Rethinking Deployment Scenarios for Advanced Reactors

Scalable Nuclear Energy for Zero-Carbon Synthetic Fuels and Products

Technical Brief — *Advanced Nuclear Technology*

1 Introduction

Growing interest in and need for cost-effective, mature, and scalable technology options for decarbonizing the world's energy markets and infrastructures call for rethinking and reimagining the way in which energy carriers are produced. EPRI is exploring how the full potential of nuclear energy can be brought to bear on the intertwined challenges of meeting future global energy demands, maintaining or improving quality of life, and mitigating environmental degradation.

Recent nuclear power plant construction projects in the United States and Europe have been plagued by significant delays and cost escalation. These experiences call into question nuclear energy's viability as an option for meeting future energy demand and mitigating the effects of emissions on the timeframes and at the scales required. In this study, EPRI seeks to identify potential deployment paths to low-carbon and energy-secure futures through application of the unique combination of attributes offered by nuclear (fission) technology as an energy-dense, dispatchable, non-emitting, and scalable heat source.

EPRI presents four conceptual scenarios illustrating how advanced nuclear heat sources can be configured, fabricated, and delivered to participate in and decarbonize global fuel and other commodity markets (Table 1). The scenarios employ innovative deployment models—for the commercial nuclear industry at least—to substantially reduce project cost, schedule, and risk. The first three ship-based models leverage existing or near commercial chemical technologies and processes. Therefore, minimal to no additional technology discovery or innovation is required except for their integration.

Table 1. Scenarios and products addressed in study

#	Scenario	Product	Resource Being Substituted	Deployment Setting and Model	Compatibility with Existing Infrastructure†	Major Changes Required†
1	Ammonia production for marine shipping fuel	Carbon-free ammonia (NH_3)	Shipping fuel	Offshore (FPSO)	Medium – High	Ammonia burning engines compatible storage and distribution
2	Commercial airline fuel production	Net-zero Jet A	Fossil Jet A	Offshore (FPSO)	High	None
3	Ammonia, power, and desalinated water production for coastal cities	Carbon-free ammonia, electricity and desalinated water	Multiple	Offshore (FPSO)	Medium – High	Ammonia burning equipment compatible storage and distribution
4	Blending H_2 into existing gas network	Carbon-free hydrogen	Natural gas	Onshore (on-site fabrication, installation, and operation)	High if <20% of blend concentration	Upgrades needed for >15–20%

† Compatibility and required changes will vary for substitutes like ammonia depending on end-use, extent of adoption, location, among other factors. The characterizations provided are intended to indicate the relative ease of adoption with respect to changes required of producers and customers.

The fourth land-based, vertically integrated approach is more aspirational in nature, incorporating an on-site construction-installation-operation deployment model. High temperature operation of advanced non-light-water reactors is leveraged for highly efficient production of hydrogen via a less mature thermochemical process.

The produced commodities are intended to provide drop-in substitutes for large, established markets to minimize or eliminate disruption of an existing supply chain infrastructure and consumer behavior.

1.1 Terminology

Decarbonization of recalcitrant sectors, such as heavy-duty transport, represents one of the promising applications of advanced nuclear heat sources through new deployment models. Consistent and clear use of terminology is important for distinguishing among different carbon abatement pathways. For the purposes of this study, the following terms and definitions apply throughout:

- ***Net-zero:*** Specific term describing resources, technologies, and products characterized by net carbon emissions equal to zero. Any emissions produced from operations, processing, or use are balanced by an equivalent amount of carbon removal or offsets.
- ***Carbon-free:*** Specific term describing resources, technologies, and products characterized by the absence of fossil fuel utilization or carbon emissions to the environment during operations, processing, and use.
- ***Carbon-negative:*** Specific term describing resources, technologies, and products characterized by net negative carbon emissions. Any emissions produced from operations, processing, or use are balanced by a greater amount of carbon removal or offsets.
- ***Zero-carbon:*** General, inclusive term describing resources, technologies, and products than can be characterized as net-zero, carbon-free, or carbon-negative.

1.2 Deployment Scenarios

Deployment scenarios are described with traceable techno-economic analyses based on public data and commercial cost estimates. Indicative economics suggest that the proposed products, including liquid fuels and potable water, can be cost-competitive with current market benchmarks (Table 2) and provide practical CO_2-free or CO_2-neutral alternatives to current fossil fuel-based production options.

A common, key enabler of these scenarios is the complete shift to factory- and shipyard-based manufacturing and standardization using open architecture approaches for delivering the nuclear plant and production platforms in controlled, engineered environments. Three scenarios are based upon modern large-scale, shipyard-manufactured, floating production, storage, and offloading (FPSO) facilities. These facilities can use heat and electricity from high-temperature nuclear heat sources to produce commodities such as ammonia for shipping, synthetic jet fuel for aviation, dispatchable electricity, and potable water without the need for fossil hydrocarbons. A fourth scenario features an onshore facility that integrates manufacture, assembly, and installation of structures, systems, and major components with on-site production of hydrogen—dubbed *gigafactory* hereafter—for blending and injection into an existing natural gas network.

The central role for nuclear in these and other breakthrough scenarios is driven by the unique combination of attributes nuclear generation offers in a compact package. Nuclear reactors can generate scalable quantities of heat on demand without emissions or the need for replenishment of fuel (or any external consumables) for years to decades. Without the need for external inputs (fuel, sunlight, wind, or potential/kinetic water energy), the limits on scalability of nuclear deployment are established mainly by the nuclear fuel resource supply and continuous access to a suitable ultimate heat sink.

Light water reactors (LWRs) continue to represent the dominant nuclear technology on land for electricity generation and at sea for naval propulsion. And while LWRs are reliable and proven, a wide array of designs that employ primary coolants other than water are being developed for commercial deployment in the 2030 – 2040 timeframe.[1] These non-LWRs universally offer higher outlet temperatures than LWRs (above 500°C) and most also offer increased safety and operational margins by operating at low (near atmospheric) pressures or employing inert He gas in combination with robust, refractory TRISO-based fuels.[2]

1 Advanced nuclear heat sources or high-temperature nuclear heat sources could include high-temperature gas-cooled reactors (HTGRs), molten salt reactors (MSRs), and sodium-cooled fast reactors (SFRs), and other advanced nuclear reactor concepts with primary system outlet temperatures exceeding 500°C. In this context, compact fusion energy heat sources would also apply once mature and deployable.

2 TRi-structural ISOtropic (TRISO) particle fuel comprises a fuel (typically uranium) kernel encapsulated in three successive layers (carbon-ceramic-carbon) to provide robust containment of fission products up to 1800°C.

Table 2. Benchmarks for competitive product pricing without abatement of carbon emissions

Product	Price	Units	Basis	Source
Kerosene-Type Jet Fuel (Jet A)	94	USD/bbl	2010–2019 average wholesale price	[1]
Ammonia (NH_3)	200	USD/tonne	Estimated pre-shipment cost of ammonia produced with $3/MMBtu natural gas	[2]
Hydrogen	0.7 – 1.6	USD/kg	2019 levelized production cost from natural gas	[3]
Electricity	68.3–185 102–334	USD/MWh	2019 OECD industry 2019 OECD residential	[4]
Desalinated Water	0.64–2.86	USD/m^3	2016 prices for reverse osmosis technology	[5]

Advanced fission reactors as non-emitting, energy dense, dispatchable heat sources can produce electricity and high temperature heat within a very small ecological footprint. They are well suited to supplying energy for the production of hydrogen and hydrogen-based products such as CO_2-neutral or -negative synthetic fuels. Hydrogen (H_2) is a CO_2-free energy carrier, storage medium, and primary constituent element in commodities such as ammonia (NH_3) or synthetic, drop-in substitute fuels such as commercial aviation fuel–commonly referred to as Jet A.[3]

Designing plants that incorporate these heat sources to produce liquid fuels, serving large and well-established global markets, represents a transformational opportunity for rapid and scalable deep decarbonization. These markets are large enough to drive deployment on a global scale, enabling high-volume manufacturing of these new production plants. Following a design and delivery process where the entire plant is manufactured in a single shipyard, substantial reductions in capital costs and build times should be achievable.

1.3 Commercial and Technology Bases for Scenarios

The scenarios are offered as feasible commercial options ready for initial demonstration at scale in the coming decades and scaling by 2050. They are based on four primary lines of evidence reflected in Figures 1–5:

1. The fabrication methods and infrastructure required to support the proposed scenarios already exist at scale at commercial shipyards, particularly in Asia (Figures 1 and 2).
2. Deployment of nuclear reactors on ships predate the commercial nuclear industry. Consequently, the experience with naval nuclear propulsion spans seven decades (Figure 3).
3. Floating nuclear plants for generation of heat and power also date back decades, and recent interest in barge-mounted nuclear plants is growing. Russia's Rosatom commissioned and deployed the twin unit 70 MWe Akademik Lomonosov combined heat and power plant in the Arctic port of Pekev in 2019 (Figure 4). China is reportedly nearing completion of a 140 MWe floating nuclear plant—the ACPR50S.
4. The offshore oil and gas industry currently relies on a fleet of large floating production, storage, and offloading (FPSO) vessels for the in-situ collection, processing, storage, and transfer of hydrocarbons in lieu of land-based petrochemical facilities (Figure 5).

Each scenario employs factory-based or shipyard-based manufacturing for assembling systems and components. Three scenarios include a concept for a large-scale, floating production storage and offloading (FPSO) facility that uses heat and electricity from high-temperature nuclear heat sources to produce hydrogen, and from that, produces ammonia or synthetic hydrocarbons (synfuels). In addition, the FPSO can be configured to also produce electricity, and/or desalinated water. Appendix A provides additional information on key sources used in development of techno-economic assessments and estimates for each scenario.

3 Jet A fuel is used for aviation in the United States and a variant, Jet A-1, is used throughout the rest of the world. They have the same flash point and autoignition temperature but differ only slightly in their freezing point, specific energy, and energy density. For the purposes of this report, Jet A is used generically to represent both.

*Figure 1. **Modern shipyard fabrication model.** The Samsung Heavy Industries Co. shipyard in Geoje, South Korea illustrates the capability and capacity of modern shipyards to fabricate the largest ships in the world—including oil tankers, container ships, and floating production, storage and offloading platforms. Photographer: SeongJoon Cho/Bloomberg via Getty Images. Used with permission.*

*Figure 2. **Modular construction.** Modular construction is the industry standard for shipyard-based fabrication and assembly. Shown here is a Maersk Triple-E class vessel under construction, at the DSME shipyard in Okpo, South Korea. Used with permission according to Creative Commons terms. By Maersk Line - Flickr photo page, CC BY-SA 2.0, https://commons.wikimedia.org/w/index.php?curid=27646189.*

*Figure 3. **Ship-based nuclear power plants.** Commercial nuclear technology was born in naval propulsion applications beginning with the first nuclear submarine, the USS Nautilus (SSN-571) commissioned in 1954. Today, U.S. aircraft carrier and submarine fleets are exclusively powered using nuclear energy. Image courtesy of U.S. Navy. (The appearance of U.S. Department of Defense (DoD) visual information does not imply or constitute DoD endorsement.)*

Figure 4. Ship-based nuclear generation for commercial power and heat. In 2020, the floating Russian nuclear power station Akademik Lomonosov moored in an arctic port completed commissioning and began supplying power to the Bilibino regional power system and heat to the port town of Pevek. Photographer: Lev Fedoseyev via Getty Images. Used with permission.

Figure 5. Ship-based production of fuels and other commodities. The petroleum industry has moved to floating production, storage, and offloading platforms (FPSOs). The Petronas Dua floating liquefied natural gas (LNG) vessel is pictured during construction at the Samsung Heavy Industries Co. shipyard in Geoje, South Korea in 2019. Photographer: SeongJoon Cho/ Bloomberg via Getty Images. Used with permission.

The FPSO units are inspired by the *Petronas floating liquefied natural gas dua* (PFLNG 2)—an FPSO owned by the Malaysian oil and gas company Petronas[4]—as well as by other floating production facilities that have been designed for challenging environments (for example, the BP Glen Lyon harsh water FPSO) and high production capacities (for example, the Shell Prelude FPSO).

Space constraints of FPSO equipment installation can increase costs; however, these can be offset by efficiency gains and cost reduction afforded by incorporating multiple, modular heat source units and subsystems in a fully engineered manufacturing environment such as a shipyard or factory, particularly if many units will be serially manufactured.

4 The PFLNG 2 "Dua" FPSO is a large, manufactured floating gas processing and LNG production unit commissioned in 2020 for operation in the Rotan gas fields off the coast of Malaysia.

The fourth, most aspirational scenario describes an onshore gigafactory concept to produce clean hydrogen by pairing high temperature reactors directly with a high efficiency thermochemical hydrogen generation process. This scenario represents a significant departure from established construction, installation, and business models, and invokes non-commercial thermochemical hydrogen process technology.

1.4 Precedents for Financing, Constructing, Regulating, and Operating Offshore Production Facilities

There are approximately 6,500 offshore oil and gas platforms [6] and 440 civilian nuclear power reactors operating globally [7]. These assets are supported by established financial, construction, operational, regulatory, and insurance institutions and infrastructures that represent annual investment in the billions of USD.

1.4.1 Nuclear Propulsion for Shipping

There is well established precedence for designing, regulating, and deploying nuclear reactors for offshore applications. Nuclear reactors were first designed and deployed for submarine propulsion in the 1950s, and thousands of reactor-years of reactor operations and hundreds of millions of miles traveled have been accumulated to date [6]. The U.S. Navy alone has deployed more reactors at sea than have been built for onshore applications in the United States with no reported nuclear incidents.

A total of nine nuclear powered icebreakers have been constructed and operated—all by Russia and its predecessor, the former Soviet Union.

Four nuclear-powered civilian ships have been deployed by four different nations [8].

- The United States launched the NS Savannah in 1962 as a demonstration of the peaceful use of nuclear power; its relatively small size and cost as a one-of-a-kind vessel proved uneconomic, resulting in removal from service one-decade later in 1972.
- Germany launched the Otto Hahn in 1968 and operated the vessel without performance issues over ten years spanning a total of 126 voyages and 1.2 million kilometers; however, the cost of operations and maintenance proved uneconomic, and the vessel was refitted with diesel propulsion in 1979.
- Japan launched the Mutsu as a nuclear-powered cargo ship in 1970; after performance and design issues including inadequate reactor shielding, the ship completed ocean trials after refurbishment and was decommissioned in 1992 without ever entering commercial service. The vessel itself was refitted with diesel engines and subsequently relaunched under a new name.
- One nuclear powered merchant cargo ship, the Russian Sevmorput, remains in operation. Originally delivered to state-owned Murmansk Shipping Company in 1988, the Seymorput survived decommissioning plans, completed a two-year refit and refueling in 2015, and recently returned to service after requiring non-nuclear-related repairs in 2020 [9, 10].

