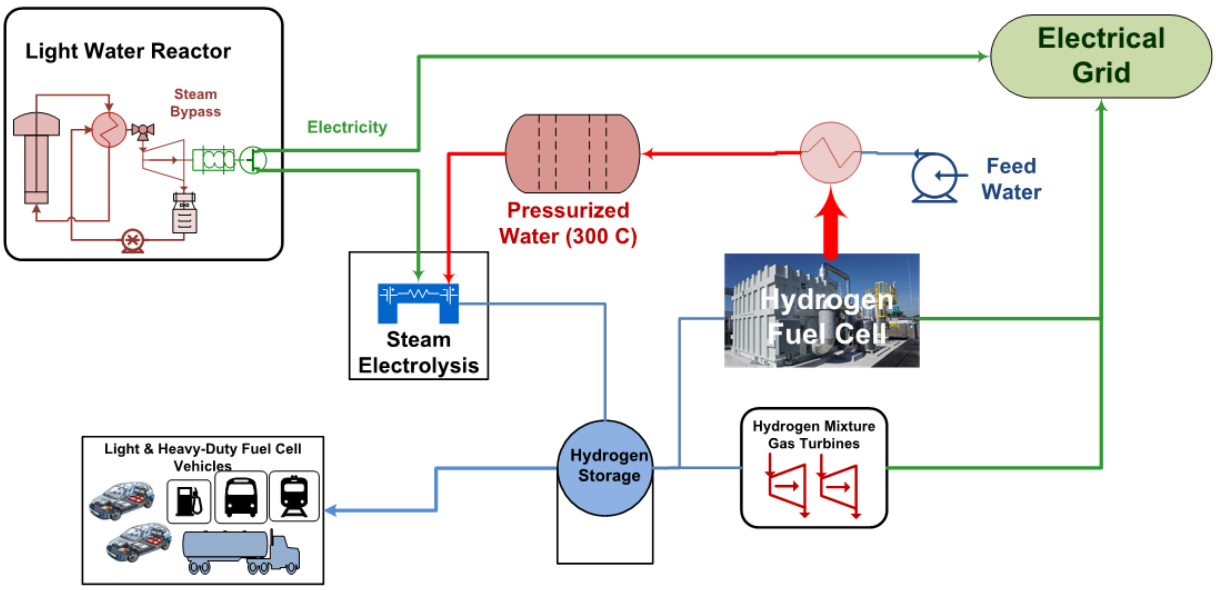

Figure 4-16. Electricity power arbitrage example with hydrogen production and storage.

A case study was completed by INL to compare and rank energy storage technologies that can store energy from an LWR for a wide spectrum of storage durations [20]. In this analysis, 500 MWe-AC of discharge capacity was chosen as the capacity by which all of the energy storage options are compared. Options that were evaluated include

- Utility-Scale Lithium-ion Batteries
  - Lithium iron phosphate (LFP) and
  - Nickel molybdenum cobalt (NMC)
- Power-to-Hydrogen-to-Power
  - HTSE + H_2 Combustion Turbine
  - Reversible Solid Oxide Cells (rSOC)
  - HTSE + Solid Oxide Fuel Cells
- Thermal Energy Storage
  - Electro-Thermal Energy Storage (ETES)
  - Liquid-Based Sensible Heat Thermal Energy Storage (SH-TES).

Batteries are arguably the simplest means of grid-scale energy storage. In Figure 4-17 Alternating-Current (AC) electricity from the power plant may be rectified to DC power and stored in the battery during periods of low demand. Later, when the demand for electricity increases, the batteries release DC electricity, which is inverted to AC power and put on the grid. There are, of course, some losses associated with the rectification and conversion of the electrical power, as well as the step-up/step-down transformers. Each stage was assumed to have a 99% efficiency, resulting in a 4% loss on top of the ~86% DC-DC round-trip efficiency of the battery itself.

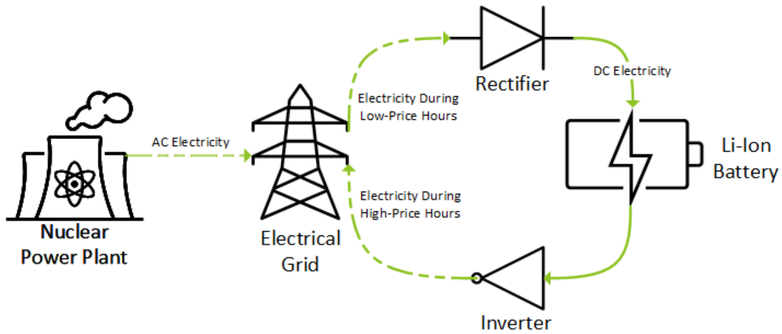

Figure 4-17. Lithium-ion battery energy storage schematic.

As an alternative to battery storage, three hydrogen energy storage technologies coupled with nuclear power were investigated. When the price of energy is low, electricity and heat from the NPP can be diverted to produce hydrogen via HTSE, which is compressed and stored in gaseous tube trailers. Later, when the price of energy rebounds, the stored hydrogen could be consumed in a combustion turbine, fuel cell, or reversible solid oxide cell to produce electricity to put back on the grid.

As with natural gas, hydrogen can be combusted to drive a power cycle. For an energy arbitrage application, it was determined that a recuperated simple cycle combustion turbine is preferred to support demand-response and load-following applications. Figure 4-18 depicts how hydrogen can be used for energy arbitrage using a hydrogen combustion turbine to generate electricity during times of high demand.

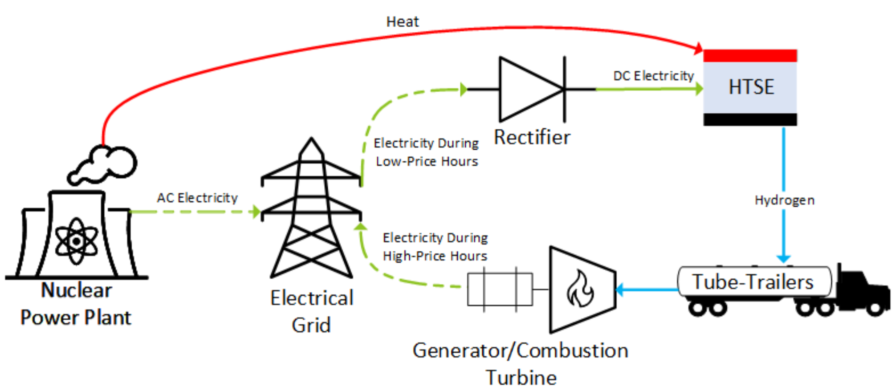

Figure 4-18. HTSE with combustion turbine schematic.

Figure 4-19 displays the LCOH for a 500 MW-e DC HTSE system that is operated from 2–24 hours per day, broken down to illustrate the contribution to the LCOH from initial capital investment, replacement of electrolysis stacks, and fixed and variable O&M. The LCOH is minimized by maximizing utilization of the initial investment and fixed O&M. Although increased utilization requires more frequent stack replacement, this makes up a small contribution to the LCOH even at high utilization. Variable O&M contributes $1.30/kg to the LCOH for all case studies.

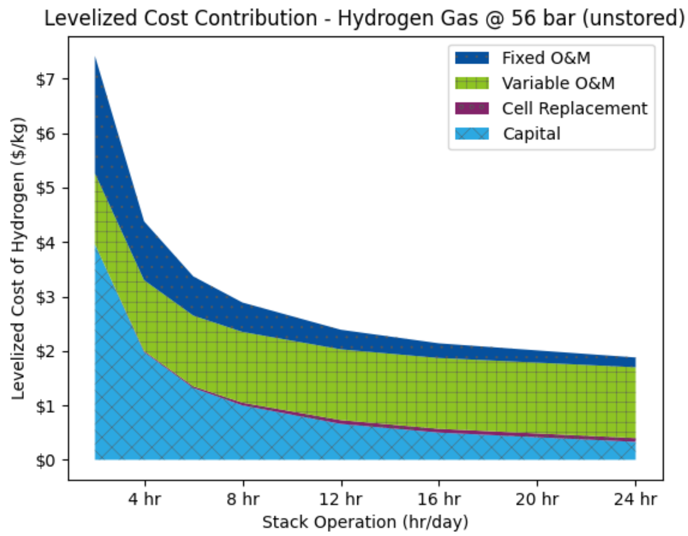

Figure 4-19. LCOH breakdown for 500 MWe HTSE producing un-stored H_2 gas at 56.28 bar and 20°C.

It is worth noting that, unlike an HTSE plant designed to produce H_2 as a product for industry, an energy arbitrage HTSE system is not intended to operate constantly. This can lead to an economic disadvantage due to the low-capacity factor and low capital utilization in some operating schemes. The maximum feasible capacity factor depends heavily on the method used to regenerate electricity from hydrogen. Reversible solid oxide cell (rSOC) systems operate at higher voltage in electrolysis mode than in fuel cell mode, so hydrogen production in electrolysis mode is 3–4 times faster at producing electricity than hydrogen consumption in fuel cell mode. As such, an rSOC system can only produce hydrogen for 5–6 hours per day to allow sufficient time for the rSOC system to consume the hydrogen in a 24-hour period. Alternatively, an HTSE plant can operate for 12 hours if additional fuel cells are installed to increase the rate that hydrogen can be consumed to produce more power. Conversely, a turbo-mechanical power cycle, such as a combustion turbine, can be used to produce power from hydrogen. Single-stage turbines have significantly lower capital costs than fuel cells, but they have lower efficiencies and only convert one-third to one-half of the chemical energy in the hydrogen bonds into electricity.

