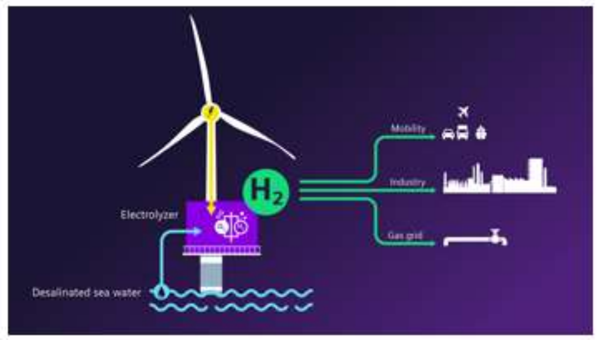
Analysis of Levelized Costs of Energy for Repurposing Offshore Infrastructure for Clean Energy (ROICE) Projects in the Gulf of Mexico

ROICE Techno Economics
Phase 1 Report

Courtesy: Endeavor Management



Courtesy: Siemens Gamesa

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I. Executive Summary

As the 1500 plus oil & gas structures in the US Gulf of Mexico (GOM) reach the end of their oil & gas phase, these structures as well as the thousands of miles of pipelines have the potential to be converted into ROICE (Repurposing Offshore Infrastructure for Clean Energy) projects. Repurposing is the re-use of some or all the existing infrastructure for a new project. A comprehensive model has been developed for estimating levelized costs (LC) for such projects. The ROICE LC Model can estimate LC's for wind power and hydrogen generation for both new build projects as well as projects that repurpose some of the existing oil & gas infrastructure.

Using this model, heat maps have been generated that show LC distributions for different project scenarios across the GOM. These scenarios include new build and repurposed versions of wind and hydrogen projects at two different project sizes (demonstration scale and commercial scale). These heat maps have been analyzed to identify favorable locations for ROICE projects, how they compare with onshore and other alternatives, and to understand the impact of various key variables and cost elements on LC.

The LC heat maps were used to estimate screening level LC values for each of the ~1500 assets in the GOM to identify favorable locations for different versions of ROICE projects. A shortlist of 50 assets has been developed for more detailed study in Phase 2 of this project.

Key conclusions from Phase 1 of this study are as follows:

- Levelized costs for ROICE projects are a complex function of various variables – wind speed, water depth, distance to shore, project size, new build vs, repurposed being the primary influencers.
- LC's for repurposed wind projects in the GOM range from \$82 to \$231 per MWh. Equivalent new build projects have LC's ranging from \$82 to \$437.
- LC's for repurposed hydrogen projects in the GOM range from \$4.76 to \$8.44 per kg of hydrogen. Equivalent new build projects have LC's ranging from \$4.77 to \$19.64.
- While noting that the above LC's do not include any federal or state incentives, these are higher than equivalent low-carbon renewables-based onshore projects, and even more challenged versus high-carbon alternatives.
- However, projects at the lower end of the range of LC's across the GOM have the potential to be competitive with onshore projects through efficient design, cost reductions and use of all available federal and state incentives.
- Of the different components of the oil & gas structure to be repurposed, it is probably most cost-effective to reuse the jacket (main support structure) and the deck (flooring above the structure) for ROICE projects. The remaining equipment will need to be decommissioned as per normal practice - removal of oil & gas topsides, abandonment of all wells and any pipelines that will not be used to transport hydrogen.
- Such repurposing has the dual impact of reducing capex and shortening the schedule of implementation of ROICE projects. Repurposing will have a positive impact on LC for most projects. This improvement is more pronounced for deeper water projects and for smaller scale projects where the savings from reused infrastructure form a significant portion of the total project capex.
- A hydrogen generation project can reduce Capital Expenditure (CAPEX) by 10 to 15% in many cases. Other cases result in no more than a ~10% increase in CAPEX. The incremental economics on such additional CAPEX for hydrogen generation is likely to be promising, especially considering the healthier federal incentives for hydrogen production vs wind power generation.

- Shallow water / near-shore locations appear to have the lowest LC for all cases - new build or repurposed, power or hydrogen projects. This is due to several reasons – higher wind speeds, lower structural costs, lower cable costs, etc. Repurposing improves the LC by 5 to 10% for these locations.
- Further away from shore, in deeper waters, hydrogen projects and repurposing prove to be more attractive. Hydrogen projects remain relatively attractive as water depth increases, and repurposing can reduce the LC by up to 25% for larger scale projects and up to 60% for smaller scale projects.
- In regions where repurposing has a significant impact, the overall LC is high even with repurposing, indicating challenging project economics. Stronger government incentives and major cost reductions will be needed to make these competitive.

These conclusions will be further tested and refined in Phase 2 of this project where the ROICE project designs and assumptions will be improved for 50 assets in the US GOM.

II. Introduction

A. Offshore Oil & Gas Infrastructure in the US GOM

Over the last 75 years, roughly 7000 platforms have been installed in the Gulf of Mexico (GOM). Additionally, the GOM infrastructure includes 14,000 wells and 10,000 miles of pipelines. These assets, once they reach the end of their fossil energy purpose, are “decommissioned,” usually meaning plugged and abandoned (wells), removed or preserved in place (pipelines), taken apart and brought back to shore, or sunk to the ocean floor (platforms and structures). As of 2023, about 5500 platforms have been decommissioned. According to the US Bureau of Safety and Environmental Enforcement (BSEE 2023), as of June 2023, there are about 1533 structures remaining on the GOM Outer Continental Shelf, with 356 of them having submitted applications for decommissioning. (Figure 1) 7 of these have submitted applications for re-use. 74 are proposing to use the “Rigs to Reef” provision, and the rest (275) are expected to be brought back to shore.

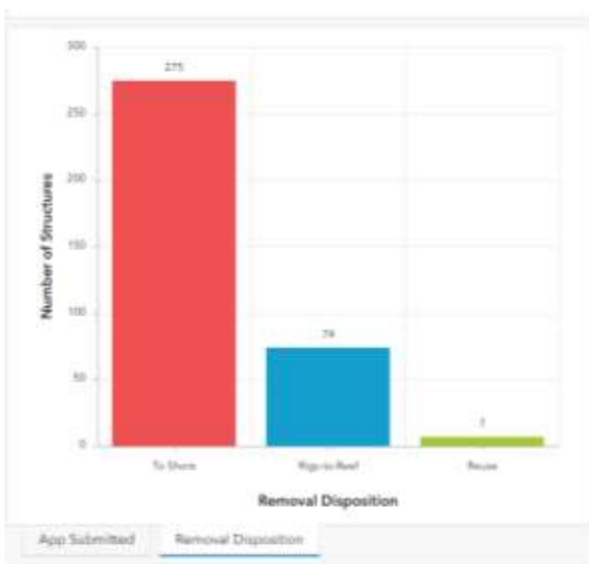


Figure 1: Offshore Decommissioning Requests Count for the GOM

Figure 2 shows the distribution of the infrastructure – platforms, structures and pipelines in the US GOM.