1.4.2 Floating Nuclear Power Plants

Nuclear power has also been deployed for ship-to-shore power and water desalination services. The first floating nuclear power station, MH-1A, was a pressurized water reactor installed on converted World War II Liberty Ship that provided 10 MW of reliable electricity needed to support operation of the Panama Canal Zone from 1967 to 1975 due to the underdeveloped land-based power system at the time (Figure 6) [11]. MH-1A was the last in a series of portable reactors deployed as part of the U.S. Army Nuclear Power Program, which provided small reactors for electrical generation and space-heating at other remote and strategically important sites in Greenland, Wyoming, Antarctica, and Alaska.

Figure 6. Undated photograph of USS Sturgis moored and supplying power to land in the Panama Canal Zone, circa 1967 – 1975. Image courtesy of the U.S. Army Corps of Engineers. https://www.nab.usace.army.mil/Media/Images/igphoto/2001966083/

In the 1970s, GWe-scale offshore civilian nuclear plant designs were developed and pursued well into licensing for Westinghouse's Atlantic Nuclear Power Plant in the 1970s. As part of this effort, the environmental and regulatory review processes for commercial offshore applications were exercised and demonstrated to the point of authorization of plant fabrication. Throughout the 1970s, a private-sector venture pursued state and federal regulatory review for the Offshore Power Systems proposal, which entailed multiple factory-manufactured floating reactors to be sited off the east coast of the United States. The U.S NRC review was generally positive and resulted in a final environmental statement that included a recommendation for issuance of a license to remotely fabricate the nuclear plants in a purpose-built shipyard-like facility [12, 13]. A subsequent addendum to the NRC final environmental statement on OPS states [14]:

> *On the basis of the analysis and evaluation set forth in this generic statement concerning the construction and operation of nuclear generating stations using floating nuclear power plants in several biogeographical provinces in the U.S. coastal zones of the Atlantic Ocean and the Gulf of Mexico, after weighing the environmental, economic, technical, and other benefits of employing the floating nuclear plants against environmental and other costs and after considering certain other alternatives, it is concluded that the eight floating nuclear power plants proposed for manufacture can, with a reasonable degree of assurance, be sited and operated as electric generating stations either at offshore or shoreline sites.*

More contemporary examples of floating/offshore nuclear power generation applications include:

- The French Flexblue concept proposed in the late 2000s [15];
- Rosatom's 70 MWe Akademik Lomonosov commissioned on December 19, 2019 [16];
- China General Nuclear's (CGN) 140 MWe floating nuclear plant (the ACPR50S) under construction [17]; and
- The Massachusetts Institute of Technology offshore concept [18].

Floating nuclear power plants have been described as "…largely compatible with the existing rules of International Law" [19]. However, rules and issues, particularly around export to non-nuclear countries, will need to be further articulated. Lloyd's Register, one of the world's premier classification societies[5] for ships—and the oldest dating back to the 1760s—has been working with CGN on developing an international licensing framework for floating reactors [19].

1.4.3 Irradiated Nuclear Fuel Shipments

The shipment of irradiated (used or spent) nuclear fuel on land and at sea represents another important experience base on which the feasibility of offshore applications of nuclear technology can be evaluated. In the United States, thousands of shipments of commercial spent nuclear fuel have occurred over four decades without radiological releases or public harm [20]. Likewise, more than 80,000 metric tons of used nuclear fuel have been transported in over 20,000 shipments globally since the 1970s without environmental releases or public harm [21].

Review of the extensive international experience with spent nuclear fuel shipments finds no cases of injury or loss of life caused by the radioactive nature of the material transported [22]. In general, there have been few transportation accidents worldwide in the history of transporting spent fuel, and none have had significant radiological consequences. International protocols have been in place for more than 65 years, and routine shipment of nuclear fuel (fresh and irradiated) continues to occur without incident.

5 Classification societies are non-governmental organizations that (1) establish and maintain technical standards for the construction and operation of ships and offshore structures (2) certify construction complies with the standards for the respective shipping class; and (3) conduct in service inspections to verify ongoing standards compliance. The largest shipping classification societies are Det Norske Veritas (DNV), the American Bureau of Shipping (ABS), Nippon Kaiji Kyokai (ClassNK) and Lloyd's Register.

1.5 Caveats

This study is intended to identify potential commercially viable pathways to support scalable decarbonization of hard-to-decarbonize industries through the application of advanced nuclear energy generation and new deployment models. Collectively, the evidence assembled for this study indicates the integration of advanced nuclear generation with shipyard fabrication and offshore production facilities—as described in three of four scenarios–is feasible. This evidence includes:

- The economy, scale, and efficiency of modern shipyards;
- The history and extent of nuclear reactors deployed on barges and ships;
- The existence of and commercial experience with offshore nuclear oversight and regulatory infrastructure;
- The established industry experience with large chemical processing facilities on FPSOs, and
- Prior and ongoing research, development, and demonstration (RD&D) on nuclear energy for H_2 production.

However, the challenges for commercial implementation should not be understated, and it is important to acknowledge important considerations, uncertainties, and risks that remain unresolved and/or are not fully addressed in this study [23]. These include the following issues outlined below.

1.5.1 Nuclear Non-proliferation

Any proposal to change and/or expand the manner in which fission-based energy generation is deployed at large scales will need to adequately address national and international concerns related to the potential for the spread of nuclear weapons, related technology, or fissile material to countries (states) that do not already possess them and to non-state actors of concern. However, consideration of nuclear non-proliferation aspects of the deployment models examined falls outside the scope of the study.

1.5.2 Nuclear Safeguards

Any proposed change to or expansion of nuclear energy deployment at the scales envisioned in this study will also need to adequately provide for means by which the International Atomic Energy Agency (IAEA) can verify compliance of host countries with their legal commitments under IAEA safeguards agreements. Consideration of international nuclear safeguards is outside of the scope of this study.

1.5.3 Security

As with any industrial asset, adequate security staffing and measures will be required to address insider and external threats seeking to access, disrupt, or sabotage the facility or remove nuclear/radioactive material. While staffing requirements for security are considered, more extensive evaluations of security and physical protection are not explicitly addressed in this study. Other proposals for floating/offshore nuclear power plants do address physical protection measures, including physical barriers, access control, and detection aids [24].

1.5.4 Compatibility with International Treaties, Laws, and Agreements

Deployments of barge- and ship-based nuclear energy systems have been demonstrated, and there is an abundance of experience with maritime conveyance of fresh and irradiated nuclear fuel. However, expanded application of nuclear energy at the scales proposed herein, particularly for deployment outside of the territorial waters of the exporting nation, will likely require consideration in the context of international treaties, laws, and other agreements beyond IAEA safeguards.

1.5.5 Extension and Updating of Nuclear Regulatory Infrastructures

As with the integration of nuclear quality and standards with commercial shipbuilding, updating and extension of current nuclear regulatory infrastructures for host countries are likely needed for enabling cost-competitive deployment and operation of ship-based nuclear energy systems presented in the three relevant scenarios.

1.5.6 Integration of Nuclear Quality and Standards into the Shipyard Model

While the integration of nuclear power with shipyard construction is a standard practice for naval propulsion and other specialized applications, the viability of transferring the practice to the large-scale commercial shipyard environment proposed in this study has not been demonstrated. Therefore, the merging of these two domains for competitive construction of floating nuclear powered FPSOs and land-based units will require substantial development and demonstration representing non-recurring costs not fully reflected in the techno-economic assessments presented herein. Moreover, additional costs and activities required for construction of nuclear-bearing hulls are likely correlated with other factors described above, such as safeguards and security.

While a number of issues remain to be addressed and resolved, these appear bounded and are generally institutional (not technical) in nature.

1.6 Application of Results

Point estimates of future commodity production costs are for illustration purposes only. The scenarios, deployment models, and cost estimates described below are provided as a vision for scaling nuclear energy for greater cost competitiveness and decarbonization. They are not intended as recommendations for or forecasts of future energy generation portfolios.

2 Reference Nuclear Heat Source

This study is fundamentally technology agnostic with respect to the nuclear heat source, as the process technologies primarily use electricity in the first three scenarios presented. However, for the purpose of techno-economic assessment, a reference high-temperature advanced nuclear (fission) heat source technology is adopted.

2.1 Nuclear Heat Source for FPSO-based Scenarios

For the shipyard manufactured plant scenarios, a 1300 MWt high temperature advanced nuclear reactor concept is adopted as the building block fission heat source for the plants in each of the three shipyard manufactured scenarios.[6] A steam (Rankine) cycle is assumed for the power cycle. The large FPSOs envisioned for Scenarios 1–2 employ two of these fission block plants; the smaller FPSO proposed for Scenario 3 requires one. Consideration of commercial shipyards for improved delivery of advanced nuclear energy systems is not unique to this study, as reflected in public reporting [25].

Proprietary cost estimates from 2019 are used in this study for calculation of target levelized costs for the relevant products in Scenarios 1–4: ammonia for marine shipping, synthetic jet fuel, desalinated water, and electricity. Cost estimates are courtesy of an advanced reactor technology developer for a 1075 MWt (500 MWe) reference nuclear heat source.[7] The $120 million and $80 million overnight capital cost (OCC) figures for the 1200 and 600 MWe nuclear fission heat sources, respectively, reflect a cost buildup based on 2019 commercial cost estimates from a top-tier South Korean shipyard and a major fabricator/supplier familiar with the power industry (Table 3). These costs included detailed design for all structures, systems, and components.

6 The 1300 MWt plant is assumed to operate with a net efficiency of 46.5% for a high temperature non-light water reactor coupled with a Rankine power conversion cycle. This results in a 600 MWe plant.

7 The reference plant is based on shipyard-manufactured plant designed and constructed by a major South Korean commercial shipyard.

Due to the specific advanced reactor design configuration and associated operations and maintenance (O&M) model, the fission heat source OCCs do not include the primary reactor system and nuclear fuel costs, which are treated as consumables with specified capital periods and interest rates; therefore, these costs are captured in O&M and levelized costs of production.

These estimates are not firm commercial quotes and should not be interpreted as such. However, they do indicate the potential for substantial reductions in construction costs by transitioning from traditional land-based construction models to a marine platform that can benefit from the controlled engineered environment of the modern large commercial shipyard. EPRI has adopted these estimates in its analyses as target costs for advanced nuclear energy systems corresponding to Nth-of-kind production via a manufacturing-based construction model.

To calculate equivalent OCCs for comparison with land-based nuclear plant cost estimates, the total nuclear plant is assumed to comprise the fission heat block, the power block, and the balance of hull. To account for the treatment of the reactor primary system and reactor salt as consumables, the annualized costs (Table 3) are summed over the 30-year design life to yield total costs on a per kWe basis. The resulting OCC equivalents and totals are presented in Table 4. Reactor nuclear fuel costs are considered in O&M costs and are not included in capital cost estimates.

Table 3. Cost breakdown for nuclear heat supply system for scenarios 1 – 3

	Scenarios 1 & 2: 1200 MWe* (2600 MWt)	Scenario 3: 600 MWe* (1300 MWt)	Unit	Basis
FPSO Nuclear Heat Source Block Cost	120	80	million USD	overnight capital cost
Balance of Hull and Power Block	740	500	million USD	overnight capital cost
Annualized Reactor Primary System Cost	34	23	million USD/y	4-year capital period; 7% interest rate
Annualized Reactor Fuel	60	39	million USD/y	16-year capital period; 7% interest rate
Annualized Reactor Salt	2.3	1.5	million USD/y	16-year capital period; 7% interest rate

*Scaled from a 500 MWe (1075 MWt) reference design with 46.5% conversion efficiency to 600 MWe (1290 MWt) and 1200 MWe (2580 MWt) plant outputs.

Table 4. Estimated equivalent nuclear plant cost (USD per kWe-basis) assuming 30-year operating lifetime.

	1200 MWe Nuclear Plant Capacity	600 MWe Nuclear Plant Capacity	Unit
FPSO Nuclear Heat Source Block Cost	120	80	million USD
Balance of Hull and Power Block	740	500	million USD
Annualized Reactor Primary System Cost	1000	690	million USD
Annualized Reactor Salt	69	45	million USD
Total‡	2000	1300	million USD
Estimated Capital Cost Equivalent‡	1600	2200	USD/kWe

‡Reactor fuel is captured under O&M costs.

Total estimated OCCs are $2200/kWe for a 600 MWe plant and $1600/kWe for a 1200 MWe plant. These figures indicate that swapping land-based nuclear plant construction for an FPSO-based deployment model offer potentially substantial reductions in the cost of nuclear plant construction.

These costs are a fraction of those for traditional GWe-class LWR projects in the West (for example, $5600/kWe median OCC from Figure 7[8]) and may appear unrealistically low. However, such cost reductions can be understood in terms of the fundamental shift away from nuclear construction practice to that of a fully controlled and engineered environment provided by the modern shipyard.

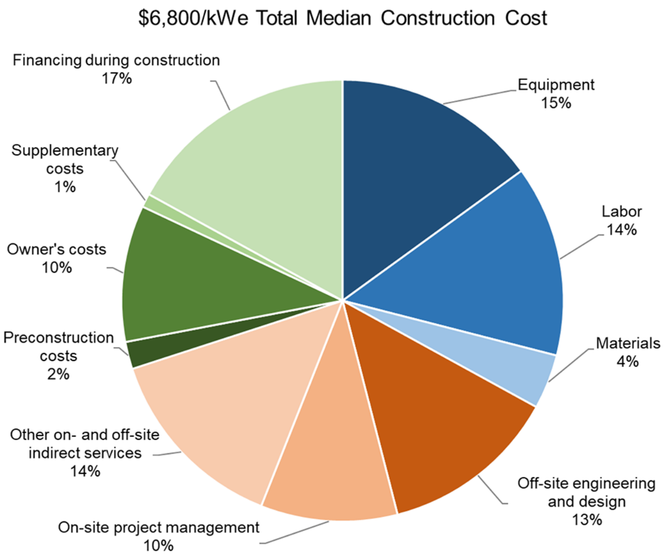

*Figure 7. **Cost breakdown for construction of a conventional nuclear power plant in the United States.** Cost estimates are derived from 1986 ORNL EEDB and 2017 EIRP reports [27, 28].*

Minimization or elimination of many soft costs that dominate land-based nuclear construction, including project management and engineering, and halving of labor costs reduces the familiar *nuclear pie chart* shown in Figure 7 to 61% of its original size, corresponding to $2600/kWe. It is also worth noting that nuclear OCC values in the $2000/kWe range have been reported for construction projects in South Korea ($2021/kWe) and China ($1807/kWe and $2615/kWe) [26]. Therefore, while OCC costs for FPSO-based nuclear deployment in the $1600 – $2200/kWe range appear aspirational at present for the West, these figures are not without precedent or basis.