This study considered two types of thermal energy storage (TES) technologies: (1) electro-thermal energy storage (ETES) and (2) SH-TES. Process configurations and critical inputs for estimating LCOS are demonstrated for ETES and SH-TES. Free-flowing sand is used as the transfer heat fluid in the ETES system.

ETES can use electricity from an NPP to run a supercritical carbon dioxide heat pump during the charge cycle. During the discharge cycle, 500 MWe of electricity is generated by a supercritical carbon dioxide Brayton cycle between hot particle storage and the cold storage vessels.

SH-TES uses molten salt or synthetic oils as the storage media to exchange heat between the heat exchanger and the reservoir (i.e., hot and cold tank). Molten salts absorb heat directly from the heat exchanger and store the energy in the reservoir during the charging cycle; this heat is later released through the exchanger during the discharging cycle to generate 500 MW-e of electricity.

Figure 4-20 displays the levelized cost of storage (LCOS) for two lithium-ion battery chemistries, three hydrogen systems, and two TES systems for durations up to one week, The inset focuses on daily storage. This effort found that generally the LCOS decreases as the storage duration increases to achieve improved utilization of the capital investment. Hydrogen and thermal systems tend to stay relatively affordable as the storage duration increases because cost of additional thermal storage is small compared to the cost of the overall system. Conversely, the LCOS increases for long-duration storage lithium-ion batteries because it requires purchasing more storage blocks, which means a significant increase to the overnight cost of the project.

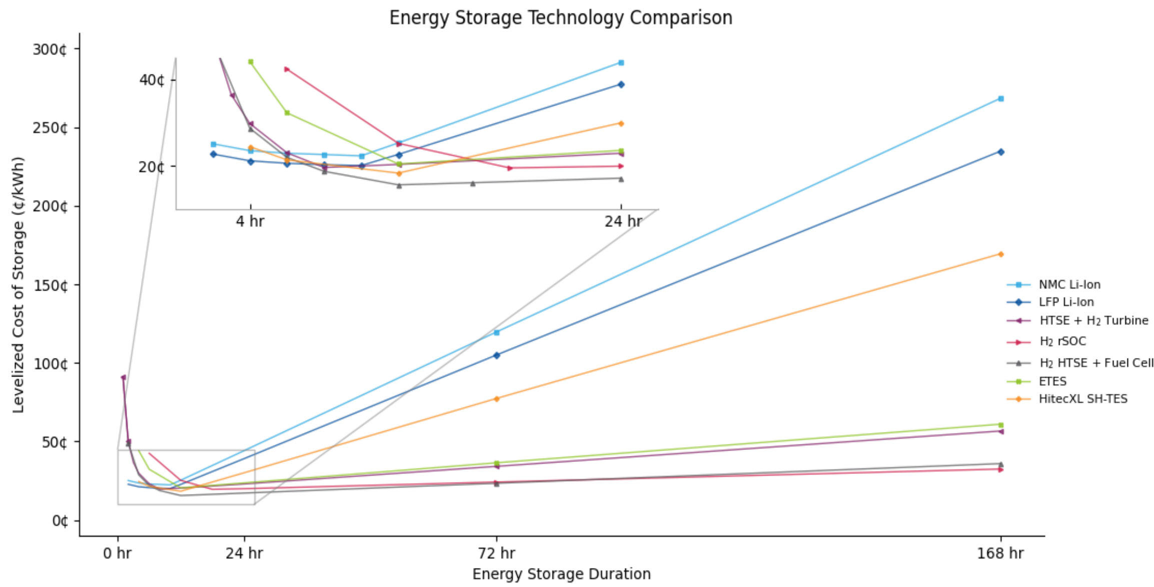

Figure 4-20. Comparison of LCOS for different energy storage technologies [20].

The following is a summary of the high-level conclusions of the technology comparison.

- NMC and LFP Li-ion batteries have the lowest LCOS from 0 to 6 hours of energy storage duration. The battery systems dominate the LCOS even up to 10 hours, except for the H_2 fuel cell.
- The H_2 fuel cell has the lowest LCOS for long-term energy storage duration from about 7 hours up.
- SH-TES performs better than all other technologies except the H_2 fuel cell from about 9–15 hours of energy storage durations. The H_2 rSOC has the lowest LCOS from 16 hours upward, except for the H_2 fuel cell.
- For any storage duration longer than the optimal value for a given technology, the power equipment (e.g., rectifiers/inverters and transformers, fuel cells, turbines, and other equipment whose price can be defined in $/kW-e) utilization plateaus as the number of possible charge/discharge cycles reduces proportionally to the length of the cycle.
- Longer duration storage requires more storage equipment, including individual battery cells, storage tanks, sensible heat storage media, and hydrogen tube trailers, whose price is defined in $/kWh-e. This raises the total capital investment required for the project and, therefore, the LCOS, as the same total amount of energy can be discharged.
- Lithium-ion battery storage systems, which offer the most cost-effective form of grid-scale energy storage for durations shorter than 6 hours, require more batteries to be purchased to facilitate long-duration storage. This results in the technology scaling poorly for durations longer than 10–12 hours.

4.4 Prospector Database

A Hydrogen Prospector tool is currently being developed to analyze hydrogen production integration opportunities with existing nuclear plants. This new tool will improve the understanding of the current energy infrastructure around existing U.S. LWR NPPs and provide insight on potential growth opportunities. The Hydrogen Prospector tool will provide a streamlined user interface for utilities to evaluate the technical economic potential based on existing and potential future hydrogen demand surrounding existing reactors for hydrogen production integration with the existing fleet of LWR nuclear reactors. Relevant data regarding energy infrastructure (e.g., location, volume, purity, and costs of transportation of various carbon feedstocks) has been gathered, compiled, and integrated into a database that will be linked to the Hydrogen Prospector tool.

The framework of the tool has been designed to allow for future additional functionality to evaluate opportunities for LWRs beyond hydrogen production such as integration with nearby industry to provide clean heat and electricity. In terms of supplying hydrogen, the tool provides estimates for type of industry, potential hydrogen demand (MT/day), and the location so that hydrogen transporting costs can be included. The tool is expected to be an interactive application with maps, tables, and graphics for exploring investment scenarios and policy environments, complementing reports and building confidence in new technologies for private sector partners.

5. CONCEPTUAL DESIGN CONSIDERATIONS

5.1 Integrated Nuclear-HTSE System Overview

Integration of an HTSE system with an NPP requires the selection of the most appropriate location for the hydrogen production system and the modifications necessary to supply electrical power and thermal energy (steam) from the plant steam turbine system. A comprehensive assessment for a generalized conceptual design has been developed and is presented in "Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100–500 MWe HTSE Plants" and [1,21]. The following sections summarize the evaluations and key topics required for a utility to consider in the development of an ISP.

Presently, the ISP development is based on a nominal 500 MWe HTSE system design. The conceptual design analyses [1,21] demonstrate that this scale system can be integrated at a PWR nuclear plant with modifications to the plant main steam and electrical distribution systems without negatively impacting plant safety and without significant redesign. The general configuration is shown in Figure 5-1. A similar analysis is in progress for a BWR. A conceptual site plan showing the interface between the HTEF and the NPP is shown in Figure 5-2.

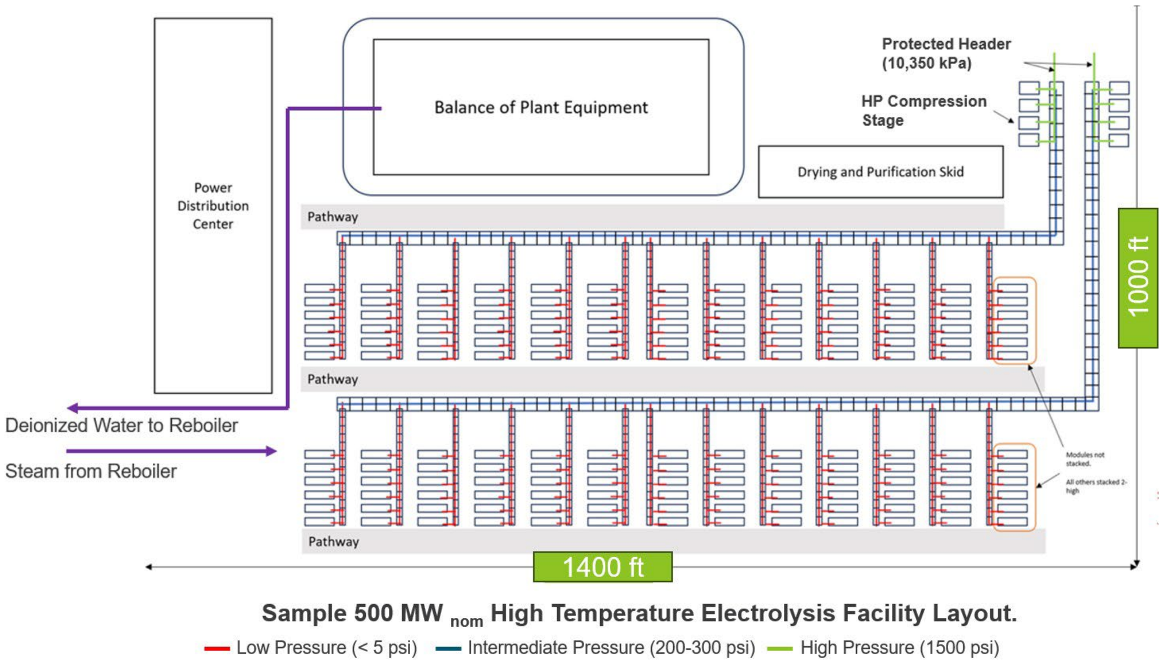

Figure 5-1. General configuration, 500 MWe HTSE.