A recent article in the Journal of Petroleum Technology (Presley, 2023) quotes that over the past decade, the offshore energy industry has averaged 200 platform removals per year. It also states that decommissioning in the GOM is expected to grow at a compound annual growth rate of about 6.89% from 2020 through 2030.

The central thesis of this project is that a sizeable fraction of this infrastructure can be reused for clean energy projects given the right structural and geospatial conditions, technology improvements and federal and state incentives. For example, platforms and other structures can be used to support equipment for wind energy and hydrogen generation, pipelines can be used to bring hydrogen to shore. Such repurposing projects are referred to here as ROICE projects. These projects can extend the life of installed infrastructure, reduce carbon footprint vs new build, and generate clean energy jobs and revenue. Further, as a few studies have shown that these offshore structures become ecologically important artificial reefs and positively alter the ecosystem around these platforms (van Elden et al., 2019). Through ROICE projects, this positive impact can continue to be available for an additional decade or two.

The US Bureau of Ocean Energy Management (BOEM) conducted a study of potential offshore renewable energy sources in the GOM to quantify their feasibility relating to resource adequacy, technology maturity, and the potential for competitive cost (Musial, Tegen, et al., 2020). Of all the technologies, offshore wind had the largest quantity of technical resource potential with 508 gigawatts (GW). Shallow water oil and gas production platforms could potentially be used to site integrated offshore wind-electrolyzer systems.

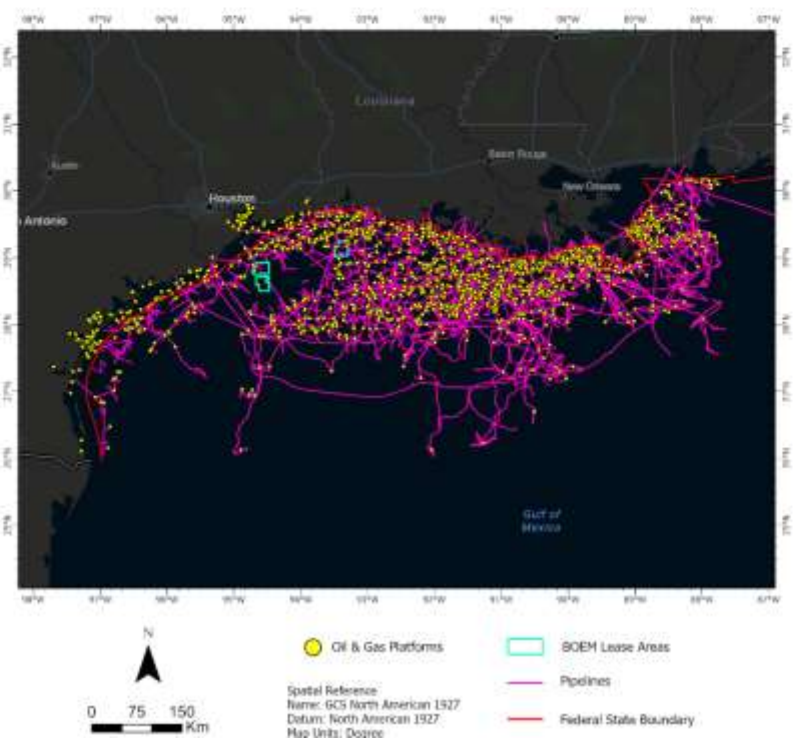


Figure 2: Oil and Gas Platforms, BOEM Lease Areas, Pipelines in the Gulf of Mexico

The wind speed distribution across the Gulf of Mexico ranges from 7 to 9 meters/second (Musial et al. 2020) While these speeds are lower than in other geographical areas such as the US Atlantic Coast (7.4 to 9.3 m/s) (Peevey & Lenoir, 2022) and the UK North Sea (8 to 14 m/s) (Hahmann et al., 2022)

A recent BOEM and National Renewable Energy Laboratory (NREL) study (Musial et al. 2020) showed that when the full range of economic factors are considered, the Texas Gulf Coast appears to have some advantages for economical wind development. This is shown in Figure 3 as a net value which refers to estimated revenue minus the levelized cost. Proximity to population and industrial demand centers make wind a higher value proposition along the Texas Gulf Coast.