Nuclear Heat Source for Land-Based Hydrogen Gigafactory Scenario

The conceptual land-based hydrogen production gigafactory proposed in Scenario 4 assumes a smaller 600 MWt nuclear heat supply system. For this aspirational concept, the high temperature nuclear heat sources are directly coupled to the hydrogen production plant to take advantage of a high efficiency thermochemical process assumed to be commercially mature for 2050 deployment at scale.

8 The $6800/kWe median construction cost for a GWe-class LWR presented in Figure 7 corresponds to an OCC of $5600/kWe after subtracting financing during construction costs.

3 Deployment Architecture

Before presenting the four zero-carbon fuel and commodity production scenarios, a high-level description of the enabling deployment model is provided below. This includes an overview of open architecture design and delivery and incorporation of shipyard manufacturing, as well as description of the components and systems common among the scenarios.

3.1 Open Architecture Design and Delivery

Each scenario in this study applies a set of modules, with a common interface architecture, configured to deliver a specific product. This approach is referred to as open architecture – defining the systems that configure functional modules that include heat source, power conversion, hydrogen generation, air separation, condenser, ammonia synthesis equipment, syngas generator, thermal desalination, and other preassembled systems. Not only are these modules functionally distinct, but they can be manufactured independently and then brought together for assembly into the final structure. Modules can be designed once and used in multiple configurations because the architecture specifies and standardizes the interfaces between them. Each module's design envelope allows for flexibility whereby, for example, different advanced reactor technologies could be used in the heat source module. Integrators work with component suppliers to build completed functional modules. Once modules have passed inspections and quality checks, they can be assembled into the final plant configuration.

Open architecture enables a range of products, specifying interfaces and interconnection standards but leaves open the specific means of achieving the functionality of each module. This means that the equipment that goes into modules and even the arrangement of equipment inside modules can be proprietary but the standards that modules must meet are open and visible to all. This is similar to how PC-based computer systems, Android™ phones, and other high performance, and low-cost systems have evolved. The International Association of Oil and Gas Producers (IOGP) initiated a similar approach through the Joint Industry Programme 33 (JIP33) in 2016 to standardize the specifications used for equipment procurement. The objective is to drive a structural reduction in project costs and schedules by enabling supply chains to become better, faster, and cheaper [29].

Even products that have not moved to a full *open architecture* paradigm–such as automotive manufacturing, combined cycle power plants, photovoltaic systems, and aircraft–have adopted some key aspects of open architecture as they have scaled up in volume and achieved broader market adoption. *Open architecture* should not be confused with *open source*—an approach primarily used for software development—as it is profoundly different. Open source products do not contain proprietary intellectual property; therefore commercial developers and vendors have limited incentive to invest in product improvement except for special circumstances. Successful application of open source model for hardware projects outside of the electronics industry has not been demonstrated. In contrast, an open architecture approach is well-suited for deployment of construction projects for both shipyard assembly of fully fabricated plants floated to final end-use locations and land-based plants designed for factory-based assembly at or near the final deployment site.

3.2 FPSO Delivery Model

Scenarios 1-3 employ the shipyard model for construction and delivery of the production facility, which is a floating ship-based structure. In this model, all components and equipment are delivered to dedicated manufacturing areas of the shipyard where they are integrated into their respective modules to comprise independent FPSO platforms. Serial construction of FPSO vessels described in Section 4 would take place in a modern, large, well-equipped shipyard. Top-tier shipyards in Korea, Japan, China, and Singapore are capable of and are currently constructing such vessels [30]. In a peak year, FPSO construction awards can exceed 20 [31].

The FPSOs would be fully assembled, tested, and inspected in the shipyard and subsequently towed to their final destination. Figure 8 depicts three FPSOs in dry dock at different stages of completion. This graphic illustrates the shipyard block construction technique where large sections (blocks) are constructed on site, complete with all necessary systems and subsystems, and sequentially added to the hull from end-to-end. In the foreground, a pre-assembled block awaits attachment to a hull under construction. The image also shows a finished hull ready for outfitting with ammonia production equipment (center) and a completed FPSO ready for commissioning (upper right). Heat and power generation equipment is installed below deck and production facilities are fitted on the open (weather) deck to minimize fire and explosion risk.

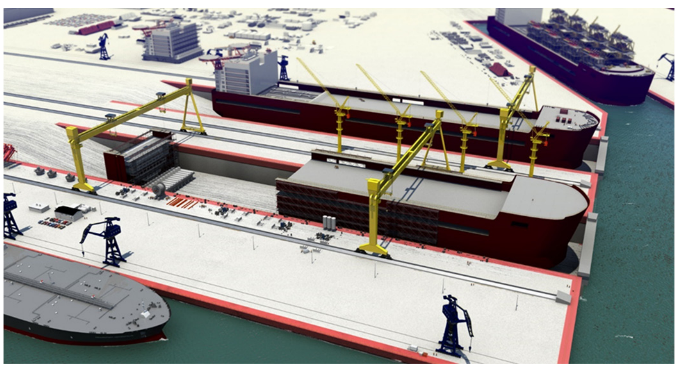

Figure 8. Ammonia FPSO production platforms being assembled in shipyard. In the foreground, a pre-assembled block section (module) is being moved into position to be attached to a hull which is under construction. The image also shows a finished hull ready to receive ammonia production equipment and, in the top right, a completed FPSO ready for commissioning. Graphic courtesy of LucidCatalyst; used with permission.

The commonality of equipment comprising modules enables much higher volume manufacturing, as each supplier has the potential to sell into a broad range of plants. This, in turn, enables those suppliers to make investments in automation, design their products for low-cost fabrication, negotiate higher volume purchasing of sub-components, and realize other cost reduction strategies.

Global fuels markets, including those identified in this report, represent a significant opportunity for the types of plants presented here. This scale combined with the rate of production that would be necessary to satisfy a small fraction of these markets, requires a radically different delivery architecture. The open architecture approach described above, based on shipyard manufacturing best practices, is a conceptual demonstration of an approach that, in principle, could deliver these projects at global scales.

3.2.1 Common FPSO Systems and Components

Several major systems and components are common to multiple scenarios (Table 5). To avoid repetition in describing each system for each scenario, they are briefly described here.

Hull and Mooring

As mentioned above, the FPSO production facilities are based on the physical dimensions of the Petronas PFLNG 2 hull (393m long, 64m wide, and 31m deep) [32]. The basis for the power generation systems layout is based on a conceptual design of a 600MWe shipyard manufactured power plant (169m long, 67m wide, and 30m tall) [30]. A PFLNG 2-sized hull is large enough to accommodate two of these. The heat sources and power systems are housed inside the hull, along with storage repositories for the liquid products. All processing equipment primarily sits on deck. The turret used to anchor the ship is expected to be less expensive and complex than the one used on FPSOs like the PFLNG 2 as the multiple connections to subsea gas and oil production equipment are not necessary for the application. The turret is located in the FPSO bow and allows it to weathervane—turning to face the prevailing wind and wave direction and better withstand extreme weather conditions. Each FPSO vessel may be sited at shore in a dredged harbor; moored near shore leveraging natural and engineering physical barriers to limit accidental and deliberate approaches by submerged and surface vessels; or further offshore with appropriate protective measures in place.

Advanced Nuclear (Fission) Heat Source

Many advanced fission heat sources under development have outlet heat temperatures in excess of 500°C, which are higher than conventional LWR outlet temperatures (~300°C) and support higher power generation and cooling efficiencies. The high-temperature heat sources required for applications considered in this study could be satisfied by a range of advanced reactor designs, including high-temperature gas-cooled reactors (HTGRs), sodium-cooled reactors (SFRs), or different molten salt reactor (MSR) concepts – similar to those being developed by companies such as TerraPower, Terrestrial Energy [33], Kairos Power [33], ThorCon [34], and Moltex [35]. These and other concepts could in principle serve as the basis for the generic, illustrative heat source used in the scenarios described below.

Table 5. Common modules among deployment scenarios

	Deployment Scenario	Hull and Mooring	Heat Source	Electric Power	Hydrogen Generation	Synfuel Production	Desalination Equipment
1	Ammonia to Fuel Marine Shipping Industry						
2	Producing Commercial Airline Fuel at Scale						
3	Power, Ammonia, and Desalinated Water Production						
4	Blending H2 into Existing Gas Network						

Electric Power Generation

For the three FPSO scenarios, all reactor thermal output is converted to steam, most of which is directed to steam turbine generators for electricity power in all the scenarios. Some of the high-temperature steam from the steam generators is diverted for preheating the steam going into the high-temperature electrolysis (HTE) units for greater conversion efficiency of electricity to hydrogen. The production of hydrogen is the most energy intensive process in all scenarios.

The standard nuclear plant block in Scenarios 1-3 comprises two reference 600 MWe fission reactors coupled to a steam-turbine driven generator, with the option of diverting steam to feed multi-effect distillation (MED) units for producing the high-quality distilled water required for electrolysis. The power generation system also supplies house electricity for FPSO operations. Back-up generators provisioned onboard would accommodate offline periods for the nuclear plant, such as for maintenance, or other loss of power events.

Hydrogen Generation

A variety of electrolytic hydrogen generation technologies are available and many more are in development. Conventional low-temperature electrolysis is a commercial technology, albeit usually deployed at megawatt scales, typically 2 MW per unit. These low-temperature electrolysis units use electricity as their only energy input and produce hydrogen at low pressure.

High-temperature steam electrolysis (HTSE) is assumed for all three FPSO scenarios as it consumes less electric power than conventional electrolysis and leverages high outlet temperatures of advanced reactors for high temperature steam production [36-38]. Commercialization of HTSE electrolyzer technology is being actively pursued by multiple firms; therefore, all three FSPO scenarios proposed herein assume commercially availability at the required scale at the time of deployment [39-41]. An important requirement imposed by the use of electrolysis is an adequate supply of high purity water as a feed stock.

High-temperature heat sources—featuring outlet temperatures above 500°C—also enable use of more direct and efficient hydrogen production approaches. The published literature identifies over 300 potential thermochemical cycles for thermo-chemical hydrogen generation [42] and several have received substantial development. However, no thermochemical technology is currently commercially available. Accordingly, this option is reserved for the more aspirational approach in Scenario 4.

Synfuel Production

The FPSO deployment scenarios described herein all produce some form of zero-carbon liquid synthetic fuels (abbreviated as synfuels). For this study, synfuels are proposed as carbon-neutral or carbon-negative fuels that can be used in existing fuel infrastructure with minimal changes or disruption to business models and consumer behavior. Ammonia (NH_3) production is featured in two scenarios, while the third FPSO-based scenario features synthetic jet fuel (Jet A) production. The proposed use of ammonia as a zero-carbon fuel substitute for marine propulsion requires adoption of compatible internal combustion engine technology. The carbon-neutral production of synthetic Jet A, however, represents a true drop-in substitution requiring no technology or behavioral changes on the consumer end. The ammonia and synfuel synthesis processing equipment are located on the FPSO's decks, with storage of the fuel products located in the FPSO's berth.

Ammonia has been traditionally used in fuel refinement and as a fertilizer feedstock; however, it has become increasingly recognized as a stable hydrogen (energy) carrier and viable liquid fuel for applications like marine shipping [43, 44]. Producing ammonia requires combining separate hydrogen and nitrogen streams typically via the Haber-Bosch process. The hydrogen is produced by HTSE, and the nitrogen is pulled from the air using an air separation unit (ASU). The Haber-Bosch process uses high temperatures, high pressures, and a metal catalyst to combine hydrogen and nitrogen to make ammonia.

Jet fuel synthesis on the FPSO is fed by hydrogen and carbon monoxide gas-streams. Hydrogen and carbon monoxide are generated via an electrolyzer operating with solid oxide electrolysis cell-stacks for the high-temperature co-electrolysis (HTCE) of CO_2 and H_2O. Limestone ($CaCO_3$) is assumed as the feedstock for generation of carbon dioxide via calcination; however, other sources of concentrated CO_2 could be utilized as well. The limestone is delivered to the production ship and heated in an on-board calciner to approximately 900°C to yield lime (CaO) and CO_2– the latter of which provides the carbon feedstock for producing carbon monoxide. After co-electrolysis, hydrogen and carbon monoxide are then sent through a Fischer-Tropsch process unit to yield liquid hydrocarbons.

At the end of the process, the byproduct lime is available to re-absorb CO_2 from the air or seawater, offsetting CO_2 emissions from combustion of the synthetic fuel [45]. If the lime (CaO) is dispersed and dissolved in the ocean, the resulting reactions result in greater CO_2 consumption than is released in the calcining process, yielding a net negative carbon footprint for the use of Jet A or any other synfuel produced via this route.

Desalination Equipment

Purified, desalinated water produced by the established thermally driven, multiple effect distillation process is incorporated into all scenarios for multiple applications. These include supplying sufficiently pure water for use of electrolyzer technology for providing hydrogen feedstocks, fresh drinking water for FPSO staff, and for delivery onshore as an end-product itself. All FPSOs and the onshore hydrogen gigafactory feature relatively large, thermally driven desalination plants that can utilize low-grade heat from heat sources and power cycles [42].

The desalination unit heats sprayed seawater onto a hot surface, typically pipes, to make steam, which heats the next batch of seawater (and ultimately condenses to make freshwater). This desalination technology—multiple-effect or multistage desalination system (MED for short)—was chosen for its simplicity, ability to use relatively low temperature heat, and avoidance of membrane replacements required for reverse-osmosis systems.

