CONSIDERATIONS FOR PRODUCING HYDROGEN WITH AN EXISTING NUCLEAR POWER PLANT

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Executive Summary

EPRI is investigating use cases for the outputs of nuclear power plants in addition to baseload electricity supply to the grid. Additional revenue streams could support the economic viability of existing nuclear power plants and one alternative mode of operation is being considered where some, or all, of a plant's thermal and/or electrical energy output is used to generate hydrogen. Hydrogen is one of several prospective applications of a nuclear plant's outputs and is of particular relevance due to the growing interest in its use as an energy carrier to achieve deep decarbonization and facilitate long-duration energy storage.

The purpose of this white paper is to provide considerations for nuclear power plant owner/operators contemplating use of thermal and/or electric power for hydrogen generation. The following considerations are discussed:

- *Economic considerations* – These include potential revenue from the sale of hydrogen, lost revenue from electricity sale, capital costs, and operation and maintenance costs.
- *Technical considerations* – These include electrolyzer selection, design of the hydrogen island including hydrogen storage, and selection of takeoff points for electricity and steam.
- *Safety considerations* – These include hydrogen ignition, hydrogen piping breaks, changes to high energy line breaks analysis, control room habitability, thermal transients, and electrical transients.
- *Regulatory and stakeholder considerations* – These include potential impacts to areas in the purview of the various regulatory agencies including nuclear regulatory entities, state Public Utility Commissions (PUC), Independent System Operator (ISOs), insurers, municipalities, Native American communities, and State and Local government agencies.

This whitepaper is the first in a series of publications to be developed. Follow on EPRI work is planned which aims to provide detailed guidance around the development of a conceptual design for a hydrogen production facility that is integrated with a nuclear unit.

1 Introduction

1.1 Purpose

This white paper defines key factors for nuclear plant owners and operators evaluating whether to use existing nuclear power plants (NPPs) to generate hydrogen, including economic, technical, safety, and licensing considerations.

1.2 Background

1.2.1 The Hydrogen Economy

Hydrogen already plays an integral role in our lives and economy today. More than 70 million metric tons were produced and consumed in 2018, primarily for the refining of fossil fuels and ammonia production [31]. However, today most hydrogen is produced utilizing steam methane reformation which results in 8–12 kilograms of carbon dioxide emitted for each kilogram of hydrogen produced [1].

There is growing interest in the expanded use of hydrogen as an alternative energy carrier to displace fossil fuels for applications that cannot be easily electrified or decarbonized, and to provide a cost-effective approach for bulk long-term energy storage. Releasing the chemical energy from hydrogen in a fuel cell or via direct combustion does not generate carbon emissions, but results in water as a byproduct.

However, in order to realize positive environmental impacts of hydrogen, the production and energy input to the process must also be low or carbon-free. Today's methods for producing clean, low-carbon hydrogen, aside from implementing carbon capture with steam methane reformation, involve the splitting of water which requires significant electrical and/or thermal energy inputs.

Governments around the world are currently making substantial investments to advance production, utilization, and infrastructure for hydrogen. The United States, European Union, and China have all laid out long term plans to develop and accelerate the deployment of hydrogen technologies.

The U.S. Department of Energy's Hydrogen Shot initiative, has a goal to reduce the price of clean hydrogen to $1/kg over the next decade [2] and the European Union (EU) has launched the EU Hydrogen Strategy with aims to accelerate hydrogen deployment by investment in research and innovation, ultimately reducing the price of delivered clean hydrogen [3]. China, the world's largest producer and consumer of hydrogen today, has identified hydrogen as a "frontier area" in the 14th Five-Year Plan, with projections of producing 100 million tons of renewable hydrogen by 2060 [32]. Additionally, countries across the Middle East have announced plans for transitions to low carbon hydrogen. With a growing market, government support, and a greater push for clean hydrogen, demand is projected to increase in the coming decades.

In addition to replacing the existing global hydrogen demand, the future demand for hydrogen could cover a wide range of uses including metals refining, heating, synthetic hydrocarbon production, and transportation fuel cell electric vehicles (FCEVs). Other potential future hydrogen applications include for emergency backup power (e.g., for telecommunications application), prime power for critical loads (e.g., data centers, defense communications facilities, hospitals, and prisons), and peak power production (potentially supplementing or by blending with natural gas) [4].

1.2.2 Motivation for Producing Hydrogen with Nuclear Power

Historically, most nuclear plants have operated as base-loaded units, which is their most economically efficient mode of operation for energy generation given the high proportion of fixed-to-variable cost. However, changing market environments resulting from increased variable generation, low electrical load growth, and historically low natural gas prices have introduced economic challenges for nuclear plants. The nuclear industry is increasingly considering alternative modes of operation, in which the nuclear plant is operated flexibly to match power output with grid demand or where some electrical or thermal energy is diverted from the nuclear plant for alternate functions while the reactor is maintained at full power.

The approach of using a portion of the energy output for purposes other than delivering electricity to the grid provides an alternative revenue stream while also maintaining a resilient and reliable supply of electricity to the grid. Potential alternate functions include hydrogen production, industrial process heat, and desalination. Hydrogen production is of particular interest due to the emerging hydrogen economy and support from governments around the world.