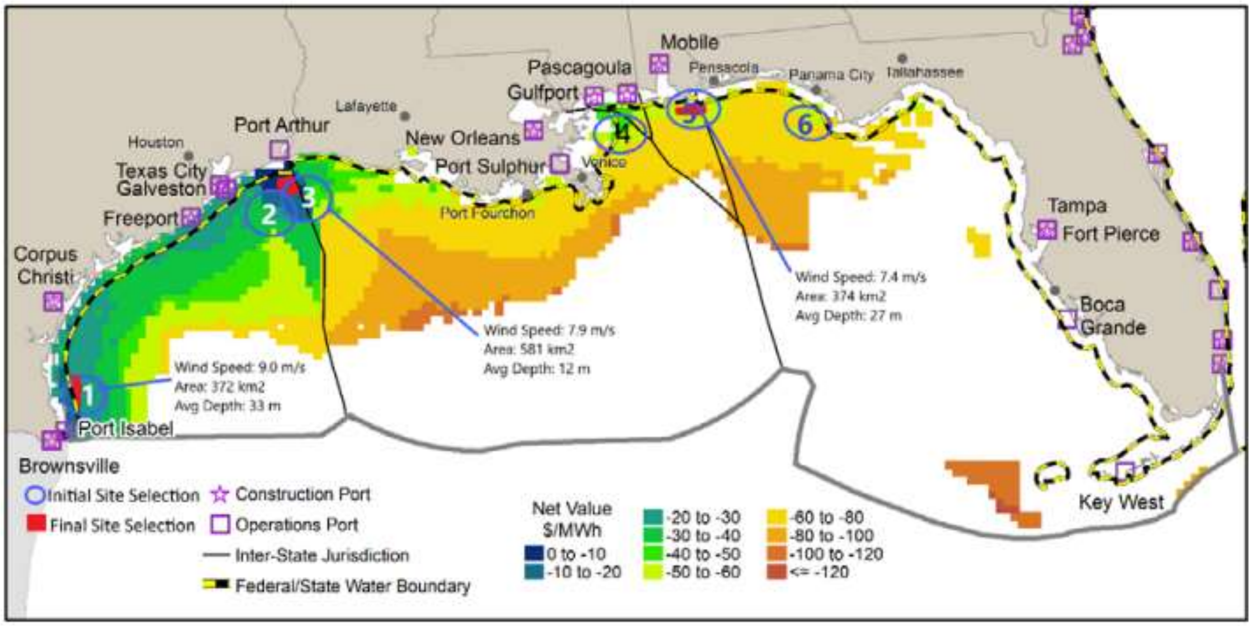


Figure 3: Estimated Net Value of Offshore Wind for the Gulf of Mexico (2030 COD)

Offshore power generation from wind energy is a well-established concept and a global industry. The United States has 187 offshore wind farm projects of which 2 are currently operating, 2 are in the build phase, and 24 are either consented or have applied for consent (4C Offshore 2023). The US Bureau of Ocean Energy Management (BOEM) has issued multiple wind leases and announced future lease areas (wind planning) on the Atlantic and Pacific coasts of the US (Figure 4 and Figure 5).

Figure 4: Pacific Wind Leases and Announced Future

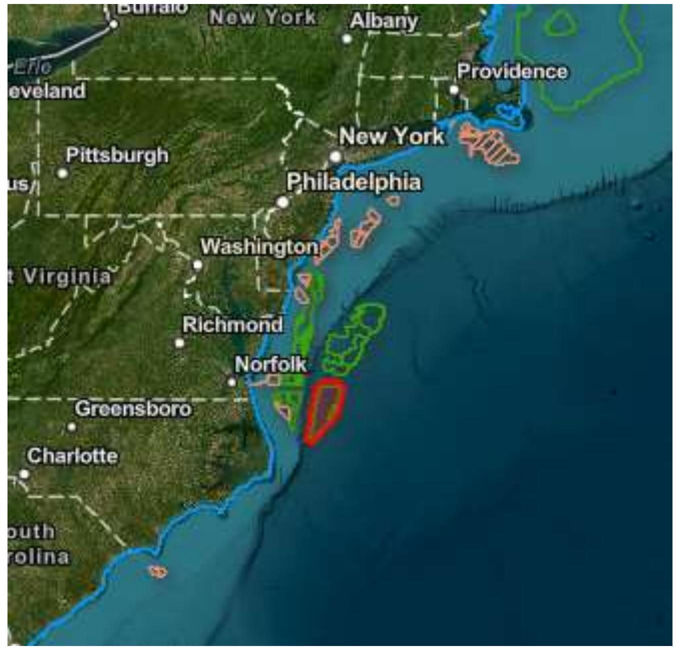


Figure 5: Areas Atlantic Wind Leases and Announced Future Areas

The shallow near-shore waters of the GOM also make it attractive for wind energy development. Recently, BOEM announced two prospective wind lease areas in the Gulf of Mexico, shown in Figure 6 below, superimposed on a bathymetry map for the GOM.

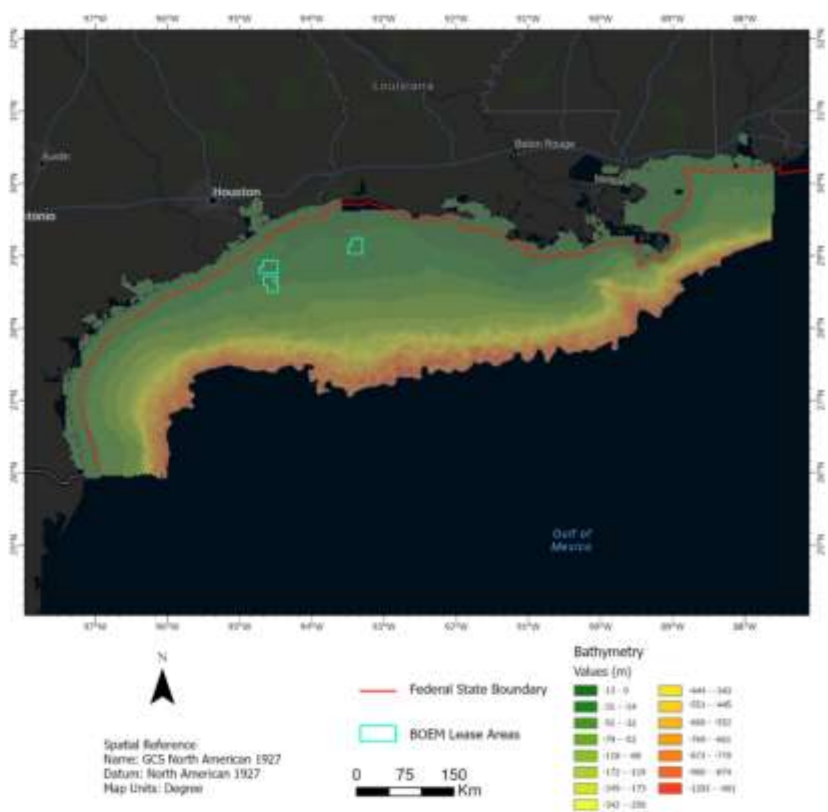


Figure 6: Western Gulf of Mexico Bathymetry

Previously, the Center for Houston's Future and the University of Houston led the assessment of opportunities for expanding clean H2 value chains in Texas and developed a vision and roadmap to enter and expand new markets for hydrogen (Sariyeva et al., 2020). While the primary focus was on opportunities to leverage existing land based H2 manufacturing and logistics systems, offshore renewable power and hydrogen systems were included in the vision as part of a longer-term scaling of hydrogen. Hydrogen's role in the transition to low-carbon energy has been investigated by several studies (Bean et al., n.d.; Krishnamoorti et al., n.d.) Demand from use cases such as long-distance mobility for medium and heavy-duty vehicles, marine and aviation fuels, fuel switching for industrial energy is expected to result in a 6 to 8 times increase in the demand for low carbon hydrogen (- International Energy Agency, n.d.). According to this report, the cost of low-carbon hydrogen can come down significantly with technology innovation and increased deployment.