3.2.2 Common FPSO Scenario Considerations

FPSO Permissions and Lifecycle Operations

Deploying an offshore synthetic fuels plant requires a wide variety of skills for design, construction, financing, and operation of FPSO-based facilities. A team comprising experts in marine, nuclear, and chemical engineering would likely be assembled by a responsible entity with ties to or familiarity with the proposed host nation. The nuclear heat source design would also need to be permitted/licensed for offshore operation by competent authorities ensuring, among other things, nuclear safety, security, and safeguards. Provisions for managing the full lifecycle of the nuclear heat source will be important upfront considerations, including reactor refueling, irradiated fuel storage, and end-of-life decommissioning of the nuclear plant and any radiologically controlled elements of the hull.

One or more demonstrations may be needed to de-risk the deployment model sufficiently for regulator and investor confidence in a novel, multi-billion-dollar enterprise. Long-term offtake contracts for products, such as ammonia, hydrogen, electric power, could further incentivize and facilitate investment for deployment at scale.

FPSO Personnel, Crew, and Accommodations

Separate security, marine, nuclear, and chemical process crews would be needed to ensure focused expertise in all critical areas for the three FPSO-based scenarios. An adequately sized accommodation block would be needed to house the day and night crews. Crew quarters on the Petronas PGLNG 2 can house approximately 150 people [32]. It is assumed that all FPSO hulls can host a sufficiently sized accommodation block scaled to fit larger operations staff if required. Consistent with round-the-clock operations on safety-critical offshore energy production platforms, crews are assumed to work 12-hours-on-12-hours-off shifts on a 2-weeks-on-2-weeks-off schedule. High-bandwidth communications to shore allow specialists to interact with the offshore crew to optimize staffing. It is envisioned that many engineering, administrative, and training functions can be met with onshore staffing. Limited, controlled access afforded by offshore location and ship-based platforms, reduced onboard security staff may be required to repel unauthorized boarding attempts.

Four-shift staffing requirements for a 1 GWe-scale onshore advanced nuclear plant have been estimated in the range of 200 staff [46, 47]. Based on the operational strategies outlined, it is assumed here that an FPSO-based power plant staff can be reduced by over 50%. This includes crew capacity for oversight of hydrogen generation and downstream production operations. Space and accommodations from additional staffing and equipment/rigging is also anticipated during refueling and scheduled maintenance operations. One important attribute of the advanced heat sources assumed for all scenarios is that safety is achieved primarily through inherent physics and design; one potential benefit is the accompanying opportunity for reduced staffing for many routine monitoring, control, and maintenance activities.

Global FPSO Assumptions

Many key assumptions have significant influence on cost estimation. In this study, a number of global assumptions are made to facilitate estimation and calculation for all three FPSO scenarios. Because FPSO production is assumed to occur entirely in established, efficient, top-tier shipyards, standard EPC-related fees and premiums associated with land-based construction are not included. The FPSO scenarios are assumed to be Nth-of-a-kind (NOAK), standardized, serialized deployments and therefore do not include first-of-a-kind (FOAK) costs such design work, shipyard mobilization and equipment upgrades, and reactor specific certification/licensing. Financial assumptions include a 30-year lifetime for each FPSO, a 7% weighted average cost of capital (WACC), and exclusion of income taxes. Addition scenario- and technology-specific assumptions are called out in the respective scenario discussions in Sections 4 and 5.

3.3 On-Site Plant Delivery Model

A second, land-based delivery model features on-site manufacturing to achieve the required efficiency and scale. For this delivery model, (1) equipment is delivered to the heat-source factory—the gigafactory—which is at or near the deployment site; (2) the equipment is assembled and delivered by crane to module housings comprising prefabricated concrete and steel components that have been assembled and installed at the host location.

In contrast to shipyard-based models which exclusively leverage existing facilities and substantial investments in automation, workforce training, quality systems, and supply chain capacity, establishing the on-site gigafactory delivery model will require significant new investment of capital and other resources for on-site heat-source fabrication. Consequently, the applicability of this approach is likely limited to situations involving very large-scale projects spanning many years or decades. Figure 9 depicts a conceptual layout for an integrated on-site manufacturing model for a multi-GW-scale hydrogen production facility for blending hydrogen into an existing natural gas supply network. This scenario is described in detail in Section 5.

Figure 9. Perspective highlighting the integration of on-site fabrication, assembly, deployment, hydrogen production, and product delivery in a single hydrogen gigafactory. *On-site equipment assembly and modular civil works fabrication appear in upper left-hand corner. As nuclear heat source/reactor units and other systems are completed, they are moved via cranes into position in the reactor farm (center) for below-grade installation of heat sources and their companion heat exchanger modules (blue and green hatches) and to the hydrogen production yard (center right). Hydrogen is injected at pressure into the existing natural gas network via underground piping that connects from the hydrogen production facility to compressor stations (black-roofed structures lower center). Graphic courtesy of LucidCatalyst; used with permission.*

4 FPSO-Based Carbon-Neutral Fuel and Commodity Production Scenarios

The three FPSO-based scenarios are evaluated in this section to illustrate how innovative deployment models for new technology configurations can serve non-electricity markets, displace fossil fuels for hard-to-decarbonize sectors such as transportation, and provide sufficient market pull to enable serial nuclear manufacturing for greater cost competitiveness. The associated preconceptual designs are meant to highlight potential market opportunities, deployment models, and benefits to producers (owner-operators) and consumers. The three scenarios are described using point estimates of costs derived from credible, publicly available information when available and privileged information when needed. These estimates are used to calculate levelized costs for production of commodities of interest for each scenario. These point estimates are provided for illustration only and are subject to uncertainties not addressed within the scope of this study.

4.1 Scenario 1: Production of Ammonia for Marine Shipping Fuel

Scenario 1 describes the use of an FPSO dedicated to producing carbon-free ammonia fuel for the global marine shipping industry.

4.1.1 Overview

Marine shipping is responsible for delivery of more than 80% of global trade and represents one of the most difficult transportation sectors to decarbonize [48]. In April 2018, the International Maritime Organization (IMO) declared its ambition to reduce the sector's total annual greenhouse gas emissions by at least 50% by 2050 compared to 2008 levels [49]. Near-term activities include imposing new international standards and regulations [50] for sulfur content in fuels; however, global freight demand is expected to triple by 2050 [50]. Achieving the IMO decarbonization targets will require a systematic shift to new fuels, such as hydrogen-based zero-carbon fuels like ammonia (NH_3).

National and commercial RD&D efforts are underway to design new marine engines and retrofit existing engines that would allow them to run on carbon-free ammonia. Japan has spent several years developing ammonia-burning marine engines and one of South Korea's largest shipbuilders, Daewoo Shipbuilding and Marine Engineering (DSME), announced plans to expand its technology and business offerings to engineering ammonia propulsion systems for marine ships [51]. MAN Energy Solutions, a major manufacturer of marine propulsion systems, has reported development efforts for engines that run on ammonia [52]. In January 2020, MAN joined three of the world's largest companies in the maritime industry—Samsung Heavy Industries, Lloyd's Register, and MISC Berhad—on a joint project to design an oil tanker fueled by ammonia [53]. Concurrently, the Norwegian firm Equinor signed an agreement with NCE Maritime Cleantech, Eidesvik Offshore, Wärtsilä Corporation, and Prototech to convert one a supply vessel to operate on carbon-free, ammonia-powered fuel cells [54].

For the purposes of this study, ammonia for zero-carbon shipping represents a well-defined market to potentially drive FPSO-based deployment at scale in the future. Support for this scenario is based on observations that include:

- Documented commercial efforts to advance ammonia-fueled marine transport
- A well-established multi-billion-dollar global market for ammonia
- Existing global transportation and storage infrastructure for ammonia

FPSO-Based Ammonia Production

Scenario 1 assumes that ammonia production onboard the FPSO would use the Haber-Bosch process, which combines nitrogen (separated from air by cryogenic or membrane-based methods) and hydrogen produced using HTSE. Dimensions, equipment list, process design, and cost bases for hydrogen generation via HTSE are derived from a 2003 cost study [55]. Figure 10 depicts the proposed ammonia production process.

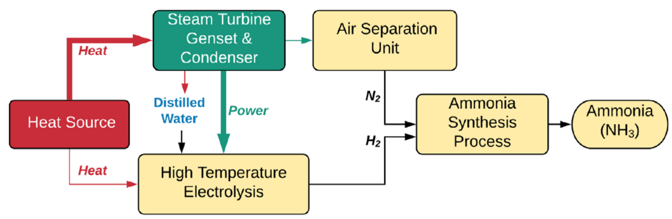

Figure 10. Ammonia production process

While there are intensive efforts to develop an alternative, more compact technology that operates at lower temperatures and pressures for generating hydrogen, the production of hydrogen by electrolysis will likely remain an important energy intensive step for ammonia production using electricity.

The absence of carbon in the production of ammonia eliminates the need for CO_2 supplied either as an external feedstock or captured in situ from the air or seawater, simplifying process design and overall implementation compared to the production of synthetic hydrocarbons. Likewise, the absence of carbon in the combustion of ammonia also avoids carbon emissions.

While NOx emissions are a concern for ammonia combustion, existing selective catalytic reduction (SCR) technology is available for effective NOx emission control.

FPSO Power Capacity and Annual Ammonia Production

To produce ammonia at the rate of 3,600 tonnes/day for a reference plant, the FPSO-based facility needs to generate 7.4 kg/s of hydrogen, requiring 0.9 GW of electricity and approximately 0.3 GWt of thermal energy. Table 6 summarizes FPSO production potential and physical specifications for Scenario 1.

Table 6. Ammonia production potential and physical specifications

Ammonia Production Potential	
Thermal capacity (MWt)	2,600
Electric capacity (MWe)	1,200
Annual H_2 production capacity (tonnes)	220,000
Annual NH_3 production capacity (tonnes)	1,200,000
Daily NH_3 production capacity (tonnes/day)	3,300
Daily NH_3 production capacity (BOE/day)	12,000
Physical Specifications	
Platform dimensions (m)	L: 393; W: 64; H: 105; Draft: 13
Lifetime (years)	30
Displacement (tonnes)	152,000

A much smaller electrical demand is imposed by other onboard processes including air separation, compression, and general house loads. An appropriately sized air separation unit requires approximately 180 kWh per tonne of nitrogen produced, which is equivalent to 20 MWe [56]. As a conservative estimate, nuclear plant capacity for generation of 1,200 MWe is assumed for Scenario 1.

A PFLNG 2-sized vessel features 25,000 m^2 of plan area (390m x 64m) [32], and equipment can be placed both below and above decks. Detailed design of the FPSO and its subsystems is beyond the scope of this study, but conceptual layouts indicate ample hull space. Similarly, equipment weight is anticipated to represent a fraction of the total hull capacity.

Once moored at its production location, near a suitable diversity of markets, the FPSO can produce ammonia, which is then stored as a refrigerated liquid and offloaded on smaller, ammonia transport tankers and/or ships. Figure 11 depicts an ammonia tanker preparing to receive ammonia and highlights the multiple ammonia synthesis processing units on deck.

Market Opportunity

The world uses 170 million metric tonnes (Mt) of ammonia each year [57], corresponding to a global market of approximately $50 billion [58]. Ammonia is primarily used for fertilizer feedstock (~80%), while the rest is used for refrigerant gas, water purification, and the manufacturing of plastics and chemicals. Although the existing global ammonia market is already substantial, using ammonia to fuel marine shipping would dramatically increase the size of the market.

Figure 12 highlights the current and potential demand for ammonia, with the projection of additional demand associated with replacement of marine fuels for global shipping. It also highlights the amount of capacity (GWe) required to make such quantities of ammonia.

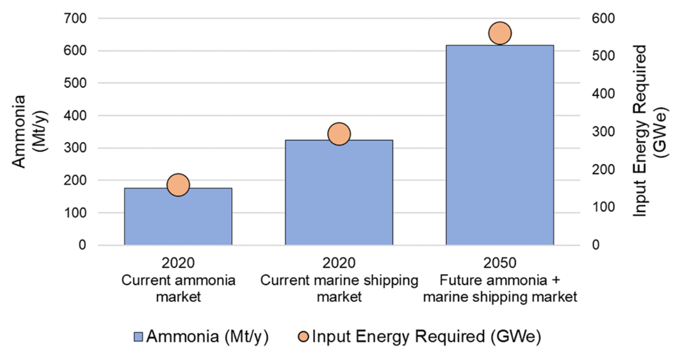

Figure 12. Current and forecast ammonia market potential and energy requirements (GWe) [54, 56]

Figure 11. Scenario 1 – FPSO platform preparing to offload ammonia to tanker for delivery to point of use or subsequent distribution

The current global shipping fleet consumes three million barrels of fuel oil per day [35]. This demand is equivalent in energy to 324 million tonnes of ammonia per year–representing a potential $100 billion market opportunity based on ammonia prices in the range of $200–300/tonne ($9–13/GJ) [59, 60].[9, 10] For comparison, the price of low sulfur fuel oil (LSFO) varied between $300 – 600/tonne ($7.30–14.50/GJ, LHV) over the five-year period from 2015 to 2019, placing carbon-free ammonia production costs within the range of LSFO costs [61]. This suggests that additional costs associated with ammonia handling, transport, and storage could be competitive with respect to existing fuel pricing and decarbonization of the shipping sector.[11] Moreover, as prices fall withing range of global ammonia prices, an FPSO producer could also choose to profitably sell into the global commodity market.

Assuming a nominal large-scale ammonia plant output of 3,600 tonnes/day [62], 324 plants of this size would be needed to meet the current fuel needs for the marine shipping industry via ammonia substitution. And by 2050, ammonia production would need to double (to 617 plants) to meet projected increases in maritime traffic [55]. Capturing even a fraction of this market would provide a significant market opportunity to drive serial nuclear manufacturing and deployment.

In terms of carbon footprint, global shipping emits 2% of all global CO_2 or 750 million tonnes of CO_2 equivalent [63]. If carbon-free ammonia were made available at prices competitive with carbon-based fuels such as LSFO, conversion to ammonia-fuel propulsion could provide an economical and scalable solution for decarbonizing marine transport. The market for ammonia as a carbon-free fuel could extend beyond the marine shipping sector into electricity generation, and combustion turbine technology is under development for burning ammonia or an ammonia-hydrogen mixture.