There are two key advantages of nuclear power for hydrogen generation over other carbon-free electricity sources [5]:

1. Nuclear power has a near-constant output and high capacity factor (over 90% [6] compared to ~40% for wind and ~30% for solar [7]). This can[1] enable operating the hydrogen generation equipment with a high utilization factor, strengthening the business case.
2. Nuclear power is well suited to provide the thermal energy inputs required by some electrolyzer technologies which operate at high temperatures and higher efficiencies than low temperature electrolysis. This also ultimately strengthens the business case by producing more hydrogen for the same energy input.

Several pilot projects are under development in the United States that are intended to demonstrate a proof of concept of the technology integration for hydrogen generation at a small scale with an existing nuclear plants [8, 9, 10]:

- ***Davis-Besse (Energy Harbor)*** – Low Temperature Electrolysis[2] – 2 MW
- ***Prairie Island Nuclear Generating Plant (Xcel Energy)*** – High Temperature Steam Electrolysis[3] – ~0.25 MW
- ***Palo Verde Nuclear Generating Station (APS)*** – High Temperature Steam Electrolysis – TBD MW
- ***Nine Mile Point Nuclear Station (Constellation)*** – Low Temperature Electrolysis – 1.25 MW

Scaling up technology integration beyond these pilot projects will necessitate broader consideration of factors related to technical implementation, business case assessment, safety, and licensing.

2 Economic Considerations

This section provides an overview of factors to be considered when developing a business case for a project to implement hydrogen production at an operating nuclear plant.

2.1 Revenue

2.1.1 Market Demand

Unlike natural gas, which is sold predominantly on the open market like many other commodities, hydrogen today is typically sold under bilateral agreements between the producer and consumer. Additionally, the production and consumption of hydrogen typically occur in close proximity to one another as hydrogen pipelines don't exist on the scale of natural gas. However, it is reasonable to believe that as the size of the hydrogen market grows the pipeline capacity and market structures could evolve to be similar in nature to the existing natural gas markets and transport capacity in certain locations.

The result of these existing constraints, market and transport, means that demand for hydrogen in the region of the nuclear plant could play a strong role in determining the potential revenue generated. Initial customers will likely be existing hydrogen consumers looking for a low carbon option. Additional markets are projected to open as the economy continues to decarbonize in areas of transportation and new technologies.

One option for utilizing the available natural gas pipeline system is blending hydrogen in natural gas for combustion in existing natural gas turbines. A number of gas turbine manufactures have shown abilities to support varying levels of hydrogen mixtures in their existing turbines, and most gas turbine manufactures are developing 100% hydrogen turbines [34].

2.1.1.1 Dresden Case Study

An Idaho National Laboratory (INL) report on the business case for hydrogen at nuclear plants in the United States [5] identified the scale, location, and accessibility of non-electricity markets to existing facilities. The report assessed the current and prospective future market size for various non-electricity products, including hydrogen. A representative example for Dresden Generating Station is shown in Figure 2-1. The current hydrogen demand in the vicinity of Dresden is about 1000 metric tons/day, and the potential future demand is 4000 metric tons/day [5]. If all the electricity generated by Dresden Generating Station [11] were diverted to hydrogen production, daily hydrogen production would be approximately 500-1000 metric tons/day, depending on various factors including

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[1] A utility might choose not to leverage this capability. For example, if the sale price of electricity is high, then it might be more profitable to deliver electricity to the grid than make hydrogen.

[2] Uses electricity only

[3] Uses electricity and steam

efficiency of the electrolyzers. Accordingly, there should be ample hydrogen demand in the region for all potential hydrogen production from the plant. The INL report and similar market analyses may be used by nuclear plant owner/operators to determine the scale of prospective customers in the vicinity of the nuclear plant, as well as to identify specific prospective customers.

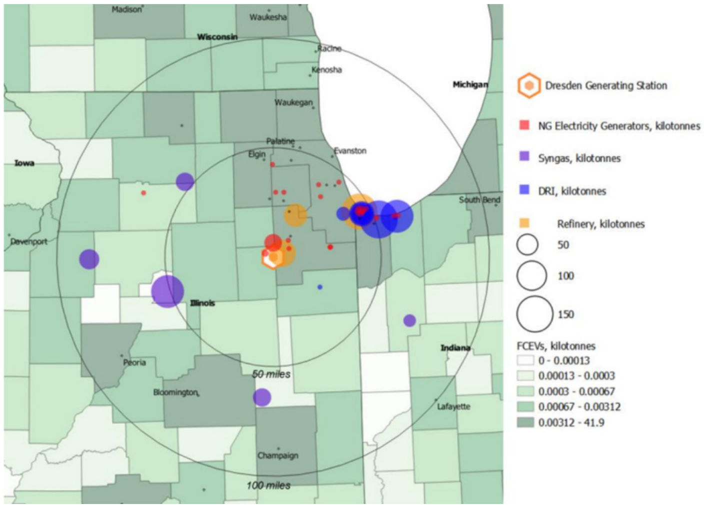

Figure 2-1. Future Potential Hydrogen Demand Near the Dresden Generating Station [5]