The potential for hydrogen generation from wind power is also evident in the number of pilot and small - scale projects that are underway elsewhere in the world. Some examples are:

- The PosHYdon project – a consortium of companies including Neptune Energy and NEL are working on generating hydrogen from wind offshore on an operating natural gas platform in the North Sea, and blending the hydrogen with natural gas to bring it to shore (Peters et al., 2020)
- The HOPE project – a consortium of companies including Lhyfe and Plug Power, aims to demonstrate the technical and financial viability of large-scale hydrogen production in the North Sea. Hydrogen will be produced offshore with desalination and electrolysis powered by onshore wind power. (Hart Energy Staff, 2023)
- Lhyfe has other pilot projects for offshore hydrogen from wind power, such as the one off the coast of Le Crosisic in partnership with Centrale Nantes (*Offshore Renewable Hydrogen*, 2021)
- Technip FMC is participating in a few pilot projects such as Deep Purple (in partnership with Repsol, NEL, ABB and others) (TechnipFMC, 2023) and BEHYOND (in partnership with EDP) (edp, 2023) to develop solutions for offshore hydrogen from wind power.
- Onshore wind – hydrogen synergies have been looked at in a project based in Rotterdam (Port of Rotterdam, 2021), and a pilot project in Utah (Mitsubishi Power, 2020) (ca.gov, 2020).

The Texas Gulf Coast region and the Gulf of Mexico has significant potential for such clean hydrogen supply projects, underpinned by the area's potential to be a driver and a hub for an increase in demand for hydrogen. With a population of more than 7 million, it simultaneously represents a strong demand and skill pool. The area's 30 plus refineries, over 100 chemical and other plants represent ~40% of the total chemical and refining capacity of the nation. The industrial infrastructure and demand centers thus serve as ready customers for a sustainable and scaled up offshore wind-hydrogen concept. The proximity to the super-sized electrical network operated by ERCOT with a ~$10 billion/year energy market and over 20 million customers also position the concept for effective scale-up.

Hydrogen produced by an integrated offshore wind-electrolyzer system could be moved to shore by pipe, either newly laid pipe or possibly via existing subsea natural gas infrastructure. It is estimated that the GOM has approximately 13,135 mi (21,139 km) of active natural gas pipelines in federal waters. There are also more than 15,000 mi (24,140 km) of abandoned pipeline that could be potentially leveraged to transport hydrogen to shore (GAO, 2021).

Additional advantages of the Texas Gulf Coast for such a concept include:

- Ready access to seawater as green hydrogen feedstock material, thus avoiding competing with existing demand for already limited freshwater supplies in the region.
- Hydrogen can be stored in large quantities for long durations onshore or offshore in subsurface salt caverns, depleted oil and gas reservoirs, or in deep saline aquifers.
- The Gulf Coast onshore is home to a globally premier hydrogen system, including extensive production, transportation, and storage assets. Hydrogen production in the Gulf Coast amounts to 3.5 million metric tons per year, and the region also has more than 1,000 miles of hydrogen pipelines (Chevron, 2023).
- Global demand for hydrogen is expected to grow 5 to 8-fold by 2050 (Global Hydrogen Review 2021)
- Offshore wind speeds are higher and more consistent than onshore winds, which helps to maximize electrical power per acre and potentially reduces the operational challenges of onshore wind intermittency.

By harnessing these advantages, leveraging the extensive oil and gas infrastructure for repurposing, leveraging learnings from ongoing projects elsewhere in the world, the US GOM can be positioned to be ready with profitable ROICE projects. To realize this potential, many challenges facing such ROICE projects will need to be addressed. A key one is project economics. Along with the well-known challenge of the levelized cost differential between low-carbon electric power (Table 1) and the current fossil-based power generation, and between low-carbon hydrogen and current industrial hydrogen (Table 2), moving the systems offshore adds additional costs.

*Table 1: Levelized Cost of Electricity (LCOE) for Various Generation Pathways ** (Lazard, 2023)

Generation Pathway*	Min	Max
Solar PV - Utility Scale	$24	$96
Solar PV + Storage - Utility Scale	$46	$102
Solar PV – Utility Scale (ITC)	$16	$80
Solar PV – Utility Scale (PTC)	$0	$77
Solar PV + Storage - Utility Scale (ITC)	$31	$88
Wind – Onshore	$24	$75
Wind + Storage – Onshore	$42	$114
Wind – Onshore (PTC)	$0	$66
Wind + Storage – Onshore	$12	$103
Gas Peaking	$115	$221
Nuclear	$141	$221
Coal	$68	$166
Gas Combined Cycle	$39	$101

*Table 2: Levelized Cost of Hydrogen (LCOH) for Various Hydrogen Pathways ** (Bartlett & Krupnick, 2020)*

Hydrogen Pathway	Min	Max
SMR**	$1.05	$1.50
SMR with 89% carbon Capture**	$1.75	$2.20
Electrolysis Solar**	$3.40	$6.80
Electrolysis Wind**	$2.50	$4.50

Other technical challenges include ensuring structural integrity and remaining life of the offshore installations (for repurposing projects), reducing the costs of large-scale electrolysis and wind power through economies of scale, finding other cost reductions such as saline water electrolysis technologies (IRENA, 2020), repurposing hydrocarbon pipelines for hydrogen transportation etc. In addition, the regulatory framework, commercial and liability considerations, and public acceptance aspects need to be addressed.

To address these challenges and develop a comprehensive framework for ROICE projects in the US GOM, UH Energy launched the ROICE program with two key initiatives (Figure 7). The first of these is Project SHOWPLACE (Storing Hydrogen from Offshore Wind Power for Load-balancing and Carbon Elimination), which will establish the techno-economic feasibility of a subset of ROICE projects that bring together three components – repurposing existing offshore infrastructure, harnessing wind energy and generating hydrogen from sea water.

The second initiative is ROICE Workgroups (Figure 7). It is a set of seven workgroups that will develop the ROICE Project Implementation Framework (PIF), covering regulatory, commercial, and technical considerations that need to be put in place to make ROICE projects successful. These workgroups are made up of key stakeholders from industry, academia, and policy groups. They will develop a set of white papers that are expected to be valuable reference materials as commercial ROICE projects move forward. ROICE results will be reported elsewhere, this report focuses solely on results from Phase 1 of SHOWPLACE.