4.1.3 Producer Perspective

Producing ammonia via the FPSO deployment model in Scenario 1 offers a number of potential benefits for the producer. First, the FPSO can be sited relatively close to major global ship refueling depots and relocated to serve multiple locations, as allowed by legal, licensing, and market conditions. The FPSO deployment model can leverage the productivity, quality, and learning of shipyard manufacturing and avoids the uncertainties and costs associated with land-based siting, such as seismic issues. Furthermore, proximity to an ultimate heat sink—the ocean—represents a substantial benefit of this deployment model.

As this fleet of FPSO's can in principle be very similar in design, with different classes for specific climate and metocean conditions, construction costs may decrease over time as has been seen with repeat builds of conventional FPSO and other types of ships, and skilled operators will be able to transfer from ship to ship. Producers could also hedge the marine shipping fuel market while accessing other large ammonia markets (fertilizers, ammonia fuel cells, etc.)

9 Assuming each liter of oil contains 41 MJ (HHV), consumption at 3 million barrels/day equates to 20 billion MJ/day of energy. The energy density of ammonia is 22.5 MJ/kg, which means the equivalent consumption of ammonia would be 890 million kg/day or 320 Mt/year.

10 The relevant conversion factor is 22.5 GJ/ tonne ammonia. The average market price for ammonia from 2018-2019 was $500/tonne.

11 Note that some shipping is being converted to LNG, which will be a more expensive conversion but a lower fuel price, $6-8/GJ, and still emits about 50% of the CO_2 of traditional heavy fuel oil.

4.1.4 Customer Perspective

Customers of carbon-free ammonia would benefit from a scalable, cost-effective path to meeting decarbonization targets. Siting of production FPSOs near existing global refueling locations would avoid the need for special routing. And given the potential flexible deployment of production where, when, and at quantities needed, global FPSO-based ammonia supplies for marine fuel could lead to more stable global market prices for all markets and applications.

Carbon-free ammonia can potentially enable greater market access for shipping companies that need to comply with port carbon regulations and reporting requirements. Access to low-cost ammonia storage combined with on-demand hydrogen reforming could also increase fuel security and enable relatively low-cost, zero-carbon dispatchable electricity generation and non-electric energy end-uses.

4.1.5 Indicative Economics

The OCC estimates in Table 7 are sourced primarily from a 2010 Idaho National Laboratory study that included evaluation of the cost for an integrated ammonia production facility powered by a high-temperature gas reactor. Multiple configurations were evaluated in the INL study, and results suggested that 4 x 240 MWe reactors could produce 3,360 tonnes of ammonia per day [64]. Appendix A provides additional key sources utilized for cost estimates.

Ammonia Synthesis

Ammonia production in Scenario 1 depends heavily on the cost of hydrogen and the capital costs for air separation equipment and the ammonia synthesis plant. The costs below have been escalated to 2019 USD and scaled linearly to the 3,600 tonnes/day production rate assumed for this scenario. Table 8 provides a breakdown of the costs and assumptions that derive a levelized cost of ammonia of $230/tonne ($10/GJ, LHV), coming in just above 2019 pre-shipment ammonia prices of $200/tonne ($8.90/GJ, LHV) per Table 2 above.

Ammonia synthesis requires hydrogen (18 wt.%) and nitrogen (82 wt.%). Production of hydrogen via electrolysis dominates electric power requirements for ammonia synthesis. Nitrogen generation by cryogenic air separation units (ASUs) consumes less than 1% of total power requirements, while the ammonia synthesis process itself consumes approximately 2-3% [64, 65].

Hydrogen Generation

The reference HTSE process for hydrogen generation is based on a 2013 study. This HTSE process yields 1.9 kg/s of H_2 and consumes 240 MWe and 63 MWt of steam [55]. The resulting hydrogen cost estimate is $2.60/kg assuming $60/MWhe for electricity and $20/MWht for steam. Reducing OCC due to shared services and eliminating one-time engineering and contingency charges are assumed to provide a OCC reduction for this module of 35%. Adjusting cost of hydrogen calculation for an electricity cost of $24/MWhe and steam cost of $8/MWht yields a hydrogen cost of $1.10/kg. The modeled FPSO would need 7.35 kg/s of hydrogen: equivalent to approximately four of the reference HTSE plants [55]. For comparison, steam methane reforming in the United States with $3/MMBtu natural gas can produce hydrogen at around $1 per kg.

A recent IEA Greenhouse Gas Program study estimated hydrogen production costs of $1.40/kg from steam methane reforming with carbon capture and sequestration (CCS), assuming natural gas at $6.60/GJ ($7/MMBtu) [66]. Therefore, the estimated costs for FPSO-based production with nuclear heat/electricity presented in this study appear lower than H_2 from natural gas with CCS, once CO_2 transport and storage costs are included. The higher capital cost for the FPSO production platform versus a conventional ammonia plant can be offset by avoided natural gas costs (as fuel and feedstock) and the lack of CO_2 emissions.

Table 7. Estimated FPSO OCC for ammonia production

Ammonia Production FPSO Capital Cost	2019 USD
High temperature electrolyzer	$380,000,000
Nitrogen Generation (cryogenic air separation unit)	$48,000,000
Ammonia synthesis (Haber-Bosch) equipment	$290,000,000
Piping, instrumentation, electrical, and integration subsystems	$98,000,000
Subtotal, electrolyzer, N_2 generation, ammonia synthesis, and other subsystems	**$870,000,000**
FPSO nuclear heat source block	$120,000,000
Balance of hull and power block	$740,000,000
Subtotal, hull and power block	**$860,000,000**
Total OCC	**$1,700,000,000**

Table 8. Levelized Cost of Ammonia

Levelized Cost of Ammonia		2019 USD
Annual ammonia production (tonne)	1,200,000	
Capital cost, entire FPSO		$1,700,000,000
Capital period (years)	30	
Interest rate	7%	
Annualized capital expense		**$140,000,000**
Direct crewmember count on staff	500	
Annual expense per crewmember	$100,000	
Annual staffing expense		$50,000,000
Annual fuel and consumables expense		$94,000,000
Annual maintenance (2.5% of OCC)		$43,000,000
Annual administration, insurance, fuel operations, and decommissioning expense		$9,500,000
Total annual expense (USD)		**$340,000,000**
Levelized cost of ammonia (USD/tonne)		**$230**
Levelized cost of ammonia (USD/GJ)		**$10**
Levelized cost of ammonia (USD/BOE)		**$62**

4.2 Scenario 2: Production of Carbon-Neutral Commercial Airline Fuel at Scale

Scenario 2 describes the use of an FPSO dedicated to the synthesis of carbon-neutral (or carbon-negative) aviation fuel for the global commercial airline industry.

4.2.1 Overview

Commercial airmiles traveled are expected to nearly triple by 2050 from 2020 [67]. Efforts are underway to develop biofuel alternatives for jet fuel; however, the availability of arable land required to meet required production levels could present a major issue for scaling. Opportunities for direct electrification of long-distance and heavy-haul aviation are also limited by fundamental energy density limits for battery storage. Future consumer and policy demand for low carbon air travel represents a challenging and large opportunity for adopters and producers of cost-competitive, carbon-neutral fuel alternatives, such as synfuels. The Scenario 2 approach uses an offshore floating production ship equipped with high-temperature nuclear heat sources capable of powering all aspects of jet fuel synthesis from water and non-fossil-derived carbon feedstocks. This scenario uses limestone as a conveyable carbon source to establish a scalable, zero-carbon, commercial-grade jet fuel.

Liquid hydrocarbon fuels can be made from a gas mixture of hydrogen and carbon monoxide [68].[12] Such a gas mixture is generically referred to as *synthesis gas* and commonly known as *syngas*. Syngas can then be converted to liquid hydrocarbon fuels through the use of tailored catalyst-based chemical processes known collectively as Fischer-Tropsch synthesis, as shown in Figure 13 prior to the process output.

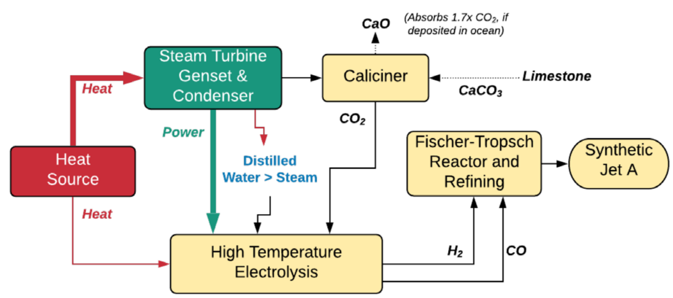

Figure 13. Synthetic Jet A aviation fuel production.

As in Scenario 1 for ammonia production, the FPSO platform is equipped with high-temperature electrolysis equipment. For jet fuel synthesis in Scenario 2, electrolysis equipment is again used but, in this case, is operated in co-electrolysis mode to generate (1) hydrogen from steam, and (2) carbon monoxide from CO_2.

Chemical synthesis of hydrocarbon fuel requires a source of carbon; in this scenario, that source is limestone or $CaCO_3$. To liberate CO_2, a calciner heats limestone ($CaCO_3$) to a sufficiently high temperature to evolve CO_2 gas, leaving behind CaO—also known as quicklime or burnt lime—as a byproduct. In traditional lime production, the CO_2 generated from this process represents either an unused byproduct and/or an undesirable greenhouse gas emission. Here, it represents a primary feedstock for a valuable product.

12 Syngas compositions vary by source, comprising 30 – 60% carbon monoxide (CO), 25 – 30% hydrogen (H_2), 0 – 5% methane (CH_4), 5 – 15% carbon dioxide (CO_2), and lesser amounts of water vapor, hydrogen sulfide (H_2S), carbonyl sulfide (COS), ammonia, and other contaminants [68].

Aside from its value as an agricultural or chemical commodity, the lime byproduct can be employed post-process to capture environmental CO_2 to yield either a net carbon-neutral or carbon-negative fuel. Depositing the lime in the ocean can result in carbon-negative combustion of jet fuel if this post-production step is executed and fully reflected in carbon accounting. Introduction of lime to seawater results in the net removal of 1.7 moles dissolved CO_2 for each mole of CO_2 released during combustion due to the carbonate-bicarbonate equilibrium chemistry per the following reaction [69]:

$$CaO + 2CO_2 + H_2O \rightarrow Ca^{2+} + 2HCO_3^-$$

The produced synthetic jet fuel represents a drop-in replacement and can be immediately introduced via the conventional distribution infrastructure. As a direct substitute, use of synthetic Jet A does not require any changes to equipment or business practices. Ongoing research and development efforts to optimize and commercialize these processes may further reduce energy and capital costs.

Scalable Jet A Production from Offshore FPSO

As with other scenarios described in this study, Scenario 2 envisions FPSO manufacturing in a top-tier shipyard, allowing for highly efficient fabrication and a high degree of automation for various labor-intensive tasks. For comparison, the hull for the largest FPSO produced to date, the 488m Shell Prelude, was constructed in less than 14 months [70]. Outfitting of the Prelude's processing equipment and major systems, such as gas plant modules and power supply systems, required an additional 19 months [70]. The vessel's maiden voyage took place 4 years and 9 months after the first steel was cut. Construction duration of the reference PFLNG 2 FPSO vessel was originally planned for 3 years from first steel cut to commissioning; however, low oil prices in 2016 caused Petronas to delay the launch until early 2020 [45]. The construction duration for an NOAK Jet A FPSO–particularly with process optimization, learning, and standardization–can be expected to decrease to three years in line with current practice. Table 9 summarizes FPSO-based Jet A production potential and physical specifications envisioned for Scenario 2.

Figure 14 shows a bulker carrier, a ship designed to carry unpackaged cargo, mooring up to the synfuel FPSO. The bulk carrier delivers crushed limestone to the FPSO and receives the calcination byproduct, lime (CaO).

Table 9. Synthetic Jet A production potential and physical specifications

Jet A Production Potential	
Thermal capacity (MWt)	2,600
Electric capacity (MWe)	1,200
Electrolyzer H_2 and CO daily production (kg/day)	5,000,000
Annual jet fuel production (tonne/year)*	510,000
Annual jet fuel production (bbl/year)*	4,000,000
Annual jet fuel production (BOE/day)*	9,600
Physical Specifications	
Platform dimensions	L: 393m; W: 64m; H: 105m; Draft 13 m
Lifetime (years)	30
Displacement (tonnes)	152,000

*Accounting for production capacity factor.

*Figure 14. **Scenario 2 — FPSO platform for production of synthetic Jet A with bulk carrier arriving alongside for delivery of limestone feedstock.** The bulk carrier (smaller vessel on right) drops off the limestone ($CaCO_3$) reagent and picks up lime (CaO) byproduct. Reagents and byproducts are stored in the hull of the FPSO close to the calcination equipment in the stern.*

Assuming a 29% all-in conversion efficiency from thermal energy to Jet A, the equivalent of 1,500 GWt (600 GWe) will be needed. Additional heat inputs equivalent to 140 GWt would be needed to calcine the limestone needed to supply the CO_2.

Crushed Limestone as CO_2 Source for Synfuel Production

Calcining of limestone by heating to approximately 900°C yields CaO and CO_2 gas. Much of the process heat can be recovered from the product stream and reused for preheating the incoming limestone. Approximately 5 GJ of thermal energy per tonne of generated CO_2 is needed to drive the reaction. As current advanced high-temperature fission reactor designs have outlet temperatures below 900°C (primarily due to materials limitations), additional electrical heating would be required to achieve the desired temperature, resulting in increased process energy requirements. Some of the waste heat may be employed for distillation or steam production and power generation. The reference Scenario 2 heat block generates 2600 MWt (1200 MWe), of which 75% is allocated to electricity generation (900 MWe) and 25% to process heat to support FPSO process operations. At this scale, the process can yield approximately 7 kg/s of H_2, which translates to 0.5 Mt (or 4 million bbl) of Jet A annually. More than 550 ships of this capacity would be needed to generate the world's current consumption of Jet A in Figure 16.