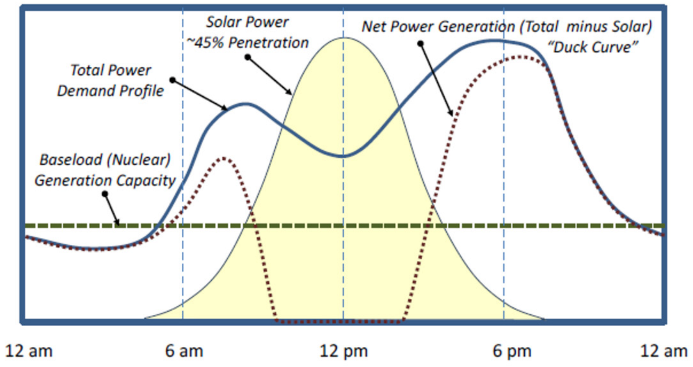

Figure 2-2. Representative Power Demand and Supply Curves for an Example Northern Hemisphere August Afternoon. Baseload Capacity (including nuclear) = 60% of total annual demand; solar capacity = 45% of total annual demand [12]

2.1.2 Demand Profile

Depending on the local electricity and hydrogen markets, several concepts of operations may be viable for achieving profitability. This section describes four types of concepts of operations, considering differences in utilization of hydrogen generation capabilities and the end uses of the hydrogen.

- *Daily Variability* – Operating the hydrogen island at a variable level of output may be beneficial to generate hydrogen only when doing so is more profitable than sending electricity to the grid. For example, in a deregulated electricity market, as solar power increases its output through the morning and into the afternoon (as shown in Figure 2-2), electricity market clearing prices drop. During these times, it can be economically unfavorable for the nuclear plant to sell electricity into the grid. At such times, the nuclear plant could instead send electricity and/or steam to the hydrogen island to generate hydrogen.

  This mode is well suited for load shifting where the hydrogen produced is consumed hours or days later for electricity production. For this mode of operation the utilization of the hydrogen production facility and the required storage must be considered in the business case.
- *Seasonal Variability* – In certain climates (e.g., very hot summers with mild winters) or geographic locations (e.g., high hydropower generation during some seasons), electricity supply and/or demand can vary seasonally. In these regions, it may be more economically favorable for the nuclear plant to generate hydrogen than to sell electricity to the grid during times of low electricity demand or high electricity supply from another source. The potential concept of operations for these nuclear plants would be to operate in the typical baseload electricity regime (100% of output sold to the grid) during the season(s) with high electricity demand, and to divert some or all of the nuclear plant's output to the hydrogen island during the season(s) with lower electricity demand.

  This mode is well suited for load shifting where the hydrogen produced is consumed weeks or months later for electricity production. This requires large storage capacity.
- *Constant Output* – Entering into a long-term hydrogen supply partnership with an industrial facility or other customer(s) is a potential arrangement for a nuclear plant to secure an offtaker for hydrogen. Industrial facilities typically operate at a high availability factor to maximize revenue. Therefore, the nuclear plant will likely need to provide a near constant supply of hydrogen via a pipeline with minimal storage.
- *Hybrid Approach Using Storage* – A hybrid approach can provide the benefit of a long-term hydrogen supply partnership while maintaining the ability to optimize revenue by flexibly partitioning nuclear plant energy output between the grid and

hydrogen. High spot or day ahead prices that provide more revenue for electrical production as compared to hydrogen production would then motivate the operator to produce electricity. This concept of operations would provide a constant supply of hydrogen to an offtaker by utilizing hydrogen storage. An INL study [5] examined a hypothetical case using a hybrid concept of operations and concluded that, in a regulated electricity market, the implementation of a hydrogen island with a hybrid concept of operations at a nuclear plant could be profitable.

2.1.3 *Cost of Production and Sale Price*

The price of low carbon hydrogen to the customer is derived from the cost of production and the cost of delivery. The cost of production from the low carbon technologies at present is dominated by the cost of electricity and the cost of delivery is driven by the proximity of the end customer to the production point. In cases where hydrogen is produced immediately adjacent to the consumption point, like large industrial consumers, the distribution cost is negligible. However, for small consumers located away from the production point, "last mile customers", the cost of delivery can be equal to the cost of production.

The external customers currently available to a given nuclear plant are highly dependent on the local industrial base, as the lack of infrastructure (e.g., pipelines) for efficient long-distance transport of hydrogen has led to a focus on developing local and regional hydrogen markets. The concept of hydrogen "hubs" or "valleys" that co-locate hydrogen generators, storage facilities, transportation infrastructure, and consumers is being explored in the United States and EU, with up to ten hubs being developed in the United States [13] and twenty-one hydrogen valleys being developed and implemented in the EU [3]. The customer base is expected to grow, with potential offtakers for hydrogen including existing hydrogen consumers who currently obtain hydrogen through carbon-intensive processes, and new hydrogen consumers who are using hydrogen for not currently established markets.

In addition to the funding and development of infrastructure for hydrogen "hubs" or "valleys", government entities are also implementing subsidies for hydrogen production from low carbon resources. In the United States the Inflation Reduction Act provides a production tax credit for each kilogram of hydrogen produced based on the carbon emissions and wage requirements. These are additional financial factors that need to be considered in a business case for the lifetime stipulated in the legislation.