Figure 7: UH Energy ROICE Initiatives

B. UH Energy ROICE Program and Project SHOWPLACE

In September of 2021, Project SHOWPLACE was officially launched with a concept workshop held at the University of Houston (University of Houston, 2023). Over 30 representatives of industry, academia, state, and public organizations attended to help refine the ROICE concept and identify key techno-economic studies that need to be carried out to confirm the feasibility of the concept. This led to the formation of the SHOWPLACE Collaborative (SPC), an industry-government-public-academia advisory board that will work towards an ultimate goal of setting up a demonstration project in the Gulf of Mexico to test various aspects of the ROICE concept of repurposing and renewable energy. Currently 33 companies and institutions have joined the SPC, as shown in Figure 8 below. This coalition of advisors continues to grow steadily, providing valuable input into and oversight of the findings of the project.

Many options have been proposed for repurposing installed oil & gas infrastructure in the Gulf of Mexico. These include aquaculture, seabed mining, sport fishing and a variety of clean energy options. Among the clean energy options are CO2 sequestration, geothermal, wave energy, floating solar and other projects. In Project SHOWPLACE, the focus is limited to clean energy projects, and within that, on wind power generation and hydrogen generation. Further, within the wind-hydrogen space, there are a range of use cases such as combined power and hydrogen export, freshwater export, hydrogen as a long term "battery" to solve wind intermittency issues, storage of hydrogen in subsurface reservoirs etc. Over time, the plan is to evaluate all of these uses cases and expand to the other clean energy options. For Phases 1 and 2, the focus is on two "book end" use cases - power export only, and H2 export only.

The basic ROICE concept in these cases is to install a set of floating or fixed wind turbines around a repurposed offshore platform. The resulting power is either transmitted back to shore as an electric power project or used for a hydrogen project to desalinate seawater, electrolyze the resulting fresh water into hydrogen and oxygen, and transport the hydrogen via existing pipelines to shore. In a power project, the offshore structure is used to house power transmission infrastructures such as converters, substations, and supporting infrastructure. In a hydrogen project, the offshore structure will also house desalination units, electrolyzers, and other balance of plant.

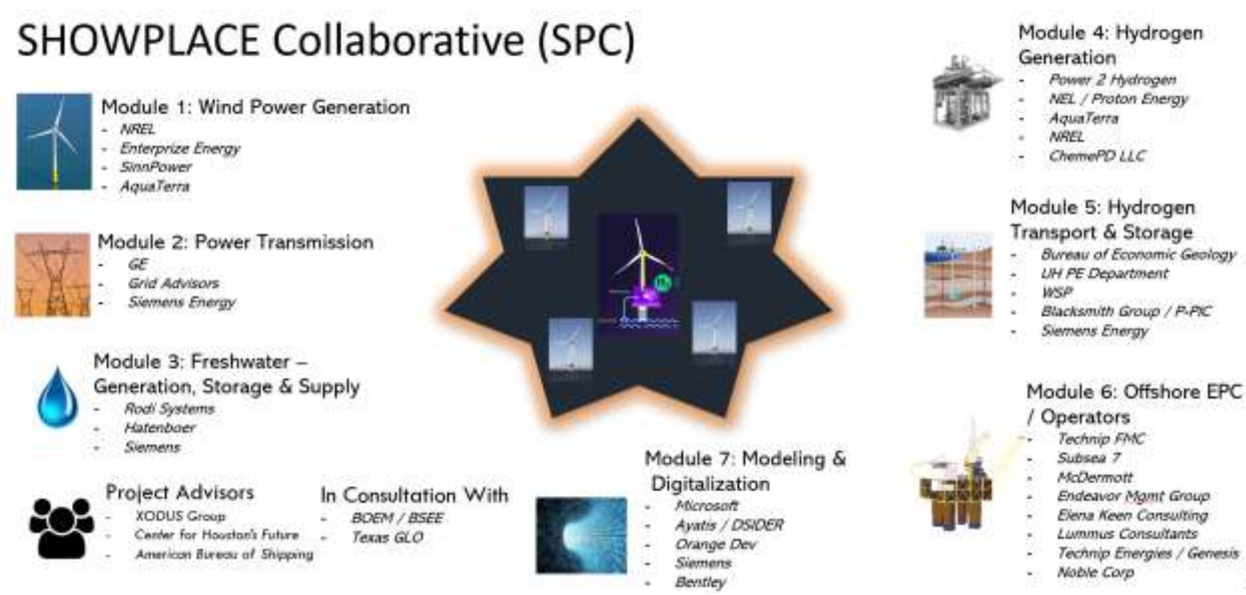


Figure 8: The SHOWPLACE Collaborative

As shown in Figure 8 above, this concept is divided into seven modules, ranging from power generation, transmission, hydrogen generation, storage, and offshore infrastructure repurposing to digital twin modeling. Each module is advised by key experts drawn from the industry, national labs, and academia, listed in the figure above. They form the SHOWPLACE Collaborative or SPC. In addition, regulatory bodies such as BOEM and BSEE are frequently consulted and kept informed. SPC Members provide critical consultation on equipment design, costs, installation methodology and review and approve the model and results. This feedback is obtained through monthly SPC meetings as well as detailed "deep dive" sessions into specific topics.

The SHOWPLACE research team would like to gratefully acknowledge the critical assistance provided by an SPC Member, the XODUS Group, to Project SHOWPLACE. XODUS provided the team with a levelized cost of energy model they had previously built. They trained this research team in understanding the many components and nuances of levelized cost modeling. The ROICE LC model was thus built on a strong foundation, saving many weeks of effort, and allowing a greater focus on the addition of new features such as repurposing and hydrogen production. Further the XODUS team also trained this research team on geospatial mapping and provided the grids and methodology they generated for the Gulf of Mexico.

Phase 1 objectives include the following elements, the results of which are documented in this report:

- Build a UH Energy ROICE Levelized Cost Model (ROICE LC Model) for the US GOM
- Generate heat maps for wind power generation projects and hydrogen generation projects
- Compare repurposing and new build cases
- Examine impact of project scale by modeling a demonstration project and a commercial project
- Generate LC values for each asset in the US GOM
- Develop a shortlist of assets for detailed modeling in Phase 2

In Phase 2, the following elements will be tackled:

- Enhance the ROICE LC Model using advanced digital models
- Switch from Levelized Cost concept to project economic metrics such as NPV and Rate of Return
- Develop conceptual ROICE project designs for shortlisted assets using public domain information
- Work closely with ROICE workgroups to cross-implement findings
- Reach out to Operators and plan for collaboration on future phases.
- Refine the asset shortlist to identify potential demonstration and commercial project locations

The following sections will provide details of the methodology used and results from Phase 1 of Project SHOWPLACE.