A 500 MWe integrated system requires approximately 105 MW of thermal power from the plant main steam line (approximately 3% of the total steam flow). The extracted steam (from the cold reheat piping) is directed to a heat exchanger (reboiler) located adjacent to the turbine building that produces clean steam from a de-ionized process flow. The process steam is subsequently piped to the HTEF located outside of the plant's protected area. An electrical connection from the switchyard to the HTEF provides sufficient power to the 500 MWe HTSE and approximately 50 MWe for the BOP equipment of the hydrogen production system. Process hydrogen is compressed and delivered to storage or may serve as an alternative energy system using the hydrogen as a feedstock.

In addition to evaluating thermal power extraction for hydrogen production, the FPOG Pathway has evaluated larger amounts of thermal extraction to support other industrial processes. The analyses presented in "Evaluation of the Technical Feasibility, Plant Physical Modification, and Digital Controls Modifications required for 50% and 70% Thermal Energy Extraction from a Pressurized Water Reactor" [2] provide an initial assessment for thermal extraction systems for energy processes that require a large fraction of the nuclear plant thermal output—upwards of 50% of rated thermal output. Thermal power extraction up to 50% of the rated reactor power is considered achievable per the feasibility analyses performed to date, but more rigorous plant-specific assessments are needed.

5.2 Thermal Power Extraction and Mechanical Design

The initial development of a utility ISP must consider the design options for thermal power extraction. Plant steam to supply the HTSE system heat exchanger (reboiler) can be derived from existing steam system processes for nuclear plants that include such design provisions. For instance, plants with auxiliary steam systems or multi-unit NPPs that share an auxiliary steam system that is used for radiological gas and liquid waste control, gland sealing for the main turbine, etc. may have sufficient capacity to support an integrated HTSE system. Otherwise, extraction from the plant's main steam system or turbine system is required.

An analysis has been completed for the extraction of steam from the cross-under (cold reheat) piping between the high-pressure turbine (HPT) and the moisture separator reheaters (MSRs) for a reference plant design [1]. The analysis concluded that extraction should be taken from two cross-under lines, one on each side of the HPT, to avoid turbine imbalances. This preferred location provides sufficient thermal energy to process deionized water to the targeted steam conditions while minimizing the impact to both station efficiency and transient operation if steam flow to the HTEF is isolated (i.e., loss of supply steam to the HTEF). Steam extraction at this location also reduces the steam supply temperature experienced by the reboiler, limiting necessary design considerations for the reboiler.

The utility ISP should identify all options for thermal power extraction capable of providing the required steam demand. Steam delivered to the reboiler is required to be at least 150°C (302°F) and 50 pounds per square inch gauge (psig). Plant-specific secondary system thermodynamic performance analyses (e.g., PEPSE model) are required to determine the options for extraction sufficient to supply the HTSE system and BOP and to return the condensate back to the condenser. Hydraulic analysis is required to establish pipe sizing and required auxiliary equipment to supply the reboiler. For purposes of evaluating the generic conceptual design, minor additional thermal extraction is needed to cover various thermal losses, inefficiencies, and design margins typically associated with the sizing of piping, pumps, heat exchangers, valves, etc. The evaluation effort must also consider the potential for new plant hazards such as high energy line breaks (HELB). In this case, based on the analysis results for the steam extraction system, the new extraction line may exceed the threshold for HELB classification based on temperature and/or pressure and design provision provided to protect the plant.

5.3 Impact on Core Reactivity

The modifications to the plant to extract thermal energy presented in Section 5.2 affect changes in the energy balance between the PWR primary system and the steam turbine. This results in an impact on core reactivity associated with extracting steam from the secondary cycle and must be assessed. As noted previously, the development of a utility ISP is based on the integration of a 500 MWe HTSE system and evaluations demonstrate that the extraction results in a 2.8% reduction in secondary mass flow (this reduction in flow represents the total change to the MSR in both trains). At this level, normal operation reactivity impacts are anticipated to be minimal. However, the development of the plant-specific ISP requires analysis to quantify these effects and to consider the reactivity effects associated with (upset) conditions such as those associated with sudden HTEF steam flow perturbations. An assessment must verify that the impact from such conditions shall not exceed the capabilities of the normal NPP control system response.

5.4 Electrical Design

Similar to the requirements for evaluation of thermal extraction presented Section 5.2, the utility ISP preparation needs to establish options to provide electric power to the HTSE and the BOP equipment located at the HTEF. For the nominal design considered here, the HTEF requires 500 MWe power for the electrolysis process and approximately 50 MWe for auxiliary loads. Using a power factor of 0.92 for HTEF processes, the total power required for the HTEF is 600 MVA.

The conceptual analyses presented in “Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100–500 MWe HTSE Plants” [1] and “Pre-Conceptual Design for Large-Scale Nuclear Integrated Hydrogen Production Facility” [21] assumed the HTEF would be located approximately 0.5 km from the nuclear plant and that power will be supplied from the plant via a 345-kV transmission line tie-in point, which is the high-voltage side of the NPP’s main generator step-up (GSU) transformer. The power system supply design will require the necessary equipment for isolation, line protection, and maintenance. The power system design also includes placement of new revenue meters.

An electrical transient analyzer program (ETAP) electrical power system model is required to evaluate the power flow and short circuit impacts of the HTEF electrical tie-in and includes the typical electrical parameters for an NPP main power circuit. The ETAP analysis performed for the reference plant shows that the additional loads, which principally consist of the rectifiers that supply DC to the electrolyzers, have a negligible impact on existing NPP equipment. An electrical transient analysis is also required to evaluate the impacts of a trip of the hydrogen plant load on the existing NPP generator. Analysis for the reference design showed that the plant generator remains stable for both faulted and unfaulted trips of the HTEF.

The ISP must also ensure that the site-specific conceptual electrical design assessment verifies that modifications to the electrical system must be in compliance with North American Electric Reliability Corporation (NERC) reliability standards. This applies since the high-voltage transmission line supplying the HTEF is connected to a radial system with a generator that has a gross individual nameplate rating that exceeds the power and voltage threshold for a bulk energy system. Additional details are presented in "Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100–500 MWe HTSE Plants" [1] and "Pre-Conceptual Design for Large-Scale Nuclear Integrated Hydrogen Production Facility" [21].

5.5 Integrated System HTEF Design Assessment

The HTEF consists of the HTSE, hydrogen processing facilities (BOP), and all required infrastructure to produce and distribute the product hydrogen. The analysis for the referenced PWR plant provides details for the facility design and process requirements [1,21].

The HTEF is expected to be located outside of the protected area but inside the owner-controlled area to provide sufficient separation distance between the hydrogen and important safety-related systems, structures, and components (SSCs). The conceptual 500 MW designs in [1,21] consider separation distances of 250 m and 500 m between the PWR and HTEF to be sufficient. The product hydrogen is transported a safe distance away (e.g., 1+ km) for high-pressure compression and storage. Figure 5-2 presents the general site layout for the conceptual plant. The plant-specific layout that will be developed for the ISP will consider options that minimize plant modifications and impacts and the consequential hazards to safety-significant SSCs (see Section 6.3), and that approach will ultimately minimize the cost of implementation.