Combustion of synthetic Jet A releases CO_2 just like its fossil counterpart. To make this fuel substitution option truly carbon neutral, the byproduct CaO can be reacted with atmospheric CO_2 phase to reform limestone ($CaCO_3$), resulting in a 1:1 ratio of carbon sequestration to carbon emitted for a net zero carbon balance (Table 10). For a net carbon-negative fuel option, the byproduct lime can be dissolved in seawater to result in the net removal of 1.7 moles of CO_2 from solution per mole of CaO dissolved due to carbonate-bicarbonate equilibrium chemistry: $CaO + 2CO_2 + H_2O \rightarrow Ca^{2+} + 2HCO_3^-$. This means that for each molecule of CO_2 released during combustion of the synthetic Jet A product, marine-based dispersal of the lime byproduct provides a net reduction in environmental CO_2 by a factor of 1.7.

Figure 15 illustrates the bulk carrier depositing a slurry of lime into the ocean on its way back to shore.[13] The image also shows a liquid fuels tanker arriving to receive the synfuel and deliver it to the nearest Jet A fuel depot.

13 Introduction of byproduct CaO into the ocean for carbon sequestration and counter acidification benefits would require modification of or exemption from the current terms of the London Dumping Convention.

Figure 15. Bulk carrier depositing carbon-sequestering lime into the ocean as liquid fuels tanker arrives to collect synthetic Jet A from production platform. Graphic courtesy of LucidCatalyst; used with permission.

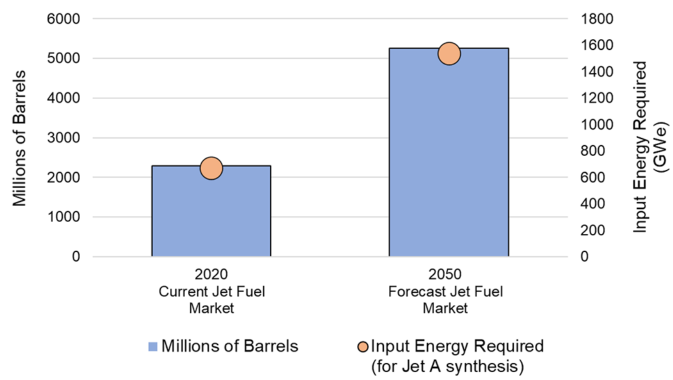

Figure 16. Current and forecast market value for Jet A and associated input energy requirements for synthesis [70–72]

4.2.2 Market Opportunity

The global Jet A market is large and expect to grow. According to the International Air Transport Association (IATA), the global airline industry spent $188 billion on fuel in 2019 [70]. On a volume basis, this is expected to grow by a compound annual growth rate (CAGR) of 1.4% through 2040 [71]. Over the past 10 years, jet fuel prices per barrel have hovered around $20 above the price for Brent crude oil per barrel.

As fuel demand grows, so too do the expected demands from policymakers and the traveling public to have greener airlines and air travel options. According to the Air Transport Action Group, air travel emitted 915 Mt CO_2 in 2019, about 2% of all CO_2 emissions produced by humans. IATA estimates that the industry consumed 96 billion gallons of jet fuel in 2019, a figure that has risen every year for the past decade [72]. This energy flow corresponds to an equivalent average thermal power of 420 GWt.

Table 10. Carbon-neutral and carbon-negative hydrocarbons production [45]

Fuel Type	CO_2 Source (Calcining Limestone)	Making Synthetic Hydrocarbons	Carbon Profile
Carbon-neutral	$CaCO_3$ + heat $Ca \rightarrow O + CO_2$ (This generates CO_2) ↑	1. Co-electrolysis of H_2O and CO_2 to produce syn gas ($CO_2 + H_2O \rightarrow CO + H_2 + O_2$) 2. Additional H_2 production (from HTSE) 3. Synthetic hydrocarbon production (syngas + synfuel process)	CaO absorbs CO_2 from the air (~1:1 emission to absorption ratio) ↔
Carbon-negative			CaO absorbs CO_2 from the ocean (~1:1.7 emissions to absorption ratio) ↓

4.2.3 Producer Perspective

Producing carbon-neutral or carbon-negative Jet A fuel provides several advantages for the prospective fuel producer. First, this allows the producer to offer a hedge to global oil prices and to provide the possibility of signing stable, long-term supply contracts. As costs fall, first mover suppliers can also take an increasing share in a massive growing global market. Because synthetic Jet A offers a drop-in fuel substitute, the supply chain does not need to change physical assets, practices, licensing, or safety approaches. Also, FPSOs can be positioned near key markets, and can potentially reduce distribution costs if sited close to major coastal fuel depots and airports. Since most aviation fuel is typically transported by a tanker at some point in the supply chain, the introduction of the FPSO deployment model in Scenario 2 does not introduce fundamental changes to the overall production model.

4.2.4 Customer Perspective

The availability of scalable, cost-competitive, carbon-neutral (or carbon-negative) jet fuel supplies would allow commercial airlines to offer passengers and freight customers a credible, affordable, sustainable path to decarbonized heavy duty air transportation. For the passenger and air freight carriers, the drop-in synthetic fuel option also minimizes required modifications of behavior, equipment, infrastructures, and business models.

4.2.5 Indicative Economics

Overnight capital cost estimates in Table 11 are derived from a number of sources. Hydrogen production costs are from a published 2010 Idaho National Laboratory study [64]. Additional costs are included for the calciner and synfuel processing equipment. The levelized cost of producing a barrel of Jet A, as shown in Table 12, is $82/bbl, which is competitive with recent a wholesale ten-year (2010-2019) average price of $94/bbl (from Table 2).

The cost of syngas production drives the cost of producing synthetic hydrocarbons, and the cost of syngas depends on the cost of sourcing or producing its constituents, predominately hydrogen, CO, and CO_2. Hydrogen is derived from water. The choice of carbon sources is particularly important. Carbon derived from CO_2 can be a relatively expensive source on a mass basis as it comprises just 27.3 wt.% of the feed material.

4.3 Scenario 3: Production of Carbon-Neutral Power, Ammonia, and Desalinated Water

Scenario 3 represents a variation on Scenarios 1 and 2, integrating the FPSO model and zero-carbon power and heat generation from nuclear with flexible poly-generation of electricity, ammonia, and desalinated water.

4.3.1 Overview

This poly-generation production facility is suited for near-shore deployment off major coastal population industrial centers. While product flexibility likely results in suboptimal performance, it does offer a unique solution for coastal regions, especially in developing economies, which may have demand for many products but do not possess existing or sufficient production and distribution infrastructures.

Table 11. Estimated FPSO OCC for synthetic Jet A fuel production

Jet Fuel Production Ship Capital Cost	2019 USD
Cost of calciner	$2,100,000
Cost of electrolyzer, including all piping and subsystems	$210,000,000
Cost of F-T reactor components	$220,000,000
Subtotal, main components	**$510,000,000**
Instrumentation and Control	$5,700,000
Electrical Systems	$18,000,000
Building-integration structures adjusted for ship-based scenario	$10,000,000
Subtotal, other subsystems	**$33,000,000**
FPSO nuclear heat source block	$120,000,000
Balance of hull and power block	$740,000,000
Subtotal, hull and power block cost	$860,000,000
Total OCC	**$1,400,000,000**

Table 12. Levelized cost of synthetic Jet A fuel

Levelized Jet Fuel Cost		2019 USD
Annual jet fuel production (tonne/year)*	510,000	
Annual jet fuel production (bbl/year)*	4,000,000	
Total FPSO capital cost		$1,400,000,000
Capital period (years)	30	
Interest rate	**7%**	
Annualized capital expense		$110,000,000
Direct crewmember count on staff	500	
Annual expense per crewmember	$100,000	
Annual staffing expense		$50,000,000
$CaCO_3$ (limestone) consumption, tonne/year	3,700,000	
Cost of limestone USD/tonne	$7	
Annual limestone expense		$25,000,000
Annualized reactor consumables expense		$94,000,000
Annual fuel and consumables expense		$120,000,000
Annual maintenance expense (2.5% of OCC)		$35,000,000
Annual administration, insurance, operations, and decommissioning expense		$9,500,000
Total annual expense		**$330,000,000**
Levelized cost of jet fuel ($/tonne)	**$640**	
Levelized cost of jet fuel ($/bbl)	**$82**	

*Accounting for production capacity factor.

The Scenario 3 FPSO platform is smaller than those employed in Scenarios 1 and 2 but is outfitted with a more diverse set of large-scale processing equipment (Figure 17). Like the ammonia production FPSO in Scenario 1, the poly-generation FPSO requires an HTSE kit to produce hydrogen and ammonia synthesis processing equipment to produce ammonia. The steam turbine generator is configured with higher condenser pressure to provide the thermal energy for a large-scale MED desalination unit.

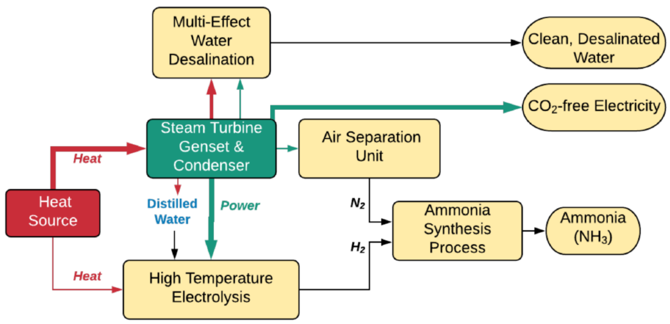

Figure 17. Combined electricity, ammonia, and desalinated water production process for FPSO-based polygeneration scenario

The availability of low temperature heat allows for and favors optimizing the MED process for low capital and operating costs rather than high production rates and results in relatively low-cost fresh water and much lower salinity in the brine discharged from the process. Cooling water from the systems can be mixed with the discharge from the desalination process for additional dilution prior to discharge to the local marine environment.

Near shore mooring of the Scenario 3 FPSO platform allows for delivery of potable water and ammonia via dedicated pipelines and electricity via underwater transmission cable.

The FPSO facility envisioned for polygeneration in Scenario 3 requires half the power generation capacity, a much smaller hydrogen generating capacity, and a smaller ammonia plant compared to the FPSO concepts described in Scenarios 1 and 2. The plant heat source is sized for a capacity of 1,300 MWt. In this scenario a thermal desalination unit with an 80 °C steam inlet temperature is configured in place of a power block's typical condenser, transforming the condenser function into a simple low-cost multi-effect water distillation system. Table 13 summarizes the corresponding production characteristics and physical parameters assumed for the polygeneration scenario.

4.3.2 Market Opportunity

The poly-generation FPSO in Scenario 3 potentially benefits from access and exposure to three distinct markets. The roles and opportunities for zero-carbon electricity are universal and well-understood. The market opportunity for carbon-free ammonia as a current global commodity and future liquid fuel substitute is described above in Scenario 1. Moreover, ammonia also offers a storable and conveyable hydrogen energy carrier.

Table 13. Polygeneration energy source, production potential, and physical specifications

Primary Energy Source	
Thermal capacity (MWt)	1,300
Electricity generation capacity (MWe)	580
Capacity factor of production (applies to all product lines)	90%
Polygeneration Production Potential	
Electricity	
Thermal resource-fraction sold as electricity (%)	20%
Electricity production, maximum electric power (MWe)	120
Electricity available to sell (MWhe/year)*	920,000
Water	
Thermal resource-fraction (above recovered waste heat) sold as water (%)	1%
Water production rate (m^3/day)	330,000
Water available to sell (m^3/year)*	110,000,000
Ammonia	
Thermal resource-fraction sold as ammonia (%)	79%
Ammonia production, peak production capacity (tonne/hour)	44
Ammonia available to sell (tonne/year)*	230,000
Physical Specifications	
Platform dimensions	L: 284.5m; W: 53m; H: 31.5m
Lifetime (years)	30
Displacement (tonnes)	76,000

*Accounting for production capacity factor.

Access to reliable, safe, affordable potable water is increasing in importance and relevance. The potential future demand for potable water in the developed and developing world is underscored by a number of observations: [14, 15, 16]

- Increasing population concentrated on the coasts and changing climate patterns are straining fresh water resources in many regions of the world
- 40% of the world's population lives withing 100 km of a coast
- Fresh water comprises only 2.5% of the water on earth and only 1% of that fresh water is readily accessible for use
- Large-scale desalination technology is mature and in use around the world

14 Factsheet: People and Oceans. The Ocean Conference. United Nations. New York: June 5-9, 2017. https://www.un.org/sustainabledevelopment/wp-content/uploads/2017/05/Ocean-fact-sheet-package.pdf

15 Where is Earth's Water? United States Geologic Survey. 2021. https://www.usgs.gov/special-topic/water-science-school/science/where-earths-water?qt-science_center_objects=0#qt-science_center_objects

16 N. Voutchkov. Desalination – Past, Present, and Future. International Water Association. August 17, 2016. https://iwa-network.org/desalination-past-present-future/

Figure 18. Scenario 3 — Power, ammonia, and desalination polygeneration via an FPSO moored close to shore for flexible product delivery to land. Not shown are pipelines and underwater transmission cables sending products to shore.

The desalination market in the Middle East and Africa reached $7.9 billion in 2017, and the global market is expected to grow at a CAGR of 7.8% through 2025 [45]. In light of increasing environmental and population pressures factors driving clean water scarcity, it is expected that this level of growth will continue beyond 2025.

4.3.3 Producer Perspective

The markets for the three products being produced—hydrogen, power, water—are typically not correlated. Therefore, producers can benefit from three separate revenue streams that also offer some degree of built-in hedging against market volatility. The FPSO is designed to produce products that most coastal cities, especially those in the developing world, will need. It is possible to design the FPSO such that the power output can be set to variably serve power production, fuels production, and desalination. As onshore electricity demand changes, as indicated by pricing or explicit direction from the customer, FPSO electricity generation can be re-dispatched for water or ammonia production to best meet changing needs. It is worth noting, however, that such operational and product flexibility comes at the cost of reduced capacity for equipment; the economic preference would be to operate all capital-intensive power and hydrogen equipment as close to full capacity as possible.

The producer may also have the option to export surplus product, depending on contractual arrangements. Furthermore, the FPSO can be relocated to other markets once a contract expires.

4.3.4 Customer Perspective

Customers can benefit from the option of short-term commitments with a FPSO-based generation source. This opportunity, not offered with fixed land-based facilities and deployment models, can reduce important barriers to entry that typically accompany large capital construction projects for essential power, water, and energy infrastructures in the developing world.

With FPSO production able to swing between ammonia production and electricity generation, power output can be flexibly dispatched to balance grid-based variable renewable sources. The FPSO poly-generation option supports global efforts to meet decarbonization targets while also enabling sustainable economic growth. The FPSO poly-generation model also offers an efficient and cost-effective alternative to construction of separate fuel refineries, electricity generation assets, and desalination capacity.