Currently hydrogen is typically sold using bilateral contracts. In the future, hydrogen may be sold as an energy commodity, due to the expected increase in generation and demand, and the development of hydrogen "hubs" or "valleys". The commodity price is difficult to project; some current values are provided as benchmarks:

- Current cost of hydrogen produced by steam methane reformation: $2 per kg [14]
- Current cost of hydrogen produced by electrolysis: $2.5–$6 per kg (depending on cost of electricity among other factors), projected to drop up to 80% by 2050 [14]
- In September 2021 in Germany, the price for hydrogen at a vehicle fueling station was $11.26 per kg [15].

2.1.4. Lost Revenue from Electricity Sales

Assuming that the nuclear plant is supplying electricity and/or heat to the hydrogen production equipment, a "cost" of the hydrogen island in comparison to the existing operating model is the opportunity cost of not selling electricity to the grid. This opportunity cost varies with market conditions and the specific electricity and hydrogen prices will need to be considered as part of a detailed business case assessment for a hydrogen island under consideration. This opportunity cost may be reduced or nonexistent for a nuclear plant where the electricity cannot be sold to the grid (e.g., during peak renewable generation).

2.2 Expenses

2.2.1 *Cost Reduction from On-Site Use*

On-site use of hydrogen generated from the hydrogen island could offset some operational costs to strengthen the business case. However, the on-site demand is a very small fraction of the hydrogen that could be generated, with typical usage being a few tons a year. These uses primarily include main generator stator cooling and as an additive for chemistry control. Nuclear plants already purchase hydrogen for main generator stator cooling and primary chemistry control. Therefore, these applications could be implemented with minimal effort in the near-term. If this hydrogen were to be replaced with hydrogen produced on-site, some of the costs associated with purchasing and delivering hydrogen from a third party would be replaced by the operational cost to produce it.

2.2.2 Operating Costs

Key considerations for operating costs of a hydrogen island include operations staff, equipment maintenance and replacement, and training. Other cost considerations are the input or feedstock costs such as demineralized water and electricity required for the hydrogen island equipment including the electrolyzers and support equipment. This electricity can be drawn from the grid or as part of a house load for the nuclear unit, but each case will need to be evaluated against a variety of technical, regulatory, and business criteria. In some instances state regulators may require that the additional load be added to the grid and not as a house load to prevent taking clean and dispatchable generation away from the generation portfolio. Electricity requirements for electrolysis (determined by system efficiency) and maintenance costs may decrease over time as electrolyzer technology improves and more operating experience at large scale is obtained [5].

2.3 Project Costs

2.3.1 Capital Costs

The capital costs of a hydrogen island will be made up of several key elements:

- *Electrolyzers* – Hydrogen is produced using electrolyzer stacks. The cost of electrolyzers will be determined by the chosen electrolyzer technology and the electrolyzer size.
- *Hydrogen Island balance of plant* – In addition to the electricity being provided to the electrolyzers additional equipment will be required for heat rejection, demineralized water production, electrical equipment, and I&C.
- *Nuclear-switchyard modifications* – For both low temperature electrolysis (LTE) and high temperature electrolysis (HTE) modifications to the switchyard will be required for directing power to the electrolyzers.
- *Nuclear-steam cycle modification* – If HTE is used, and takes advantage of the thermal energy of the plant directly, plant modifications will be needed to supply thermal energy to the hydrogen island. HTE can also be accomplished with electricity only.
- *Intermediate heat exchanger facility* – An intermediate heat exchanger(s) will likely be necessary for thermal integration in the case of thermal extraction, as discussed in Section 3.3.
- *Hydrogen storage equipment* – Hydrogen storage apparatus (e.g., vessels, salt caverns) and all associated support equipment (e.g., compressors, chemical processing components).
- *New structures* – Depending on the proximity of the hydrogen island to the nuclear plant, a structure that serves as a blast shield between the hydrogen generation and storage equipment and the nuclear plant may be required. New structures could also be needed for an intermediate heat exchanger facility, storage capability, and water demineralization.

2.4 Business Considerations

In addition to the economic and financial considerations listed in the preceding sections, the delineation between ownership of the nuclear plant and the hydrogen facility will need to be determined. In all cases, whether the same entity owns both the hydrogen and the nuclear plant or two separate entities own the two facilities, responsibilities and expectations need to be clearly defined and documented to assure optimal and efficient operation. However, it is advantageous to assure that the proper regulations and regulatory bodies have oversight of the respective facilities.

3 Technical Considerations

3.1 Electrolyzer Selection

Electrolyzers use electricity to produce hydrogen. Electrolyzers are categorized as LTE, which occurs at <100°C, and HTE, which occurs at 500°C to 1,000°C. In both cases, an electrical integration with the nuclear plant is required and for HTE thermal integration with the nuclear plant can provide suitable preliminary heating through secondary side steam extraction. It should be noted that direct thermal integration, steam extraction, is not required and other heat sources may be suitable for achieving preliminary heating and vaporization.

Table 3-1 lists current prominent electrolyzer technologies and key attributes. LTE technologies include alkaline, proton exchange membrane (PEM), and anion exchange membrane (AEM). The most prominent HTE technology is solid oxide electrolytic cells (SOECs). It should be noted that in all cases the performance characteristics are continually improving and these values are representative of the technology and not a specific vendor.