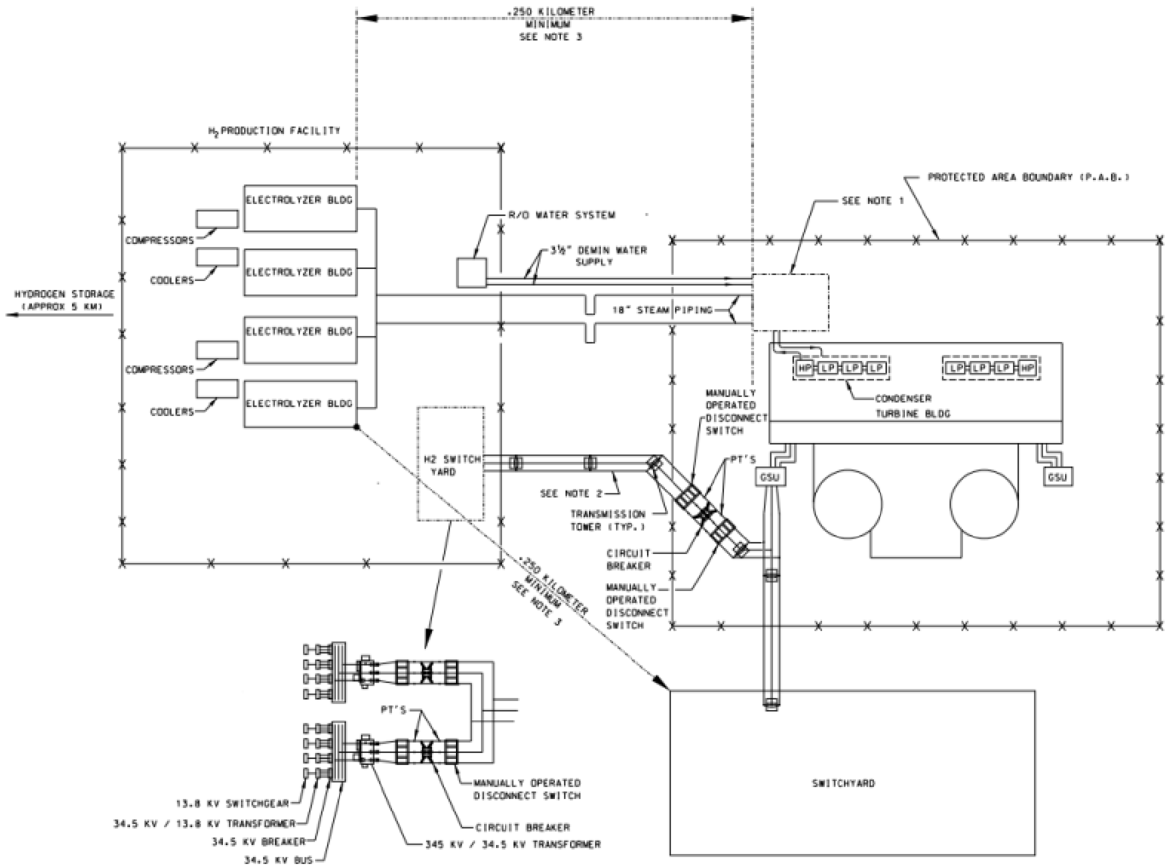

Figure 5-2. General site layout for a 500 MWe HTEF.

The NPP and HTEF design scopes are delineated at the boundaries of the hydrogen facility and high-voltage switchyard for the mechanical and electrical connections. This cut-off is expected to allow the hydrogen facility and switchyard designs to be largely isolated from nuclear regulatory requirements, which are more stringent and add cost throughout the duration of engineering, design, and construction.

The product hydrogen exits the electrolyzers at high-temperature, low-pressure, and with high water content (approximately 15% molar fraction of water). Heat transfer, compression, and drying/purification are needed to reach the desired conditions for offtake. Downstream of high-pressure compression, hydrogen will be sent offsite via a pipeline to the desired user(s). Alternate offtakes include a pipeline for natural gas blending, onsite truck filling station, or onsite storage. Detailed design considerations associated with offtake are not developed in this design report but will be needed for any site considering large-scale hydrogen production. The utility should assess as part of the development of the ISP whether the product oxygen will be used or vented or provisions included for its use at a later time. Oxygen venting will require environmental permitting and approval.

The SOECs require an external supply of hydrogen for startup, shutdown, and idle conditions. This hydrogen can be sourced from the post-processed hydrogen product (via onsite storage or vehicular transport) or from a hydrogen pipeline offtake. It is assumed that the hydrogen pipeline used for product offtake could also be used for startup and shutdown. During hot idle conditions, dried hydrogen located in the hydrogen buffer vessel downstream of the dehydration system could be used. Given these sources of hydrogen, there is limited need for onsite hydrogen storage. External hydrogen supply conditions for selected projects would be stipulated by the electrolyzer vendor selected.

During the development of the ISP, the utility should assess the final hydrogen pressure delivery requirements and the appropriate design for the compression system. Typically, a two-stage design will be developed with a low-pressure compression stage that will receive hydrogen from the production system and deliver the gas to the purification and dehydration system at approximately 30 bar. The hydrogen is purified, dried, and then directed to a HP compressor to satisfy the product quality and delivery requirements.

The following functions will need to be considered in the development of the ISP for the plant-specific HTEF design:

- Water treatment and supply is needed to produce purified (deionized) water to meet the quality requirements for electrolysis.
- Water treatment waste processing is required for solids removal and disposal and for processing of all wastewater streams. The site National Pollutant Discharge Elimination System (NPDES) permit may require revision to account for the additional wastewater flows and any water quality impacts.
- A cooling water supply with heat rejection (e.g., evaporative cooling towers) will be required for cooling of some equipment, such as the hydrogen rectifiers, compressors and dehydration system.
- A new fire protection system, including pumps, a main header loop, hydrants, and building fire systems, will be designed in accordance with NFPA 850. A risk analysis per NFPA 850 is required. Additionally, per NFPA 2, “Hydrogen Technologies Code,” minimum setback distances from bulk gaseous storage systems (hydrogen storage modules) will be followed, and firewalls will be included to further separate these systems from other equipment in the plant, as required.
- The new hydrogen facility will require instrument air for control valves, emergency shutoff valves, and other equipment. The hydrogen electrolyzers use instrument air system for pneumatic valves. The instrument air system shall include compressor(s), dryer(s), a wet air receiver, an instrument air receiver tank, and instrument air piping. The new hydrogen facility will require nitrogen for purging hydrogen systems.
- Condensate generated from the steam supply, SOECs, compression cooling, and purification/drying skid are combined and sent to a condensate recovery sump. The condensate is then sent to the water treatment clear well for further processing. This will help to reduce wastewater and raw water makeup flows.

5.6 Instrumentation and Control Systems

The NPP control room operators will operate and monitor the HTSE production system and BOP. A hydrogen interface control panel located in the Main Control Room will provide operational control of the mechanical and electrical equipment that dispatches steam and power to the HTEF. Control room indication and control will facilitate HTSE system start up, steam supply, and electrical power to the HTEF. A dedicated set of operator controls with remote human-machine interface (HMI) will be provided. The HMI will allow for control, indication, and alarm of the hydrogen power line and steam supply. These controls will be electrically and functionally isolated from NPP controls, but the remote HMI will be collocated in the NPP Main Control Room. Additional indication and controls will be provided locally to the HSS equipment. The operator should be trained in operating the power and steam supplies from the NPP to the HTEF using the new standalone HMI. Section 9 provides a summary of the INL research efforts to develop a prototype HMI to provide a graphical user interface for operators to monitor and control the HES and HTEF operation.

5.7 Nuclear Power Uprate

The market opportunity for NPP power uprates and hydrogen cogeneration is emerging. NPPs have performed power uprates since the 1970s as a cost-effective option to generate increased power. Most of the currently operating U.S. nuclear plants have performed some type of power uprate. As a result, the process and typical impact of power uprate on plant SSCs is well understood. This report identifies that there is still a significant amount of untapped power available by uprating existing NPPs and providing reference data for which SSCs are likely to be impacted by power uprate. This report estimates that there is roughly ~5.500 MWt of untapped power in the current operating BWR fleet and ~13,000 MWt of untapped power in the current pressurized water reactor (PWR) fleet.

These uprates were completed via the following paths:

- MUR (Measurement Uncertainty Recapture Power Uprate): The power uprate is up to 2% and is also often referred to as 10 CFR 50.62, Appendix K, uprates. The uprate accounts for uncertainty in measuring feedwater flow. MURs typically do not require significant component upgrades other than new feedwater flow measurement devices.
- SPU (Stretched Power Uprate): Power uprate that increases power levels between 2% and 7% is within the existing design margin of the plant. SPUs typically require changes to instrument setpoints but generally do not involve significant plant modifications beyond the HPT (and in some cases the main generator), depending on the existing margin.
- EPU (Extended Power Uprate): Uprates with power increases greater than SPUs. EPUs typically require significant modifications to the BOP equipment such as HPT, condensate pumps and motors, main generators, and transformers.

Unlike power uprate, hydrogen cogeneration with a NPP is a relatively new concept with initial pilot efforts underway and can be coordinated with power uprate of an NPP. However, there is growing interest in the production and use of zero-carbon hydrogen for hydrogen-intensive processes and as an alternative energy carrier to displace fossil fuels and for applications that cannot be easily electrified or decarbonized and to provide a cost-effective approach for bulk long-term energy storage. While this zero-carbon hydrogen market is still emerging, the current outlook is favorable with potential for clean hydrogen demand.