III. Data and Methodology

A. Representative Locations

Three representative locations (Table 3) were selected from the nearly 1700 potential sites within the GOM region. These locations will be used to illustrate the diverse range of results generated by the ROICE LC Model. This approach enhances the clarity and understanding of how different factors such as water depth, proximity to shore ports and wind speed interact and influence the outcomes of ROICE projects at these locations. Location A represents assets in the western part of the GOM where wind speeds are highest. Location B represents assets that are close to population and demand centers. Both of these are in relatively shallow waters. Location C represents assets in deeper waters. (Figure 9)

Table 3: Representative Location Attributes

Representative Location Attributes			
Attributes	Location A	Location B	Location C
Latitude	27.80969	28.894146	27.788125
Longitude	-96.78104	-94.704392	-93.188085
Wind Speed (m/s)	7.993989	7.56466	7.372825
Wave Height (m)	1.008131	0.889029	1.111667
Bathymetry (m)	-25.096154	-19.276596	-216.361702
Export Distance (m)	56462.375	55040.804688	243752.09375
Installation Port Distance (m)	27784.0625	59283.199219	254176.3125
O&M port Distance (m)	27784.0625	53109.796875	239840.609375

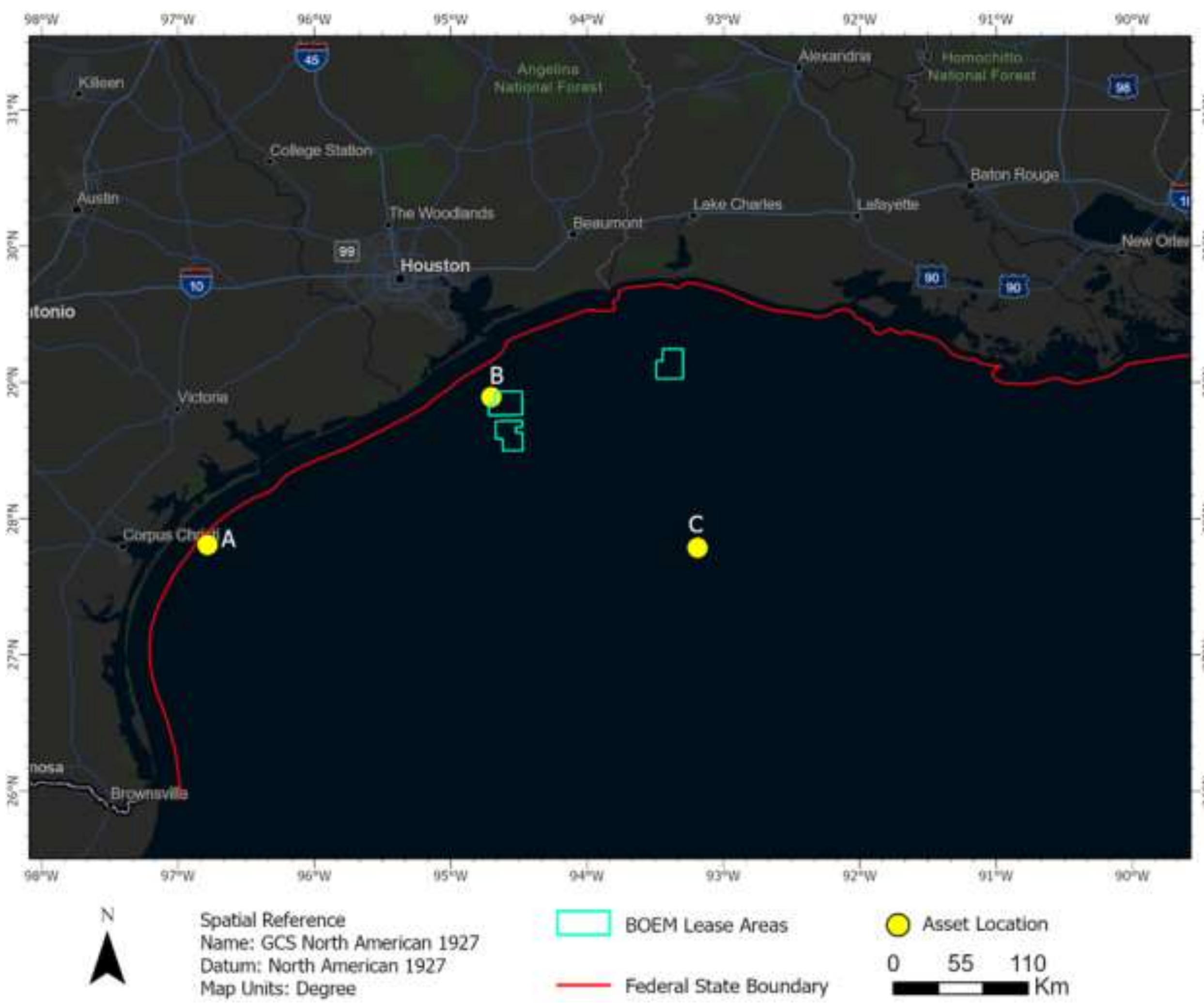


Figure 9: Representative Data Locations

B. Levelized Cost Definition and Utility

The concept of Levelized Costs of Energy (LCOE) provides a way to compare costs across different pathways of energy generation on a common basis. This allows for comparison of different technologies with varying scales of operation, different operating and investment costs, project time periods, etc. (Short, et al. 1995).

The Energy Information Administration (EIA) defines the levelized cost of electricity as the average revenue per unit of electricity generated that would recover the costs of building and operating a generating plant during an assumed financial life and duty cycle. Duty cycle refers to the typical utilization or dispatch of a plant to serve the load (EIA 2022). The lifetime cost of the system includes initial capital cost, maintenance cost, and operational costs (Musial et al. 2020).