4.3.5 Indicative Economics

Table 14 outlines the major cost components of the multi-product FPSO. Where necessary, OCC estimates were scaled based on the smaller physical dimensions of the FPSO. Table 15 highlights the levelized costs for power ($/MWhe), Ammonia ($/tonne), and clean, desalinated water ($/m^3). Appendix A provides key references used for OCC and levelized cost calculations.

The FPSO onboard power plant is capable of generating 582 MWe of net electricity. The chosen product-mix affects process equipment capital expense utilization and therefore the cost of each product produced. For estimation purposes, Scenario 3 assumes the plant sells 500 MWe of electricity for 12 hours and then reduces offsite sale of electricity to 200 MWe while diverting the remaining 300 MWe to the HTSE unit for hydrogen production. The ammonia plant is assumed to operate around the clock, using hydrogen from either storage or directly from the HTSE units. Produced ammonia is temporarily stored on board before being transferred to shore via bunker ship.

Table 14. Estimated OCC for multi-product FPSO

Multi-Product Production Ship Cost	2019 USD
Desalination Equipment (MED)	$540,000,000
Electrolyzer	$140,000,000
N_2 generation (cryogenic air separation unit)	$17,000,000
Ammonia Synthesis (Haber-Bosch)	$110,000,000
Piping and transmission	$50,000,000
Subtotal, component cost	**$860,000,000**
Instrumentation and Control	$3,200,000
Electrical Systems	$10,000,000
Building-integration structures adjusted for ship-based scenario	$5,700,000
Subtotal, other subsystems cost	**$19,000,000**
FPSO nuclear heat source block	$80,000,000
Balance of hull and power block	$500,000,000
Hull and power block cost	**$580,000,000**
Total OCC	**$1,500,000,000**

Table 15. Levelized costs for power, ammonia, and water

Levelized Product Cost		2019 USD
Electricity (MWhe/year)	920,000	
Water (m^3/year)	110,000,000	
Ammonia (tonne/year)	230,000	
Overnight capital cost (entire FPSO)		$1,500,000,000
Capital period (years)	30	
Interest rate	7%	
Annualized capital expense		$120,000,000
Direct crewmember count on staff	200	
Annual expense per crewmember	$100,000	
Annual staffing expense		$20,000,000
Annual fuel and consumables expense		$62,000,000
Annual maintenance expense (2.5% of OCC)		$36,000,000
Annual administration, insurance, operations, decommissioning expense		$9,500,000
Total annual expense		**$250,000,000**
Levelized electricity cost (USD/MWhe)	**$43**	
Levelized water cost (USD/m^3)	**$1.30**	
Levelized ammonia cost (USD/tonne)	**$290**	

*Accounting for production capacity factor.

5 Onshore Gigafactory-Based Carbon-Free Hydrogen Production Scenario

5.1 Scenario 4: Onshore Production of Carbon-Free Hydrogen for Blending into Existing Gas Networks

Scenario 4 describes a large hydrogen gigafactory, which is conceived as a single facility where entire production assets are manufactured, installed, commissioned, and operated on site. The gigafactory described in this scenario produces carbon-free hydrogen for feeding directly into an existing gas infrastructure. While this is a land-based scenario, the delivery of major equipment and components and the refueling of reactors favor coastal locations with ready access to marine transport. Access to navigable waterways becomes even more important to leverage the economies of manufacturing scale and serial production for supplying nuclear reactor and plant modules for off-site customers once the on-site demand for hydrogen generation capacity is satisfied.

5.1.1 Overview

Blending of relatively low concentrations (15–20%) of hydrogen into natural gas can be compatible with existing pipeline infrastructures, end-use appliances, and public safety [73]. Efforts are underway to safely increase H_2 concentrations and better understand the changes needed for pipelines and end uses to enable higher blends and ultimately approach 100% pure hydrogen [74, 75]. These efforts include feasibility studies and demonstration projects to test hydrogen concentrations up to 100% in the existing gas network and use of high H_2 gas on end-use products—including combustion turbines—and developing related codes and standards [76].

The hydrogen gigafactory scenario envisioned here represents an even more aspirational model than is proposed for the FPSO-based described scenarios above, including the incorporation of thermochemical processes rather than electrolysis to take maximum advantage of high temperature process heat from advanced nuclear designs and increased efficiency of direct thermal energy to hydrogen production. Figure 19 depicts the hydrogen generation process. As mentioned earlier, this thermochemical conversion technology, while promising, remains the subject of development and demonstration activities and is therefore not currently commercially available at scale. However, as the deployment target for this study is the 2050 timeframe, the assumption is made that commercialization is successful and at least one thermochemical process is available at scale by 2050 in the range of inflation adjusted capital cost estimates derived from the 2003 General Atomics study [77].

Unlike Scenarios 1–3, the nuclear heat sources envisioned for Scenario 4 are smaller reactor units rated at 600 MWt (250 MWe) and are each paired with a complementary modular heat exchanger unit for conveying heat via an intermediate molten salt circuit to the decoupled hydrogen plant. Rail and port access are assumed to be adjacent to the manufacturing facility, allowing future off-site distribution of excess systems and components manufactured that can continue to be manufactured once the planned on-site hydrogen generation capacity is met.

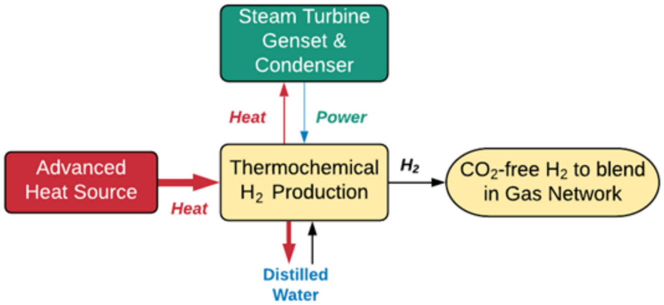

*Figure 19. **Process for scalable hydrogen production via thermochemical processes.** More mature production processes could be substituted with appropriate changes to component, system, and plant configurations.*

Estimated Annual Hydrogen Production Potential

The 36 x 250 MWe plant is expected to produce 250 million GJ of hydrogen energy per year. To put this in perspective, the UK consumed just under 3 billion GJ of natural gas in 2018 [78]. Therefore, twelve of these facilities would be required to replace the UK's current natural gas consumption. Notably, much of the UK's natural gas is used in electric power generation, which would likely be replaced with renewable and nuclear electricity. UK government statistics indicate 1.1 billion GJ/y of domestic gas heating demand, which is the segment that is the most difficult to decarbonize [78]. Table 16 summarizes the gigafactory hydrogen production potential and physical specifications envisioned for Scenario 4.

Table 16. Hydrogen production potential and physical specifications

Hydrogen Production Potential	
Thermal capacity (MWt)	22,000
Electric capacity (MWe)	9,000
Annual H_2 production output (MWht)	65,000,000
Daily H_2 production capacity (BOE/day)	110,000
Annual H_2 production capacity (tonnes)	1,600,000
Annual H_2 production capacity (GJ)	230,000,000
Physical Specifications	
Heat Source Factory	177m x 81m
Precast Factory	91m x 80m
Heat Source Farm	177m x 282m
H_2 Production	221m x 160m
Hookup	124m x 181m
Lifetime (years)	30+

Hydrogen Production at an Integrated Onshore Gigafactory

The gigafactory site (Figure 20) comprises a large thermochemical hydrogen production facility, 36 x 600 MWt (250 MWe) reactors (blue hatches) and power heat exchangers (green hatches), as well as a connection to the existing pipeline network. Figure 21 depicts the development of the hydrogen gigafactory at its midpoint, with the first bank of nuclear heat

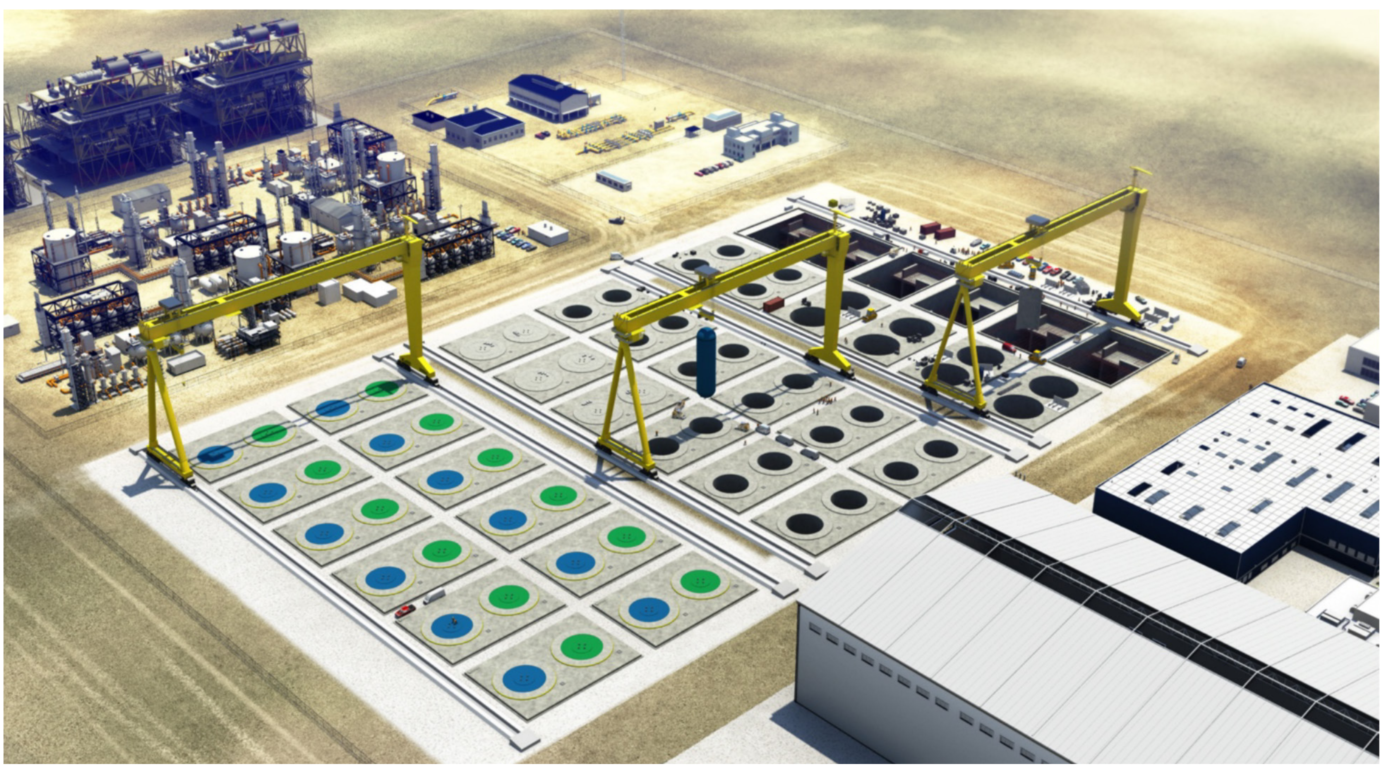

*Figure 20. **Scenario 4 — Hydrogen gigafactory showing a view of facility construction, hydrogen production, and interface for injection into existing natural gas network.** Reactor and balance of plant fabrication and assembly occurs in factory at lower right. As nuclear heat source/reactor units and other systems are completed, they are moved via cranes into position in the reactor farm (center) for below-grade installation of heat sources and their companion heat exchanger modules (blue and green hatches) and to the hydrogen production yard (upper left). Hydrogen is injected at pressure into the existing natural gas network.*

sources/reactors in operation (foreground), the second bank being installed (center), and a third bank (background) where installation of precast concrete structures and other civil works is underway.

The conceptual factory configuration is intended to provide a highly productive, dedicated manufacturing environment (comparable to the engineered shipyard model) where the nuclear heat sources and auxiliary systems are fabricated and installed on-site. Hydrogen production and injection into the existing network are collocated with the gigafactory facility.

5.1.2 Market Opportunity

Worldwide natural gas consumption in 2018 was 3,850 billion cubic meters. This consumption spanned electricity generation, heating, transport, industrial, commercial, and residential uses [79]. The energy potential in this volume of gas roughly equates to 140 billion MMBtu.[17] Assuming a global average LNG price of $6/MMBtu, a conservative estimate of the global market is approximately $820 billion per year. The sheer size and reach of the natural gas market suggest a potentially large market opportunity for direct substitution or offsetting use of fossil resources for greater value-added uses such as feedstocks justifies research, development, and demonstration investments in reducing hydrogen production costs and modifying end-use devices to accommodate hydrogen or a hydrogen blend.

Blending hydrogen into the existing network offers a potentially cost-effective solution to decarbonizing heating and electricity generation, especially in regions where suitable renewable resources are limited. The degree to which carbon-free hydrogen can be used for electricity generation depends on the technical maturity and commercial availability of flexible and dispatchable combustion turbines and internal combustion that can run on hydrogen (or its derivative products like ammonia). The economic opportunity and incentive for use of nuclear generated hydrogen and derivative products to augment or replace natural gas ultimately depends on the relative value that the energy storage and dispatchable energy such resources provide in the markets served.

Figure 21 shows existing UK nuclear capacity and the estimated generation capacity (GWe) that would be required to produce enough hydrogen to replace the natural gas used for cooking, water and space heating in the United Kingdom, which is equivalent to 35 GWt [78]. Accounting for HTSE efficiency, this requirement corresponds to almost 40 GWe of nuclear capacity.

In the United States, component testing for the natural gas transport and distribution infrastructure is underway to evaluate service with various hydrogen concentrations [80]. Standards are also being developed for hydrogen conveyance and use in existing infrastructure equipment; these will establish acceptable levels of hydrogen that can be used within existing and modified natural gas systems [80]. Similar efforts are underway elsewhere.