NPP power uprate and potential cogeneration of hydrogen are expensive investments. The IRA was enacted by Congress in 2022 to promote investment in new, carbon-free power generation and sustainable operation of existing carbon-free assets. Specifically, the IRA includes both a PTC (Section 45Y of the IRA) and an investment tax credit (ITC–Section 48E), which utilities may leverage to offset the costs of power uprate. Further, the IRA includes a provision (Section 45V) for a PTC associated with carbon-free hydrogen cogeneration. These tax credits, along with recent legislation efforts to decarbonize the country, have reemphasized the importance of maintaining and optimizing the existing nuclear plant operating fleet. As a result, utilities are reexamining the possibility of uprating their existing nuclear assets to further maximize carbon-free electricity generation.

The historical uprates relied mostly on the already available safety margins to demonstrate that plant modifications due to power uprates do not affect the overall plant safety. For plants considering uprating their facilities, the safety margins need to be assessed. However, latest developments and advancements in computational resources and technologies, including modern data analytics technologies, such as artificial intelligence and machine learning, dramatically improve modeling and simulations of plant operations and underlying physics-based processes for these safety assessments. This results in a better understanding and representation of scenarios that may occur at an NPP. The more detailed modeling and simulations of NPP scenarios remove unnecessary conservative constraints typically imbedded in most of the analyses and demonstrate improved (i.e., larger) safety margins directly supporting larger power uprates.

Ultimately, operating NPPs have an unprecedented opportunity to increase and diversify their revenue through incentives created by the IRA. This opportunity, coupled with substantial technological advancements in hydrogen generation using electrolysis, further warrants the need to evaluate clean hydrogen cogeneration. While financially important for individual utilities, this opportunity is imperative to national goals for decarbonizing energy sectors while making the sector more resilient and independent. This is especially true considering that power uprates can be achieved in the very near term, well before new reactors are fully developed, deployed, and connected to the grid.

6. INTEGRATED SYSTEM SITING GUIDANCE

6.1 General Siting Considerations

The placement of the HTEF is determined first and foremost by the safety of the NPP and the public. Other considerations, as outlined in Section 5, are made due to the geographical properties of the existing NPP site, the proximity to the HES heat exchanger (reboiler) building to make the steam supply line as efficient as possible, the accessibility of the HTEF for distribution or transport of the hydrogen product, and efficient routing of the electrical supply lines and equipment placement to power the HTEF. The hazards associated with the siting of an integrated SOEC hydrogen production facility at a nuclear plant must be evaluated to ensure that existing safety-related and important SSCs are not adversely affected as the result of any new failure mode or changes to existing failure modes. Siting considerations for the HTEF follow based on general design requirements and consideration of the potential impacts to the site safety equipment that will be evaluated in the hazards analysis (Section 6.3), including the standoff distances to account for overpressure hazards in the HTEF.

A utility siting study should begin by considering the conceptual integrated system design documented in [1,21]. A utility-specific analysis should adopt a similar process by establishing potential location sites that provide sufficient area for the HTEF. A site analysis is performed to understand what features should be considered for each prospective location. Features that were determined as part of the conceptual design analysis and which would be considered for a site-specific assessment include population centers, transmission line paths, public service structures (e.g., water towers and gasoline stations), and natural geographic features (e.g., hills, lakes, and wetlands).

The concern for hydrogen detonation and pressure wave impact on adjacent structures has been addressed using the methods prescribed by NRC RG 1.91 [22]. The TNT equivalence method prescribed in this Regulatory Guide is intended for nearby facilities and transportation routes to the NPP. All safety-related SSCs would have to experience a peak positive incident overpressure of no more than 1 psi. The safe distances for no more than 1 psi are correspondingly lower. An example of a placement of an HTEF based on three potential site options is shown in Figure 6-1 and illustrates the low, medium, and high-pressure exclusion boundaries (safe distances) and NFPA standoff distances relative to safety-related SSCs and important functions, including spent fuel cask storage, security and safety boundaries, power plant switchyard, and the connected transmission lines. Recent interaction with the NRC has disclosed that facilities within the exclusion area of the NPP, as portrayed in Figure 6-1, will not use NRC RG 1.91 but will be sited as part of the site's fire protection plan, which uses NFPA 55. NFPA 55 uses a most-probable leakage rate to determine the mass of H_2 available for detonation and provides a table of results for a safe standoff distance. NRC RG 1.91 still applies for facilities outside of the NPP exclusion area. Both standoff distance methodologies are based on the same detonation overpressure calculations corresponding to a full guillotine break of the hydrogen production piping, which provides more mass for detonation in the resulting plume.

Figure 6-1. NRC RG-1.91 [22] example analysis for a 500 MW_{nom} HTEF site (note that NFPA 55 distances as part of the fire protection plan will be slightly less).

6.2 Interface Requirements

Section 6.1 describes the primary considerations for siting an HTEF based on plant and public safety. Suitable siting locations must also facilitate the interface with the HES for HTSE steam and condensate recovery, electrical power supply, monitoring and control capability, cooling water and waste treatment, service gas supply, and other interface requirements for the HTSE and hydrogen processing BOP that have been described for the conceptual design in Section 5. The utility-specific ISP should evaluate siting options that satisfy the safety requirements and configure the design to optimize the interface with the plant systems. Consideration should be given for personnel and Operations access, site egress, plant security, and hydrogen distribution and facilities for transportation.

6.3 Hazards Analysis and FMEA

The ISP will require a hazards analysis to identify and evaluate all potential adverse impacts on plant equipment resulting from a failure of the HES and the NPP co-located HTEF. These analyses will be based on a plant-specific conceptual design for the placement and integration of the HTEF in consideration of design guidance summarized in Section 5 and in consideration of the siting assessments and interface requirements defined in Sections 6.1 and 6.2, respectively.

The ISP development will require that the potential hazards introduced by the co-location of the HTEF and all attentive equipment will be evaluated for impacts to the original design and licensing bases and the associated SSCs. This hazards analysis provides input for the deterministic and PRA required to demonstrate that plant modifications do not degrade plant safety. This process is thoroughly defined in "Expansion of Hazards and Probabilistic Risk Assessments of a Light-Water Reactor Coupled with Electrolysis Hydrogen Production Plants" [23].

The assessment of hazards introduced by the plant-specific conceptual design should be completed by a group utility and industry subject matter expert (SME) and will culminate in the development of a system-level Failure Modes and Affects Analysis (FMEA). The FMEA is required to determine the hazards presented to the NPP, the hazards presented to the operation of the HTEF, and to assess public safety and perception. Information on the technical resources and appropriate SMEs used for a conceptual design in preparation of the hazards assessment and FMEA are documented in "Expansion of Hazards and Probabilistic Risk Assessments of a Light-Water Reactor Coupled with Electrolysis Hydrogen Production Plants" [23] and should be used to inform the development of the plant-specific ISP.

Based on the example performed for a conceptual integrated HTEF design [23], a plant-specific hazards evaluation for the plant-specific conceptual design and the specific configuration for the integrated HTEF will be required. Information assembled by the SMEs will determine the external events that could affect the NPP and is expected to include examination of external overpressure (hydrogen detonation) events, thermal and electrical load effects on the NPP (load-drop feeding back negative reactivity into the NPP causing a reactor trip), steam leakage at the HTEF, and unique risks for BWRs and PWRs. The impact of these events will be evaluated for safety critical structures, including the reactor containment; borated, condensate, and other water storage tanks; the electrical switchyard; and others that are essential to shut down and maintain the reactor in a safe condition. The assessment will also require consideration of other structures that affect operations, but which are not typically needed to be able to safely shut down the reactor. Typical production related SSCs that should be considered include circulating water and standby service water pump houses, demineralized water storage tank(s), cooling towers, well water pump houses, liquid nitrogen tanks, and hydrogen and nitrogen gas tanks.

The analyses for the conceptual design defined in Section 5 identified potential hazards resulting from the addition of the HES and locating the HTEF at a calculated safe distance. These include a hydrogen detonation at the HTEF that causes an overpressure event at the NPP site, an unisolable steam pipe leak in the HES outside of the NPP main steam isolation valves (MSIVs), a reboiler leak in the HES either causing an unisolable steam leak or contaminating the customer HTEF steam loop, and the prompt loss of thermal load to the HES. FMEAs rank risk-informed hazards to prioritize what hazards to mitigate first. They also identify where specific hazards fit within the plant's PRA event trees or if a new event tree needs to be created. The FMEAs performed by the utility should be used, when appropriate, to redesign or improve upon the initial conceptual proposed designs.

A fire risk analysis is also required per NFPA 850. Additionally, NFPA 2, "Hydrogen Technologies Code," specifies minimum setback distances from bulk gaseous storage systems (hydrogen storage modules) that will be followed, and firewalls will be included to further separate these systems from other equipment in the plant, as required.

7. PROBABILISTIC RISK ASSESSMENT

A utility that elects to formally evaluate an integrated HTEF at a nuclear facility will be required to demonstrate that the proposed change will not adversely affect plant safety. Proposed modifications to the LWR design and operation must be approved by the U.S. NRC. A PRA is used to risk-inform the decision for change acceptance by the NRC.

The PRA process numerically estimates the risk associated with a plant change by computing the probabilities of what can go wrong and the consequences of those undesired events. The quantitative PRA results are compared to NRC guidelines, which determine whether the design and operation are sufficiently safe for approval or if changes need to be made to maintain plant safety.