Table 3-1. Selected Performance Metrics for Electrolyzers [14]

Parameter	2020			2050 R&D Target		
	LTE		HTE	LTE		HTE
	Alkaline	PEM	SOEC	Alkaline	PEM	SOEC
Electrical Efficiency[4] (system kWh/kg H_2)	50–78	50–83	45–55	<45	<45	<40
Expected Lifetime (hours)	60,000	50,000–80,000	<20,000	100,000	100,000–120,000	80,000

3.1.1 Performance Characteristics

- *Efficiency* – Efficiency of hydrogen production can be expressed as the ratio of energy input to mass of hydrogen output (kWh/kg H_2). An electrolyzer will be 100% efficient if it produces 1 kg of H_2 with 33.33 kWh of input. Increasing electrolyzer efficiency results in increasing hydrogen output for the same energy input, improving the business case. The efficiency of HTE is typically greater than for LTE, as water splitting by electrolysis requires less electrical input at higher temperatures [16].
- *Expected lifetime* – The age at which electrolytic cell performance degrades to the point that replacement is necessary. Typical expected lifetimes are greater for LTE than for HTE. The expected lifetime will drive operating costs, as additional capital will be required to replace electrolyzers that reach the end of their lifetime before the end of the desired project timeframe.
- *Operational Flexibility* – Start up time is the time it takes for a hydrogen generation system to reach 100% output from a cold start condition and can be a significant factor depending on the concept of operation. LTE units typically have a short start up time and rapid ramping capability (effectively instantaneous) over the entire output range, making them well suited for flexible operation at varying output levels. The need to maintain a higher temperature makes cycling HTE units more challenging. Current HTE units require more than 10 hours from cold start to nominal load, although there is a research goal of reducing this time to less than 5 hours [14]. Once HTE units are running, there is the capability to ramp output over 80–90% of the operational range [17]. If HTE is used for business cases that require a faster heat up, a possible workaround is to maintain the unit in a hot standby mode. However, hot standby mode uses 10–20% of the electrical energy and all required thermal energy (current HTE system designs do not include the capability to vary the steam flow) [17]. This workaround would result in reduced efficiency for an HTE system due to the energy consumption with no hydrogen produced in hot standby.

3.1.2 Supply Chain Considerations

3.1.2.1 Commercial Readiness

Selecting a technology with higher commercial readiness would benefit a project during initial deployment and throughout the project lifecycle because the supply chain would be more developed. A broader manufacturing base leads to a greater availability of electrolysis systems at the desired size, and the competition drives down prices. Additionally, there is greater availability of repair parts and services throughout the project's life, as well as more defined plans for system preventive and corrective maintenance reduce operating cost. The commercial readiness of a technology can be assessed by examining to the current scale of systems being produced and sold. LTE is commercially available in modules up to 20–30MWs and could be deployed in the near term [14]. HTE has a lower readiness level; demonstration projects have deployed SOECs at the kW-scale. Several larger demonstration projects at the MW scale are forthcoming [18, 19].

3.2.1.2 Manufacturing Capacity

Considering the expected rapid growth in demand for electrolyzers, global manufacturing capability is an important consideration. If global manufacturing capability does not increase as rapidly as demand, there could be impacts to nuclear plant owner/operators such as long lead times and high capital costs for electrolyzers. Currently, global manufacturing capability is estimated to be 2.1 GW/year, and is projected to more than double in the short-term [20]. Numerous companies have announced plans to develop manufacturing capabilities. As an example, one company is developing a large-scale manufacturing capability to support electrolyzer production of 500 MW per year in 2023, with the option to expand to 5 GW/year in the future [18].

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[4] Based on the lower heating value (LHV) of hydrogen.

Table 3-2. Overview of Hydrogen Storage Methods [22]

Storage Method	Space Footprint for ~600 ton capacity system	Cost for ~600 metric ton system	Considerations and Constraints
Low Pressure Compressed Gas (0.95MPa)	33 acres	\$600M	Energy consumption to compress
Compressed Gas (35MPa)	10 acres	\$400M	Large energy consumption to compress; specialized tank materials
Cryogenic Liquid H_2	14 acres	\$500M	Large energy consumption to liquefy; must account for boil-off
Chemical Carrier	4–5 acres	\$300M–\$1.2B	Variation in cost and readiness of chemical carriers

Current electrolyzer technologies use scarce materials, which may eventually drive up the cost of electrolyzers and limit manufacturing scale. For example, PEM electrolyzers typically use a platinum cathode and iridium anode; research and development are underway to reduce or eliminate use of these materials [14].

3.2 Hydrogen Island Design

3.2.1 Location

The location of the hydrogen island will need to be chosen to balance the advantages of close physical proximity (i.e., shorter connections for electricity and steam) with any hydrogen hazards that could affect the nuclear plant safety basis if proximity is too close.[5] Additionally, the prospective locations may be limited by available space on the nuclear plant site and could affect security, emergency planning, evacuation protocols, ease of loading and offsite transport, or other considerations.

3.2.2 Space Footprint

Space required for the hydrogen island may be an important consideration for implementation, as space can be limited within the Owner Controlled Area (OCA) and particularly the area in the near vicinity of the power block. As a benchmark, one manufacturer identifies a space requirement of approximately 675m^2, or about 7250 ft^2, for a 10MW alkaline system, including all auxiliary systems [21]. Scaling up such a system to a large portion of the nuclear plant power output would require significant land area.