17 There are 28.26 cubic meters of natural gas in 1 MMBtu.

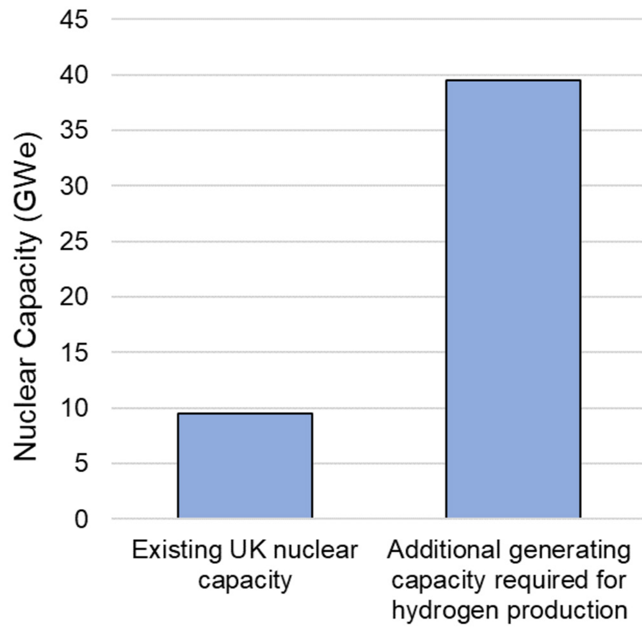

Figure 21. Electricity generation capacity required for hydrogen production sufficient to displace UK natural gas consumption used for heating. Data from 2019 Digest of UK Energy Statistics [78].

Because natural gas injection into pipeline networks generally occurs at a limited number of locations, a hydrogen gigafactory deployment model could take advantage of key interconnection points within a gas network, thereby avoiding the investment needed to connect geographically scattered hydrogen projects to the main gas distribution network.

Alternatively, the zero-carbon, large-scale hydrogen production volume offered by the gigafactory model could also be leveraged for the land-based production of ammonia, synthetic jet fuel, and other products that require hydrogen as a feedstock. Likewise, integrating the nuclear heat sources with an appropriately sized thermal energy storage systems could also enable the flexible co-generation electricity for dispatchable peaking capacity to meet grid demand during periods of increasing loads or decreasing generation.

5.1.3 Producer Perspective

The gigafactory concept transforms the construction and operation of non-emitting energy and power generation in terms of economy and scale. The entire facility is carefully designed for manufacturing and assembly to yield a high throughput, automated, factory-based production system for the entire fabrication, assembly, and installation process. Simplified lean designs with fewer components minimize labor costs and enable the application of fast, high-quality modular construction techniques. Work is organized to maximize learning and continuous improvement, leading to increases in productivity and reductions in rework.

Such serialized, standardized processes can also enhance and simplify regulatory oversight. Because the regulator sees the same factory, same team, same processes, and the same products, opportunities increase for streamlining inspections and approvals, resulting in corresponding opportunities to reduce regulatory costs over time. Fabrication, assembly, and installation of nuclear heat sources, balance of plant, and hydrogen production systems in parallel fashion also potentially reduces the impact of individual delays and cumulative effects on the commercial operation of the nuclear-hydrogen production plant at some capacity. Unlike stick-built construction, delays in one area would not necessarily cross over to other project elements.

A vertically integrated fabrication-assembly-construction-operation site potentially enables significant economies of scale for building uniform units. Site-specific licensing, preparation, and engineering costs, along with other non-recurring development and qualification costs, can spread over large numbers of units relative to plants featuring units in the single digits. This degree of vertical integration also eliminates many transportation costs delays associated with major component delivery, inspection, and layup.

5.1.4 Customer Perspective

Gas grid operators and hydrogen consumers would be able to take hydrogen delivery in real time from the gigafactory. The hydrogen can be injected into the network for direct use or for appropriate storage, ensuring adequate reserves for reliable delivery even during peak and extraordinary demand.

5.1.5 Indicative Economics

The onshore hydrogen factory represents a substantial infrastructure mega-project. The centralized nature of the gigafactory design enables several different cost reduction pathways, as discussed above. Table 17 describes the high-level OCC estimate for the project. Although building the precast concrete and reactor manufacturing factories is a major investment, it represents a relatively minor proportion of the plant's cost when spread over the number of units installed. Table 18 describes assumptions used to estimate the levelized cost of hydrogen for this scenario.

The gigafactory scenario envisions eventual connection of 36 reactor modules to the thermochemical hydrogen production process via a molten salt heat transport piping network. The thermochemical hydrogen plant is 9-times the unit size of the plant in the reference 2003 design study [77]. The study incorporated many conservative cost estimates for specialty components. Moreover, a subset of components, roughly 10 out of 60, account for two-thirds of the cost. Re-engineering and volume production may yield cost reductions for improved competitiveness to enable scaling.

Table 17. Estimated OCC for onshore hydrogen gigafactory

Hydrogen Gigafactory Cost	2019 USD
Thermochemical hydrogen plant	$3,300,000,000
Precast factory	$90,000,000
Reactor manufacturing factory	$250,000,000
Heat pipes	$100,000,000
Cranes	$90,000,000
Water desalination	$47,000,000
Subtotal, main elements	**$3,900,000,000**
Water systems	$220,000,000
Piping	$540,000,000
Instrumentation and Control	$320,000,000
Electrical systems	$540,000,000
Auxiliary systems	$430,000,000
Subtotal, other systems	**$2,100,000,000**
Subtotal, buildings	**$1,100,000,000**
Subtotal, heat source and heat exchangers	**$6,500,000,000**
Total OCC	**$14,000,000,000**

6 Further Cost Reduction Opportunities

The current early-stage posture of the synthetic and zero-carbon fuels industry means that cost reductions remain untapped, given that this industry has not yet invested in volume production and designs for manufacturability. The nuclear industry in particular has not benefitted from cost, schedule, and risk reductions through leveraging of opportunities provided by new technologies, design paradigms, and manufacturing methods.

Based on series-build experience in large commercial shipyards, a potential opportunity exists for volume manufacturing and lean-continuous improvement to substantially reduce costs for FPSO hull, structures, and other major components. This effect can be further magnified if enhanced manufacturability of design and increased use of automation are incorporated.

Leveraging of innovative enabling technologies, novel practices, optimization, and other opportunities reduce deployment costs, timeframes, and risks. Notable examples include:

- Printed circuit heat exchangers for increased use of advanced manufacturing methods and reductions of fabrication costs.
- Elimination of synchronous operation of turbomachinery to satisfy electricity grid requirements to provide greater freedom for optimizing plant design.
- Incorporation of new component and system technology, such as compact heat exchangers and high-speed turbogenerators, to reduce the physical footprint of the heat source and power generation blocks.

Table 18. Levelized costs for hydrogen gigafactory

Levelized Product Cost		2019 USD
Hydrogen (tonne/year)	2,000,000	
Overnight capital cost		$12,000,000,000
Capital period (years)	20	
Interest rate	7%	
Annualized capital expense (USD/year)		$1,200,000,000
Direct staff	1,200	
Annual expense per staff member (USD/year)	$120,000	
Total annual staffing expense (USD/year)		$140,000,000
Fuel and consumables (USD/MWht)	$2	
Total fuel and consumables cost (USD/year)		$340,000,000
Maintenance, 2.5% of capital expense (USD/year)		$310,000,000
Total annual expense (USD/year)		**$2,000,000,000**
Levelized cost of hydrogen (USD/kg)	**$0.91**	
Levelized cost of hydrogen (USD/MWht-HHV)	**$23**	
Levelized cost of hydrogen (USD/MMBtu-HHV)	**$6.70**	

From an owner-operator perspective, moving plant operations to centralized and/or offshore facilities could offer opportunities to drive down O&M costs [81].

Emerging technologies also offer potential future prospects for simplifying plant configurations with commensurate cost reductions. For example, the availability of a co-electrolysis process that can produce syngas directly from water and CO_2 in one step could offer opportunities for reduction of equipment and overall process simplification for reduced capital costs [39].

7 Summary and Conclusions

Without further innovation for and penetration by non-emitting energy technology options, fossil fuels could continue to supply a substantial fraction of global primary energy into 2050, even with high deployment rates of existing renewable technologies. This trajectory threatens national and international efforts to reduce carbon emissions for climate change mitigation. Deep decarbonization efforts are particularly challenged by hard-to-decarbonize sectors such as heavy-duty transportation.

This work explores and evaluates a future vision for advanced nuclear energy in which sufficient market demand exists to drive deployment of advanced reactors at scales that enables and benefits from serial production in fully engineered environments for fabrication, manufacturing, and assembly. Efforts to identify promising nuclear expansion scenarios clearly intersect with growing interest in decarbonizing economies and transitioning energy production and consumption toward net zero and carbon-free solutions.

Transformation of fuels markets requires cost-effective production at scales commensurate with demand. The likelihood of reaching such scales by 2050 could be increased if disruption to storage, distribution, performance, and end-users were minimized. Drop-in zero-carbon substitutes for fuel and other products that reduce behavioral changes and capital investments in infrastructure and equipment on the consumer end such as those explored herein offer credible options consistent with economy-wide energy transition away from fossil fuels over the coming decades.

This work highlights how innovative technology configurations, combined with highly efficient delivery and deployment models for hydrogen and synthetic fuel production facilities can transform global prospects for an achievable clean energy transition within a reasonable timeframe. Pull from these markets could be strong enough to drive transformational changes in how liquid fuels are produced without disrupting cost, storage, distribution, or use. Commodities produced for these non-electricity markets (for example., hydrogen and zero-carbon liquid fuels) can rapidly accelerate decarbonization of the global energy system while minimizing cost and disruption to producers or consumers.

Preliminary techno-economic assessment results for the four proposed deployment scenarios (summarized in Table 19) suggest competitive pricing for zero-carbon fuel products and other commodities from advanced nuclear energy sources and new deployment models are possible within the 2050 time horizon.

Table 19. Comparison of benchmark prices (without carbon abatement) from Table 2 with estimated levelized zero-carbon production costs associated with Scenarios 1–4

Product	Benchmark Price (without carbon abatement)	Levelized Zero-Carbon Product Cost	Units
Jet A	120	80	million USD
(Kerosene-Type Jet Fuel)	94	82	USD/bbl
Ammonia (NH_3)	200	230–290	USD/tonne
Electricity	68.3 – 185[a] 102 – 334[b]	43	USD/MWh
Desalinated Water	0.64 – 2.86	1.3	USD/m^3

a OECD industrial electricity price range for 2019

b OECD residential electricity price range for 2019

c Cost of production; does not include transmission, distribution, and other system costs

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A Principal Sources for Techno-Economic Assessments

Scenario 1: Production of Ammonia for Marine Shipping Fuel
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Scenario 3: Production of Carbon-Neutral Power, Ammonia, and Desalinated Water
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Scenario 4: Onshore Production of Zero-Carbon Hydrogen for Blending into Existing Gas Networks
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Units and Conversion Factors

Common Units and Quantities

The oil, gas, and chemical industries use units of measurement that may be unique or differ from those used in the electric power and nuclear energy industries. Four principal quantities and corresponding units are used for characterizing hydrocarbons and other liquid fuels and products in this report:

Quantity	Symbol	Name
Energy	J	Joules
Energy generation represented as power integrated over time	Wh	Watt-hours
Mass	t	tonnes or metric tons
Volume	m^3	cubic meters

Oil and refined products, such as jet fuel, are also commonly measured in US barrels (bbl) and US gallons.

Prefixes

Standard prefixes k (kilo=1000), M (Mega, 1,000,000) and G (Giga, 1,000,000,000) are used throughout except where the dominant industry convention suggests otherwise. Notably, the prefix MM may be used to denote millions per convention for natural gas quantities.

The prefixes Tera (10^{12}) or Peta (10^{15}) are not used. Instead, quantities are expressed as thousands and millions of kilo-, Mega-, and Giga-units.

Currency

Currency is denominated in U.S. dollars throughout unless otherwise indicated. The symbol "$" is used in text, captions, and labels; the initialism USD is used in tables.

Significant Figures

Two significant figures are used for estimated costs and other quantities to reflect the uncertainty inherent in the point estimates.

Conversion Factors

Relevant conversions for this report include:

Unit	Equivalent
1 MWh	3.600 GJ
1 MJ/kg	1 GJ/tonne
1 MMBtu	1.055 GJ
1 m^3	35.31 ft^3
1 US gallon	0.003785 m^3
1 US barrel (bbl)	42 US gallons 0.1590 m^3
1 barrel (oil) equivalent (BOE)	6.1 GJ 1.70 MWht

Calorific Values

Calorific values (CVs) can be based on post combustion condensation of the resulting water, denoted higher heating value (HHV), or not, denoted as lower heating value (LHV). Process and efficiencies are often quoted in LHV terms, which can make electrolyzers appear less efficient and gas turbines and fuel cells more so. Approximate values for common fuels and energy carriers are:

Product	HHV (MJ/kg)	LHV (MJ/kg)
Methane	55.5	50.0
Kerosene/Jet A	46.4	43.2
Hydrogen	142	121
Ammonia	22.5	18.6
Fuel oil	43.3	40.9

Acronyms and Initialisms

ASU	Air Separation Unit
bbl	Barrel (oil)
BOE	Barrel of Oil Equivalent
Btu	British thermal unit
CAGR	Compounded Annual Growth Rate
OCC	Overnight Capital Cost
CCS	Carbon Capture and Sequestration
CGN	China General Nuclear
DfMA	Design for Manufacturing and Assembly
DSME	Daewoo Shipbuilding and Marine Engineering
EPRI	Electric Power Research Institute
FOAK	First-of-a-kind
FPSO	Floating Production Storage and Offloading
GHG	Greenhouse Gas
GTI	Gas Technology Institute
GWe	Gigawatt-electric
GWt	Gigawatt-thermal
HHV	Higher Heating Value
HTE	High-Temperature Electrolysis
HTCE	High-Temperature Co-electrolysis
HTGR	High-Temperature Gas-cooled Reactor
HTSE	High-Temperature Steam Electrolysis
IAEA	International Atomic Energy Agency
IATA	International Air Transport Association
IMO	International Maritime Organization
IOGP	International Association of Oil and Gas Producers
LHV	Lower Heating Value
LNG	Liquified Natural Gas
LSFO	Low Sulphur Fuel Oil
LWR	Light Water Reactor
MED	Multi-Effect Distillation
MM	Million (customary prefix)
MSR	Molten Salt Reactor
NOAK	Nth-of-a-kind
NSSS	Nuclear Steam Supply System
O&M	Operations and Maintenance
RD&D	Research, Development, and Demonstration
SCR	Selective Catalytic Reduction
SFR	Sodium-cooled Fast Reactor
t	Tonne or Metric Ton
USD	United States Dollar
WACC	Weighted Average Cost of Capital

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