The ISP will include the required PRA analysis based on the approach defined in [23]. The hazards assessment and FMEA prepared for a set of generic plant integration conceptual designs established risk information that was subsequently evaluated in a PRA. Those events not screened by an engineering evaluation were mapped into the respective event trees, and the initiating event (IE) frequency for these event trees are re-quantified for BWR and PWR PRA models based on the increased frequency of occurrence caused by the addition of the HES and the HTEF at a calculated safe distance from critical SSCs. The required modifications for an HTEF in the generic conceptual cases were shown to affect the design bases accident (DBA) IE frequencies and the core damage frequency (CDF) contribution of main steam line break, switchyard-related loss of offsite power (LOOP), and general transient. The results for these generic cases demonstrate that the overall PWR CDF for a 500 MW HES increased minimally and showed even smaller changes for the BWR case.

Utility-specific PRA based on the same approach are dependent on the specific site layout. Consequently, the process developed for the hazards assessment, FMEA, and PRA will be required for the ISP and performed as part of the site-specific conceptual design and layout. The process will support the optimization of the design that ultimately demonstrates an acceptable level of risk and one that provides for an acceptable licensing assessment.

8. LICENSING

A utility ISP will require the development of a licensing strategy to process and implement changes to the NPP in accordance with federal regulations. The utility may elect to evaluate the changes under 10 CFR 50.59. The Domestic Licensing of Production and Utilization Facilities part in 10 CFR 50 establishes the conditions under which licensees may make changes to the facility (NPP) or to procedures and conduct tests or experiments without prior NRC approval. A supporting pathway uses RG 1.174 [24] and risk-informed metrics to approve a plant configuration change based on the effect on the overall CDF and (LERF) of an approved PRA. This pathway is dependent on the tail end of the analysis, the CDF and LERF resulting metrics of the PRA. Proposed changes that do not comply with the 10 CFR 50.59 criteria may require NRC approval through the Licensing Amendment Process (via a Licensing Amendment Request [LAR]) as defined in 10 CFR 50.90.

To assist utilities in the evaluation of integrated HTSE, the LWRS FPOG Pathway formed the Hydrogen Regulatory Research Review Group (H3RG) to generically research the magnitude of the high-temperature hydrogen electrolyzer technology addition at the NPP that could potentially be accepted under a 10 CFR 50.59 evaluation. Knowledge of this threshold would help individual licensees understand the significant contributors to that evaluation and help them focus their design evaluations on the most important risk contributors. A summary of the collaborative industry effort is documented in "Report on the Creation and Progress of the Hydrogen Regulatory Research Review Group" [25] and includes a draft 10 CFR 50.59 evaluation that provides a framework to assess the eight criteria of 10 CFR 50.59 (c)(2). The intent of these design and associated regulatory assessments was to determine compatibility in support of the next generation of MW-level nuclear-integrated HTSE demonstration/commercial projects.

The H3RG regulatory program assessments were informed by an effective collaborative effort among INL internal regulatory experts, utility licensing staff, and industry nuclear regulatory consultants. From a high-level summary perspective, the H3RG research findings determined that plants desiring to add nuclear-integrated hydrogen by HTE up to 500 MW of nominal HTSE should be able to justify the plant modification without formal license amendments (LARs) under the 10 CFR 50.59 licensee evaluation process provided that their original licensing basis included consideration of the effects of explosion of hazardous materials (including hydrogen gas) at or near the NPP. These analyses also simplistically evaluated the integration of a 1000 MW HTSE from a hazard standpoint. A thorough evaluation relative to the 10 CFR 50.59 criteria has not been completed. All thermal extraction systems and switchyard modifications can be considered under 10 CFR 50.59.

Hydrogen facilities built outside of the NPP's exclusion area must site the facility a safe distance from the NPP using NRC RG 1.91 and would have no impact on the site's license since the site would not be modified. The exclusion area is defined in 10 CFR 50 as the area that the licensee has the authority to determine all activities, including exclusion or removal of personnel or property.

Hydrogen facilities built within the NPP's exclusion area must site and build the facility as per its fire protection plan. The modification to the site fire protection plan requires a change to the site operating license and would not allow for a 10 CFR 50.59 consideration.

Additional discussion is also planned with the NRC to address potential fire protection-related concerns associated with 10 CFR 50, Appendix R, and the NFPA 805, plants fire protection programs, along with NFPA 55 specific to hydrogen facilities and storage. Production of hydrogen and its distribution and storage must be considered in the licensing assessment. NRC engagement to assess the adequacy of the current fire protection evaluation methods is currently planned, including the potential for the development of an NRC-approved topical report. The proposed effort will establish a rigorous heat flux (fire) and detonation analysis methodology for NRC approval under a topical report to aid licensees engaged in determining allowable siting standoff distances between co-located high-temperature electrolysis facilities (HTEFs) and NPP SSCs important to safety.

Other plant-unique licensing considerations will need to be evaluated and potentially submitted for regulatory approval. The licensing assessment included in a utility-specific ISP must address the following topics:

- Emergency plans
- Security plans
- Independent spent fuel storage facilities
- QA plans
- Control room habitability
- Technical specification language that may conflict with co-locating a nuclear-integrated hydrogen facility in the owner control area
- Compliance with regulations outside the purview of 10 CFR 50.59 (i.e., other federal and state regulations and local ordinances, as applicable).

9. OPERATIONS SUPPORT

Under the FPOG Pathway, INL researchers used a simulator-based approach to develop and evaluate potential thermal power dispatch (TPD) operations. This program serves two key functions towards accelerating industry adoption of TPD capabilities. As no existing TPD capability currently exists in any U.S. commercial NPPs, a concept of operations must first be developed. INL selected representative PWR plant designs and full-scope training simulators to serve as test platforms for developing and evaluating the operations. INL modified the generic pressurized water reactor (GPWR) simulator from GSE Solutions with several TPD models representing different methods for performing thermal power extraction. The models integrate with both plant processes and control systems to accommodate and support dynamic TPD scenario testing. Additionally, INL executed a cooperative research and development agreement (CRADA) with Westinghouse to provide access and expertise with a proprietary full-scope simulator from a currently operating plant (Westinghouse three-loop pressurized water reactor; W3LPWR). Through this collaboration, a vetted and industry-level implementation of the reactor control system was developed to integrate the TPD system into the existing control systems of the NPP. These two simulators serve as platforms to develop the various aspects of TPD operations, including the HMI and operating procedures to manipulate the TPD.

Figure 9-1. INL Human Systems Simulation Laboratory that hosts GSE Solutions' GPWR and Westinghouse's W3LPWR full-scope simulators.

The INL researchers developed a prototype HMI to provide a graphical user interface for operators to monitor and control the system. Additionally, existing procedures were modified to provide transitions to TPD-specific procedures and allow TPD procedures to transition back to existing procedures. This represents integration of TPD operations into the existing plant concept of operations. Both normal and abnormal fault operations were developed to ensure the system can be operated routinely as expected. The normal and abnormal fault operations also support developing expertise to identify and mitigate faults that arise during TPD operations, whether those faults originate in the TPD system or in the original plant. After iterative development of the HMI and procedures, which included operator feedback, the operation of the system was evaluated following an integrated systems verification and validation approach, as outlined in NUREG-0711 [26]. These week-long study workshops used a human-in-the-loop (HITL) testing paradigm in which operators executed normal and fault scenarios in INL's Human Systems Simulation Laboratory (featured in Figure 9-1) [27]. Operators used the full-scope simulator with the prototype TPD HMI and procedures while being observed by an interdisciplinary team. Figure 9-2 shows a screenshot of a prototype TPD HMI that was used during the operator tests. Operator and observer team debriefs were performed after each scenario execution to capture issues and identify improvements to TPD operations.