3.2.3 Storage

Hydrogen storage on-site or nearby will be required if a pipeline is not available to continuously offtake produced hydrogen to the downstream supply chain. Because hydrogen has low volumetric energy density, compression, liquefication, or conversion to an alternative chemical carrier (e.g., ammonia) will be required to achieve higher energy density for more cost-effective storage and transport. The choice of a storage technology will be driven by the space footprint, the cost, and other constraints that are specific to a given technology. Additionally, it should be noted that with every chemical or state conversion the overall efficiency of the hydrogen production is reduced. The volume and duration of storage will be determined by the system size and the operational profile determined by the business case.

As an example, a comparative analysis of bulk hydrogen storage in Japan provided rough estimates for space footprint and cost for a system to store about 600 metric tons of hydrogen [22]. As discussed in Section 2, this storage capacity would be about equal to one day of hydrogen production with LTE using all the electric generating capacity of Dresden station (a two-unit boiling water reactor (BWR)). Selected results of this analysis are shown in Table 3-2 (in 2022 dollars), and the methods of hydrogen storage are described below.

Another consideration is the need for a distribution capability at the plant. For example, if hydrogen is to be transported by truck in compressed gas tube trailers to an end user, the hydrogen island design will need to include the equipment required to fill the tube trailers.

3.2.3.1 Storage Methods

- *Compressed Gas* – To attain higher energy density, hydrogen can be compressed and stored in specialized tanks. For large quantities of hydrogen, the energy required to compress the gas will be significant, which will increase overall operating costs. Furthermore, tanks that are suitable for higher pressures require specialized materials (e.g., carbon fiber), which contribute to project costs [23].

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[5] Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.91, Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants contains guidance applicable to evaluating an acceptable distance between the nuclear plant and the hydrogen island.

- *Cryogenic Liquid Hydrogen* – Large quantities of hydrogen can be stored in cryogenic liquid storage tanks, also referred to as Dewars. However, Dewars are susceptible to boil-off. The boil-off rate is estimated to be 1–3% of the tank contents per day. As for compressed gas, the energy required to liquefy hydrogen is significant, estimated to be 30% of the energy content of the hydrogen [24].
- *Chemical Carrier* – Hydrogen can be stored in a more convenient chemical form such as a useful chemical product (e.g., formic acid, ammonia), or on/within a solid (e.g., metal organic framework, clathrate hydrate) [23, 22]. If a chemical product is used, the chemical would ideally also serve a demand in the region near the nuclear plant, such that reconversion back to hydrogen would not be necessary in all cases. The energy for chemical processing to hydrogenate precursor molecules should be considered, as well as the added complexity and cost for equipment to generate the chemical product. Storing hydrogen on the surface of a solid or within a solid can provide improved stability over other methods, however, this also adds complexity to the process of storing hydrogen and moving hydrogen out of storage. Many of these chemistries are still in the research and development stage [22].
- *Salt Cavern Storage* – Geologic storage, particularly in salt caverns, is the most efficient way to store hydrogen on a large scale [25]. However, the feasibility of using salt cavern storage or other means of geologic storage would depend on the proximity of the nuclear plant to geologic storage areas. Figure 3-1 shows potential geologic storage regions in the United States.

3.3 Nuclear Power Plant Integration

Integration of hydrogen production at a nuclear power plant will require several interfaces for both LTE and HTE. In both cases there will be electrical and I&C interfaces required with the nuclear plant, and in the case of HTE there could be thermal integration as well. Each of the new interfaces for the hydrogen island with the nuclear plant will be carried out in accordance with the owner's quality assurance procedures. Considerations for these impacts are described in the following sections.

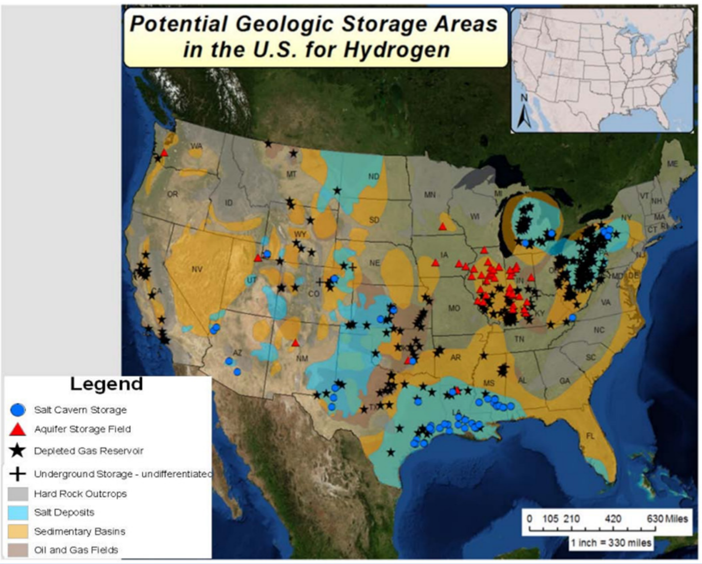

Figure 3-1.U.S. Geography that may have potential as underground storage as well as existing natural gas geologic storage formations [26]

3.3.1 Electrical Integration

Design considerations for how to electrically connect the electrolyzers to the plant for both LTE and HTE include:

- *Integration location* – Electrical integration of the hydrogen island can occur in two manners, "before the meter" or "after the meter". In the case of connecting before the meter the electricity is viewed as a house load and the cost of electricity is the cost of production from the plant, however when a system is connected after the meter the cost reflects market conditions. The electrical connection point will be determined both by physical and regulatory factors. Physical factors include items such as bus capacity and impact to the station electric plant, where regulatory factors would include house load determination and when electricity can be diverted from the grid to hydrogen production.
- *Impact to station electric systems* – The impact to electrical systems at an existing nuclear power plant will need to be evaluated to assess the new normal operating conditions and transient conditions that may exists following the addition of electrolyzers. While nuclear plants today have analyses for loss of offsite power (LOOP) and how the plant responds, thermally and electrically, depending on the size of the hydrogen system new,

unique transients may be introduced such as losing the grid and keeping the hydrogen island, or losing the hydrogen island and keeping the grid. These impacts will need to be mitigated or managed and include:

- Potential new electrical transients and electrical design model reviews;
- Expected greater variability of the electricity demand; may require modifications to nuclear plant secondary control systems and turbine generator control systems.
- Electromagnetic interference and harmonics; may require shielding and filtering to mitigate.
- Protection coordination; may require changes to protection coordination schemes.
- Additional reactive load; may result in a power factor that is not consistent with bulk power system requirements (e.g., the Federal Energy Regulatory Commission (FERC) Large Generator Interconnection Agreement) and require additional equipment to mitigate.

3.3.2 I&C Integration

In addition to the electrical integration, both LTE and HTE, will require control integration with the nuclear plant. There exist several options for control arrangements.

- ***Hydrogen Island Controls in the Nuclear Control Room*** – The hydrogen island controls could be integrated into the nuclear control room. While this reduces the number of control rooms required and potentially eases communication between the operators, it will add complexity to the nuclear control room and add personnel to the nuclear control room. Additionally, the nuclear control rooms tend to have limited available space therefore adding additional panels and routing cable would require evaluating existing analyses of record.
- ***Standalone Hydrogen Island Control Room*** – A new structure could be built to house the hydrogen island control room. This would reduce the complexity of the nuclear control room, keep the operators separated, and help keep the hydrogen production separate from the nuclear production. This will however increase the capital expense in needing to add another structure and require additional real estate for the structure.

3.3.3 Thermal Integration

For an HTE system, a supply of thermal energy will be required. The most common thought is to extract steam from the turbine cycle of the nuclear plant, but other options exist such as electric boilers. In most cases the thermal energy supplied is about 10-20% of the electrical energy supplied, for example a hydrogen facility requiring 10MW- electric will require 1-2MW-thermal around 150°C.

Design considerations for the steam extraction from the nuclear plant's turbine cycle include the following:

- ***Takeoff location*** – The steam diversion point will be chosen based on the pressure and temperature that are suitable for the hydrogen island and intermediate heat exchanger performance. However, steam diversion points at different points in the steam cycle will have different impacts on normal operation of plant systems by reducing the steam flow. Potentially impacted components include the feedwater heaters, turbines, the main condenser, moisture separators/moisture separator reheaters, heater drains, electrohydraulic control systems, and condensate polishing systems.
- ***Condensate return*** – After the steam condenses in the intermediate heat exchanger it will need to be returned to the condensate system. The exact return location will be determined in the design, but several options are available. It could simply be returned to the condenser, but the condensate from the intermediate heat exchanger will likely be well above typical turbine exhaust temperatures. Another option, which would require a pump, would be to return it along the low-pressure feedwater heaters to extract the remaining thermal energy.
- ***Intermediate heat exchanger*** – Separation of the nuclear plant and hydrogen island steam systems is expected to be necessary to provide reasonable assurance for the control of radioactive material and to maintain control of the secondary working fluid (e.g., chemistry). An intermediate heat exchanger and associated support equipment could serve this purpose, transferring the thermal energy to an independent loop that serves the hydrogen island.
- ***Pipe and cable routing*** – Adding new pipe and/or electrical cable runs could be complex in the context of avoiding interferences with and impacts to the existing nuclear plant infrastructure. The hydrogen island configuration and interfacing systems should be designed to not interfere with existing flood protection design, fire protection, and fire suppression systems.

4 Safety Considerations

4.1 General Hydrogen Facility Safety

Hydrogen ignition is one of the key safety considerations. Proper ventilation and leak detection methods should be employed to ensure the safety of the facilities. As an inherently low-density gas, hydrogen tends to dissipate quickly in the atmosphere, helping to reduce ignition risk and highlighting the importance of ventilation. Relevant requirements promulgated by the National Fire Protection Agency (NFPA) and the American Society of Mechanical Engineers (ASME) are listed below.

- *NFPA 2* – Hydrogen Technologies Code - fire safety requirements for all hydrogen technologies, including piping, hydrogen generation systems, and bulk gaseous hydrogen systems (including separation distances between the hydrogen island and other buildings, other hazardous materials, property lines, etc.).
- *NFPA 55* – Compressed Gases and Cryogenic Fluids - requirements for the storage, use, and handling of hydrogen in compressed gas systems, including separation distances.
- *ASME B31.12-2019* – Hydrogen Piping and Pipelines - requirements for components, design, installation, and testing of hydrogen piping and pipelines.