In this study, the levelized costs of energy (LCOE) and hydrogen (LCOH) were examined. Several models exist in the literature indicating the lack of a standard definition for LCOE and LCOH. Short, et al. (1995) computed the LCOE with Equation 1 as follows:

$$LCOE = \frac{TLCC}{\sum_{n=1}^{N} \frac{Q_n}{(1+d)^n}}$$

Equation 1

Where:

LCOE = levelized cost of energy

TLCC = total life-cycle cost

Q_n = energy output or saved in year n

d = discount rate

N = analysis period

TLCC is computed as follows:

$$TLCC = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n}$$

Equation 2

Where:

LCOE = levelized cost of energy

TLCC = total life-cycle cost

C_n = cost in period n: investment costs include finance charges as appropriate, expected salvage value, nonfuel O&M and repair costs, replacement costs, and energy costs

d = discount rate

N = analysis period

The Bureau of Ocean Energy Management (BOEM) follows the definition as proposed by Beiter et al. (2016) using Equation 3 (Musial et al. 2020).

$$LCOE = \frac{(FCR\ x\ CapEx) + OpEx}{AEP_{net}}$$

Equation 3

Where:

LCOE = levelized cost of energy

FCR = fixed charge rate (%)

AEP_{net} = net average annual energy production (KWh/year)

CapEx = capital expenditures ($/kW)

OpEx = average annual operational expenditures ($/kW/year)

Here is a brief summary of these different approaches. The Short model discounts the operating costs and the energy output yearly while the Beiter model uses an average OpEx and annual energy production. In addition, the Short model considers salvage value and replacement costs explicitly. The Short model would be used with a known discount rate, while the Beiter model should be used with a known fixed charge rate. Each of these models has its utility. The Beiter model is well suited for a quick computation, while the Short model is more useful when modeling time related variations is important.

The levelized cost equations in the ROICE LC Model is closer to the Short model. The primary difference is that salvage value was not considered since ROICE projects utilize repurposed infrastructure.

C. Power Generation System

1. Overview

For the ROICE use cases examined in Phase1 of Project SHOWPLACE, power is generated via wind turbines situated around the asset being repurposed. The power is then brought back to shore using export cables and tied into the onshore power grid. For a hydrogen project, all of the power generated is sent to the hydrogen plant located on the repurposed offshore asset.

The energy yield of a wind farm is influenced by three primary factors: the characteristics and efficiency of the wind turbine generator (WTG) along with its power curves, wind speeds, and the probability distribution of wind speeds at a specific location. This section provides the details on the power generation system such as design parameters, power generation calculations, capex and opex estimates, installation and maintenance assumptions.

2. Wind turbine generators (WTGs)

The main component of a wind farm is the Wind Turbine generator (WTG). For the ROICE LC Model multiple WTGs ranging from 8 MW to a theoretical capacity of 20 MW have been considered. For this study, a 15-Megawatt Offshore Reference Wind Turbine(Gaertner et al. 2020) defined by NREL and International Energy Association (IEA) was selected.

The theoretical power output of a wind turbine is given by

$$Power\ (W) = \frac{1}{2}\ \rho\ A\ v^3$$

Equation 4

where ρ is the air density in kg/m^3, A is the cross-sectional area swept by the Blades of the Wind turbines in m^2 and v is the wind velocity in m/s^2. (Manwell et al. 2010)

This equation is used to generate a power curve for the WTG, representing the relationship between the wind speed and the electrical power generated by the turbine. Typically, the power output of a WTG increases as the wind speed increases up to its maximum rated generational capacity. Beyond which, the power output levels off, and the turbine operates at its maximum capacity (Figure 10).

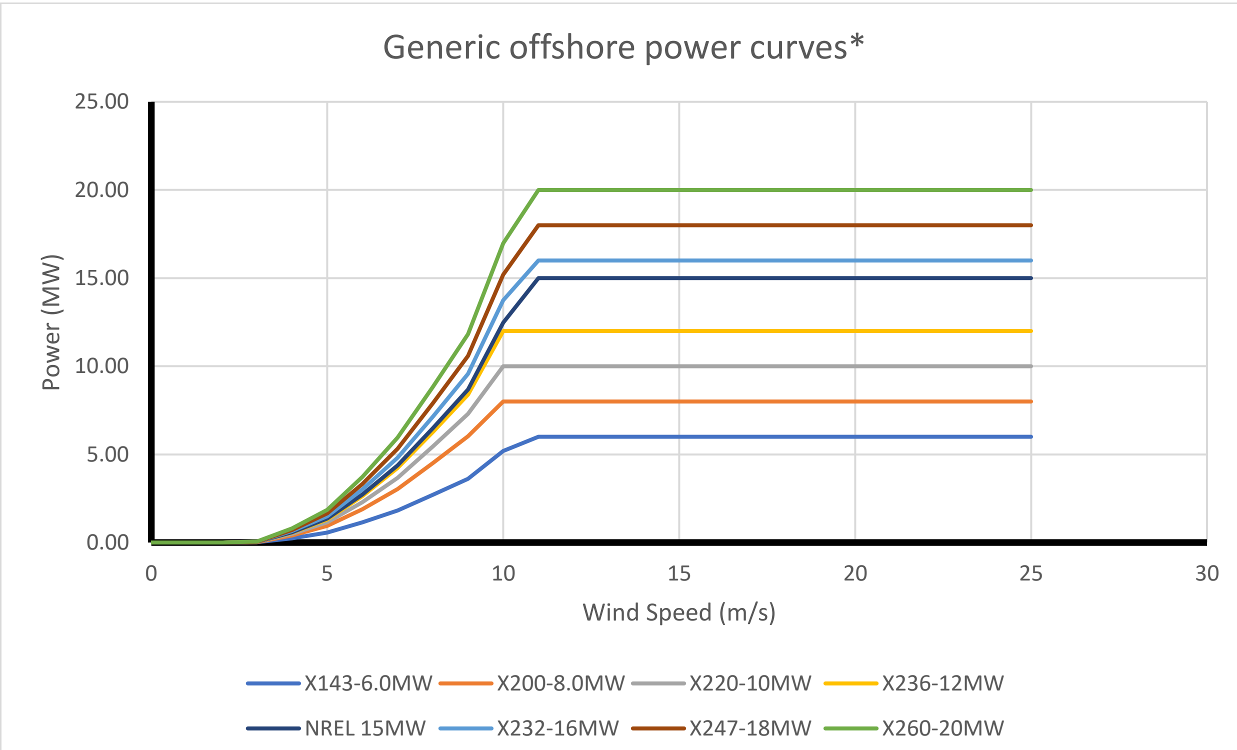


*Figure 10: Generic Offshore Power curves. * All performance data calculated using the Capacity Factor provided by NREL 15 MW reference turbine performance data and are scaled up or down respectively*