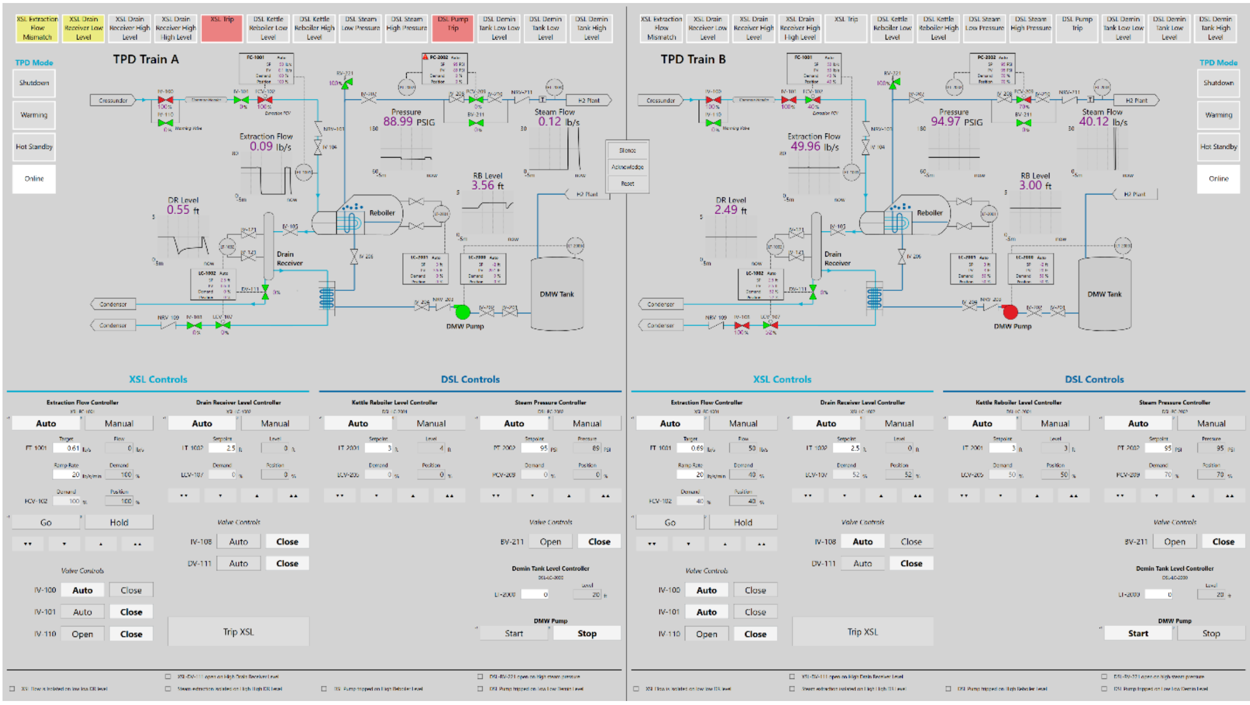

Figure 9-2. Prototype HMI developed for the GPWR full-scope simulator. Several TPD designs have been evaluated. The depicted TPD design is a dual train system.

To meet potential HTSE business case needs, TPD transitions between the maximum and reduced hydrogen production may be needed as often as twice a day. Performing those maneuvers in ten minutes or less could be particularly beneficial. The HITL testing successfully demonstrated this feat is achievable without unduly adding burden to operators. Second, operator responses to TPD and existing plant faults were successfully demonstrated as inducing no additional human error risk across all those tested and scenarios. Each subsequent HITL test aims to reduce the uncertainty for TPD operations towards the goal of providing industry with a template to adapt to their specific implementation. Towards this goal, incremental increases in the fidelity of the full-scope simulators will continue by integrating more representative models. The latest test integrates the full-scope simulator with a dynamic HTSE model to begin to integrate HTSE plant considerations in the overall TPD operations. Future work aims to integrate electric grid models to address how the three entities coordinate during TPD operations.

10. IMPLEMENTATION STRATEGIC PLAN SUMMARY

The following summarizes the key parts for the development of an ISP for hydrogen production at U.S. domestic commercial NPPs. The approach is based on guidance developed from the results of a broad and technically detailed research and testing effort conducted under the DOE LWRS program. The LWRS program supports the DOE mission of providing improved economic value for the existing domestic fleet to ensure that this clean source of generation is maintained as part of a reliable and resilient electric grid. The guidance summarized here is intended to provide NPP owners, electrical power utilities and area balancing authorities, and hydrogen gas suppliers and users with an introduction and access to (1) computation tools that evaluate the business case and investment decisions for producing hydrogen based on individual plant and location-specific conditions, (2) preconceptual architecture/engineering design documents that can be used to guide plant-specific integration with a close-coupled hydrogen plant, (3) information relative to operating concepts that allow the nuclear plants to dispatch electricity steam to a water-splitting electrolysis plant to produce hydrogen, (4) generic safety hazards and risk assessments that are pertinent to evaluating license requirements, and (5) regulatory perspectives and approaches that need to be taken into consideration. The ISP development is proposed in four steps and is presented in the Table 1.

Table 1. Summary of four steps in the ISP.

ISP Development Part 1 – Bases for Integrated Hydrogen with Nuclear Power		
1-1	Initial evaluation of NPP/utility needs i. Service area load forecast ii. Forecast for additional renewable generation iii. Transmission constraints	Initial Utility Feasibility Assessment Section 3 - 4
1-2	Assessment of plant operational flexibility to accommodate variable renewable generation and market conditions	
1-3	Assessment of grid reliability and resiliency – NPP contribution	
ISP Development Part 2 – Business Case Assessment		
2-1	Assess local and regional hydrogen market opportunities, including market size, growth, and competition	Conceptual Business Case and Initial TEA Section 4.3
2-2	Evaluate resource availability and attributes (e.g., existing pipelines with capacity, proximity to industrial user, transportation)	
2-3	Determine infrastructure requirements for production and distribution of hydrogen	
2-4	Evaluate technical options for hydrogen production (electrolysis) and the potential economic benefit of a NPP power uprate to offset the impact of TPE	
2-5	Develop an initial TEA for a pre-design (conceptual) integrated hydrogen system	
ISP Development Part 3 - Evaluation of Integrated Hydrogen Technology with Nuclear Power Plants		
3-1	Technology assessment and selection	NPP Plant Modification Assessment and System Impact Analysis Sections 5 - 8
3-2	Thermal extraction process evaluation and assessment of plant impacts and generation performance	
3-3	Determination and electrical power distribution evaluation	
3-4	Siting assessment with hazards analysis	
3-5	Evaluation of HTSE system operation, control systems modifications, and Operations impacts	
3-6	Evaluation of impacts to the plant PRA	
3-7	Licensing assessment	

ISP Development Part 4 - Evaluation of Project Economic Potential		
4-1	Comprehensive plant conceptual design with project capital and operating cost estimate	Conceptual Integrated Program Cost Estimate and Final TEA Section 4
4-2	Project techno-economic analysis	

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Appendix A

Summary of LWRS FPOG Integrated HTSE Program Documents

<table>
<tr><th>Techno-Economic Assessment Reports and Tools</th><th>Key Outcomes and Significance</th></tr>
<tr><td>Report: INL/RPT-23-73909
August 2023
Estimating the Value of Nuclear-Integrated Hydrogen Production and the Dependency of Electricity and Hydrogen Markets on Natural Gas</td><td>A user-friendly nuclear power plant (NPP)-HTSE H_2 profitability tool developed in Microsoft Excel to help nuclear operating utility companies evaluate the profitability of nuclear-integrated hydrogen production. The tool can perform the following analysis:
• Financial performance
• Sensitivity analysis
• Electricity versus hydrogen production preference analysis
• Profitability analysis using heat maps.
Four example cases were completed to showcase the results and capability of the tool:
• Case 1: Break-Even Case, where hydrogen market price is set to be the same as LCOH, resulting in zero NPV
• Case 2: User-Defined Hydrogen Market Price
• Case 3: NG-Correlated Hydrogen Price and the Electricity Price within Regulated Market
• Case 4: Hydrogen Market Price correlated with Natural Gas Price and Deregulated Electricity Price.</td></tr>
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Techno-Economic Assessment Reports and Tools	Key Outcomes and Significance

Report: INL/RPT-23-74644
September 2023
Comparison of Energy Storage and Arbitrage Options for Nuclear Power
	Study compares levelized cost of energy storage (LCOS) technologies for LWRs. The basis of the comparison is a 500 MWe-AC discharge capacity. The storage options evaluated include:
	• Utility-Scale Batteries:
	  - Lithium iron phosphate
	  - Nickel molybdenum cobalt
	• Power-to-Hydrogen-to-Power:
	  - High-Temperature Steam Electrolysis and H2 Combustion Turbine
	  - Reversible Solid Oxide Cells
	  - High-Temperature Electrolysis (HTE) and Solid Oxide Fuel Cells
	• Thermal Energy Storage
	  - Electro-thermal energy storage
	  - Liquid-based sensible heat thermal energy storage
	The study concluded:
	• Lithium-ion-phosphate or nickel-molybdenum-cobalt batteries have the lowest LCOS from 0–6 hours of energy storage duration.
	• The H2/fuel cell combination has the lowest LCOS storage for long-term energy storage duration beginning around 7–10 hours.
	• Thermal energy storage systems also outperform batteries for storage duties longer than about 10 hours.

Report: INL/EXT-21-62563 Revision 1 November 2021 Techno-Economic Analysis of Product Diversification Options for Sustainability of the Monticello and Prairie Island Nuclear Power Plants	• DOE-iFOA award study for Xcel Energy. Outcomes provide relevant projections for the cost of hydrogen production with nuclear supported electrolysis versus conventional SMR-H2. • Study investigates hydrogen markets in proximity to the Prairie Island and Monticello nuclear plants.