4.2 Potential Impact of Hydrogen Island on Nuclear Power Plant Safety and Operation

In the context of a nuclear plant, the presence of a hydrogen island has a potential impact on nuclear safety and operation. Existing nuclear plants store and use hydrogen for generator cooling and chemistry control, and the nuclear safety considerations have been evaluated. These evaluations typically consider quantities of <250 kg and locations close to the turbine building. Regulatory guidance is already in place for hydrogen storage and use at nuclear plants. This information will be applicable to a hydrogen island associated with a nuclear plant and should be considered in the design of a hydrogen island. Considerations include:

- *Hydrogen Explosion* – An explosion at the hydrogen island could impact the nuclear plant. Methods for mitigating the impact of an explosion include construction of concrete walls or blast panels between the plant and the hydrogen facility, increased distance between the hydrogen facility and the nuclear plant, or use of an earthen berm. The nuclear plants fire protection program may be responsible for the proper storage of hydrogen and providing fire hazard analysis regarding hydrogen explosions if the facility is within the boundary of the plant [27].
- *Hydrogen Piping Breaks* – Hydrogen piping breaks can result in hydrogen concentrations that are high enough to cause an explosion. Preventive measures are required to avoid the surrounding area having a hydrogen concentration exceeding 2%. These preventive measures can include using excess-flow check valves to prevent accumulation of hydrogen gas [28]. As mentioned previously, proper ventilation can reduce the risk of explosion.
- *High Energy Line Breaks* – The addition of new piping for a steam diversion for HTE could increase the probability and impact of high energy line breaks and may impact the licensing basis. The probabilities and impacts, as well as mitigations, should be considered.
- *Thermal Transients* – In cases where steam extraction is used in HTE the potential exists for introducing new transients or normal operations occurring in a new range. The new transients which may be introduced would fall into the over- and undercooling categories, but the new transient should be bounded by existing transients such as Main Steam Line Breaks or Loss of Offsite Power.

  Operationally, the addition of steam extraction and condensate return could impact feedwater level and extraction steam conditions depending on the amount of diverted steam. Turbine cycle performance and sensitivity will need to be evaluated for the operational condition's desired in the business case.
- *Electrical Transients* – A hydrogen island trip could result in a rapid decrease in electricity demand, which results in more active power being exported to the grid. This may result in a voltage rise that is unacceptable to the grid operator. Therefore, reducing the nuclear plant's power output may be required. Existing control systems will likely not be optimized for this operating regime and may require modifications to support managing potential upsets of the hydrogen island. Adding a hydrogen island can potentially increase the probability of load rejection, which is the sudden loss of load causing an over-frequency condition and over-speed condition in the main turbine.

5 Regulatory Considerations

Due to the safety considerations discussed in Section 4.0, the hydrogen island facility can pose new hazards to the nuclear plant that may require regulator engagement. Selected technical considerations identified in section 3.0 may require specific evaluation in the context of the plant license. In general, the process for regulator engagement to implement a hydrogen island would include reviewing the current licensing basis, assessing the impact of any new hazard(s) presented by the hydrogen island, and determining the need to engage with the regulator to address impacts and license changes. It is recommended that the regulator be engaged early in the process for hydrogen integration to help facilitate timely identification of regulatory challenges.

6 Other Considerations

- *Existing Equipment Warranty* – The equipment which exists at the nuclear plant today, both electrical and mechanical, may have performance warranties in place for the operational conditions of the plant today and new operational conditions for the turbine cycle may void those existing warranties.
- *Water Rights* – Demineralized water requirements are expected to be significant: 9 kg of water are required as electrolyzer input per 1 kg of hydrogen produced [30], which equates to approximately 1 million gallons per day for a large hydrogen island that produces 500 metric ton per day. In addition, there will be water needs for cooling of the electrolyzers and some portion of the water will be rejected to meet the purity requirements for demineralized water. With both PEM and AE the cooling water demand can be 3-5 times the water demand for hydrogen production [35]. Considerations for water rights include identifying a source and obtaining a withdrawal permit if required. Additional systems for demineralization may also be needed to supply this volume.
- *Non-Nuclear Regulatory Entities* – Non-nuclear regulatory entities including state public utilities commission (PUC), independent system operators (ISOs)/regional transmission organization (RTOs), and FERC could be stakeholders in a decision to implement a hydrogen island. The considerations for these stakeholders would center around the impacts of a diverting the nuclear power plant's electricity output for utility use rather than delivering the electricity to the grid.
- *Security* – A hydrogen island may impact existing site security plans, depending on the location of the hydrogen island, its size, and the potential impact of a hydrogen detonation. Specific considerations would include increased staffing, expansion of the site, and whether the hydrogen island site is categorized as an industrial site or as part of the OCA.
- *Environmental Permitting* – Environmental permitting requirements associated with any large construction project would apply to a hydrogen island. Authorities having jurisdiction would have an interest in potential impacts to environmental resources in the vicinity including water, land, flora, and fauna.
- *Insurance* – A hydrogen island is a new asset associated with a nuclear plant and also introduces a new hazard to the nuclear plant, so it could be of interest to nuclear insurance providers for increasing insurance rates. As an example, the considerations for insurance providers would include the risk of the hydrogen island as a target for external threats.

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