Techno-Economic Assessment Reports and Tools	Key Outcomes and Significance
Report: INL/EXT-20-57885 March 2020 Evaluation of Scale and Regionality of Nonelectric Markets for LWRs	• Establishes a library of information relative to the demand market for nonelectric products in each region. • Study shows strong potential for dedicated or hybrid FPOG hydrogen and oxygen markets in the Minnesota area and other regions coinciding with the location of key nuclear plants in these regions; he strongest markets drivers for hydrogen are petroleum refining, heavy duty fuel cell vehicles, light duty fuel cell vehicles, and ammonia, respectively. • Hydrogen storage and transportation costs data are evaluated for project-specific economic assessments. • Life-cycle analysis of CO_2 emissions are completed to compare electrolysis markets with incumbent steam/methane reforming hydrogen.
Report: INL/EXT-19-55090 August 2019 Techno-Economic Assessment (FEED study) of Nonelectricity Markets for Nuclear Reactors in the Upper Midwest U.S.	• Hydrogen production is a viable and competitive market path; current and future markets are growing in this region of the country; Markets may commence with low temperature electrolysis and transition to large-scale plants providing implementing high-temperature steam electrolysis to increase profitability when thermal energy can be extracted from the plant. • Hybrid hydrogen generation is feasible and can provide advantages to grid operations.

Nuclear Plant Integration with Hydrogen Plant and Reference Design Studies	Key Outcomes and Benefits
Report: INL/RPT-24-78743 June 2024 Preconceptual Design for Large-Scale Nuclear-Integrated Hydrogen Production Facility	This report develops a preconceptual design for a generic large-scale, 500 MW_{DC} HTE hydrogen production facility coupled with a generic 1,200 MWe pressurized water reactor (PWR) NPP. The design is comprised of three (3) parts: • Hydrogen production facility • High-voltage switchyard • Nuclear plant integration. The report addresses various factors including nuclear plant modification scope, thermal and electrical transients, equipment lead times, and stack replacement frequency. Cost estimates are developed for preconceptual system design and integration.

Nuclear Plant Integration with Hydrogen Plant and Reference Design Studies	Key Outcomes and Benefits
Report: INL/RPT-23-71939 April 2023 Preconceptual Desings of Coupled Power Delivery between a 4-Loop PWR and 100–500 MWe HTSE Plants	This study develops a preconceptual design for the integration between a large-scale high-temperature electrolysis facility (HTEF) and a nuclear power plant (NPP). Two hydrogen facility sizes are considered: 100 MW_{nom} and 500 MW_{nom}, where the subscript "nom" refers to the nominal size of the HTEF. Both steam supply designs use cold reheat steam extraction from the turbine system as a heat source. A brief comparison is also included for steam supply from main steam. A cost estimate was developed for both integration designs for plant separation distances of 250 m and 500 m. Nuclear steam extraction can provide a profit avenue for many plants and is not restricted to hydrogen production. Ammonia production, oil refining, and paper production, among other industrial processes all require thermal energy, which can be provided by NPPs.
Report: INL/RPT-23-73975 July 2023 Steam-to-Steam Thermal Hydraulic Models for Thermal Power Dispatch with a Generic PWR Power Plant Simulator	The development and implementation of two TPD system models within a full-scope simulator were completed to support continued research on FPOG. GSE Systems Generic Pressurized Water Reactor (GPWR) was selected because of its high fidelity and extensive validation. The impacts of the modeled TPD systems provides realistic responses to the existing plant systems when evaluating the performance of these designs. Two steam-to-steam heat exchanger-based systems were developed and implemented within the GPWR simulator. The two TPD designs consist of two counter-flowing loops and a series of heat exchangers. In both designs, the delivery steam line loops are identical. The extraction steam line loops are different in terms of their heat exchangers as well as the location of the extraction interface that pulls steam from secondary side steam system. The two variants are labeled Design 1 and Design 2 for brevity. Design 1 extracts steam from the main steam header while Design 2 extracts steam from the cross-under piping between the high-pressure turbine and the moister separator reheater, respectively.

Nuclear Plant Integration with Hydrogen Plant and Reference Design Studies	Key Outcomes and Benefits
Report: INL/RPT-24-76410 January 2024 Preliminary Analysis and Evaluation of Thermal Stress Induced by High-Capacity Thermal Energy Delivery	This report documents a performance evaluation of Power System Efficiencies (PEPSE) models for dispatching 30%, 50% and 70% of the plant thermal power (steam) from a generic Westinghouse 4-Loop PWR. The evaluation includes assessment of the impacts on the plant equipment due to thermal and mechanical stresses associated with high levels of thermal power dispatch (TPD).The evaluation includes assessment of the TPE effects on plant equipment including the high- and low-pressure turbines, main condenser, power train pumps, moisture separator reheaters, drain systems, feedwater heaters, and extraction steam. The impacts on the plant transients due to startup and shutdown of the thermal power extraction system, along with impacts to the main steam bypass and final feedwater temperature are also examined. The report concludes that the impact of thermal cycling due to changes in plant operations attributed to TPD up to 50% would be expected to be minor due to the relative temperature change from normal operations. These results are based on the generic plant assessment and the report emphasizes that plant-specific analysis is required.

Development of Operating Controls for Integrated Nuclear Plant Hydrogen Plant	Key Outcomes and Benefits
Report: INL/RPT-23-74650 September 2023 Advancements in Development and Testing of Thermal Power Dispatch Simulators.	This report provides an evaluation and verification of pressurized water reactor operator capability to switch thermal and electrical power between a full-scale and hydrogen plant and the grid for meeting either spinning or non-spinning reserve requirements. This effort is based on a Westinghouse three-loop pressurized water reactor (W3LPWR) simulator, which contains an industrial-grade automatic control system that was installed in the Human Systems Simulation Laboratory (HSSL) at INL in preparation for future work. Future efforts will test a new version that will include thermal power dispatch (TPD) with automated controls. The report also includes findings from a TPD integration and verification workshop conducted at the HSSL in August of 2023.

Safety Hazards, Risk Assessments, Regulatory Review Research	Key Outcomes and Benefits
INL/RPT-22-02126, Rev. 2, August 2023 Report on the Creation and Progress of the Hydrogen Regulatory Research Review Group	This report documents the activities of the Hydrogen Regulatory Research Review Group (H3RG) that was formed to generically research the magnitude of high-temperature hydrogen electrolyzer technology addition at NPP's that could potentially be accepted under a 10 CFR 50.59 evaluation and without prior NRC approval. Knowledge of this threshold would help individual licensees to understand the significant contributors to that evaluation and help them focus their design evaluations on the most important risk contributors. Several plant-specific licensed design elements were identified early in the process where additional site-specific licensing-related evaluations are expected to be required. Thus, the generic guidance described by this research is targeted at reducing complex regulatory approvals under the LAR process that might otherwise be required. Revision 2 has incorporated hazard analyses, sensitivity studies, and other analysis refinements that support the placement of (100, 500, and 1000 MWnom) HTEF co-located with a NPP. This revision also provides refinements to the calculated safe distance placement of the HTEF and other analyses that inform the overall PRA of the NPP.

Safety Hazards, Risk Assessments, Regulatory Review Research	Key Outcomes and Benefits
INL/RPT-23-74319, Revision 02023. Expansion of Hazards and Probabilistic Risk Assessments of a Light Water Reactor Coupled with Electrolysis Hydrogen Production Plants. Idaho National Laboratory.	Supplemental effort to generic PRAs for the addition of a heat extraction system (HES) to light water reactors to support the co-location of a HTEF. Improvements include: • Additional detail in the specifications of generic HTEFs for a 100, 500, and 1000 MW nominal hydrogen production facility. • An additional hazard assessment of 1000 kg of hydrogen storage is performed to determine the safe distance required for placement near the NPP. • Specific designs for corresponding HESs for the different levels of support required by the HTEFs are analyzed in the PRA model. • A hazards analysis of the specified HTEFs leads not only to effects of the quantified risk assessment for the NPP, but also qualitative hazards assessment for the community. • A seismic analysis and a high winds analysis have each been added to the PRA. The PRA results indicate that the 10 CFR 50.59 licensing approach is justified due to the minimal increase in initiating event frequencies for all design basis accidents, with none exceeding 7.7%. The PRA results for core damage frequency and large early release frequency support the use of NRC Regulation Guide 1.174 as further risk information that supports a change without a full licensing amendment review.

Safety Hazards, Risk Assessments, Regulatory Review Research	Key Outcomes and Benefits
INL/EXT-20-60104, Revision 1, 2022. "Probabilistic Risk Assessment of a Light-Water Reactor Coupled with a High-Temperature Electrolysis Hydrogen Production Plant." Idaho National Laboratory.	Expansion of probabilistic risk assessments (PRAs) for the addition of a heat extraction system (HES) to a PWR and a BWR. The report includes a new HES design, direct electrical coupling of the NPP to the HTEF, and a smaller 100-MWt HTEF analysis. The results investigate the applicability of the potential licensing approaches, which do not require a full United States Nuclear Regulatory Commission licensing review. The PRA results indicate that the 10 CFR 50.59 licensing approach is justified due to the minimal increase in initiating event frequencies for all design basis accidents, with none exceeding 5.6%. The PRA results for core damage frequency and large early release frequency support the use of RG 1.174 as further risk information that supports a change without a full licensing amendment review. Further insights provided through hazard analyses and sensitivity studies confirm with high confidence that the safety case for licensing an HES addition and an HTEF sited 1.0 km from the NPP is strong and that the placement of a HTEF at 0.5 km is also a viable case. Site-specific information can alter these conclusions.