To model different WTG capacities, such as 6 MW, 8 MW, 10 MW, etc., the NREL 15 MW model's power curve as a reference to simulate the power curves was used for the respective capacities. First, the capacity factor of the NREL 15-Megawatt reference turbine was calculated using Equation 5

$$C_p = \frac{Actual\ Power}{\frac{1}{2}\ \rho\ A\ v^3}$$

Equation 5

where actual power is the power output of the WTG at a particular wind speed derived from the power curve and where ρ is the air density in kg/m^3, A is the cross-sectional area swept by the Blades of the Wind turbines in m^2 and v is the wind velocity in m/s. C_p usually range from 0.05 to 0.5. Then the power curve for different WTG was obtained using Equation 6

$$P = C_p * \frac{1}{2} \rho A v^3$$

Equation 6

3. Wind Speed and Weibull Distribution

As is well known, wind speeds are not constant and vary over time at any given location. The Weibull distribution (Equation 7)

$$f(x; c, k) = \frac{k}{c}\left(\frac{x}{c}\right)^{k-1} e^{-(x/c)^k}$$

Equation 7

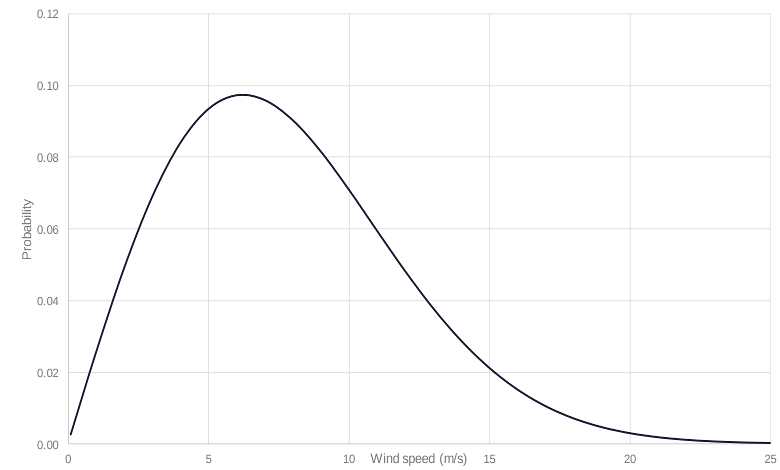
Is commonly used to account for the intermittency of wind. The Weibull distribution is characterized by two parameters: the shape parameter (k) and the scale parameter (c). The shape parameter defines the shape of the curve, indicating the likelihood of different wind speeds occurring, while the scale parameter determines the location of the peak of the curve. By applying a Weibull distribution to the average wind speed data measured at a particular site, it becomes possible to estimate the probability of different wind speeds occurring at the site. This information is crucial for accurately predicting the average energy output of a wind farm. (Manwell et al. 2010).

4. Final Annual Energy Output

As shown in Figure 11 below, the Weibull probability distribution was taken and multiplied with the power curve of the WTG selected to generate a gross annual energy (MWh) of each turbine. To obtain the net annual energy delivered to the onshore substation (MWh), various efficiency factors such as availability factor, electric system losses, electrical consumption of ballasting system losses, high wind hysteresis and active ballast losses, and other smaller losses, such as wake effects, shear, turbulence etc. was considered. This net annual energy (MWh) is then discounted over the life of the project to obtain the term $\sum_{n=1}^{N} \frac{Q_n}{(1+d)^n}$ used in the LCOE Equation 2.

The ratio of the net annual energy to the theoretical power output is called the Capacity Factor for the project at the given location. The capacity factor thus expresses the WTG system's efficiency in converting variable wind energy into electrical power at different wind speeds. For wind power projects, the capacity factor typically ranges between 30 to 50%.

Annual Energy Calculation



Wind Speed (m/s)	Probability	Power (MW)	Annual energy (MWh)
0.1	0.3%	0.00	0
1	2.5%	0.00	0
2	4.9%	0.00	0
3	6.9%	0.04	22
4	8.4%	0.59	431
5	9.4%	1.36	1111
6	9.7%	2.73	2327
7	9.6%	4.37	3677
8	9.0416%	6.48	5132
9	8.1667%	8.68	6208
10	7.0995%	12.47	7753
11	5.9543%	15.00	7824
12	4.8263%	15.00	6342
13	3.7857%	15.00	4974
14	2.8766%	15.00	3780
15	2.1193%	15.00	2785
16	1.5147%	15.00	1990
17	1.0509%	15.00	1381
18	0.7081%	15.00	930
19	0.4635%	15.00	609
20	0.2948%	15.00	387
21	0.1823%	15.00	240
22	0.1096%	15.00	144
23	0.0641%	15.00	84
24	0.0364%	15.00	48
25	0.0202%	15.00	26
>25	0.0%	0	0

Figure 11: Weibull Distribution and Annual Average Yield

5. Electrical Infrastructure

The calculation of the levelized cost of a wind farm project necessitates careful accounting of the various components of electrical infrastructure. This includes array cables, which play a critical role in interconnecting the wind turbines and linking them to the Off-Shore Substation (OSS). The OSS is responsible for converting the generated power into a suitable form for transmission to the On-Shore Substation, carried by Export cables. The ROICE LC model can account for losses associated with each individual component or incorporate a gross percentage loss in overall production to accurately address energy losses.

a) Array Cables

Array cables interconnect multiple wind turbines and link them to the offshore substation (OSS). Typically, these cables are designed with a voltage rating of 33kV. However, considering the prevailing supply market and availability, 66kV cables was employed, which offer the advantage of enhanced capacity per cable, leading to reduced cable lengths and component costs associated with the OSS.

b) Offshore Substation (OSS) and Transmission

Offshore substations play a crucial role in wind farm projects by stepping up the voltage from the site distribution level (in the case, 66kV) to a higher voltage level. The selection of the specific transmission voltage for the substation depends on various factors, including the capacity of the grid it will be connected to and the regulatory requirements of the particular region.

One of the critical decisions in the project revolves around choosing between a High Voltage Alternating Current (HVAC) or High Voltage Direct Current (HVDC) system for the offshore substation and transmission. Several factors come into play when making this determination. the ROICE LC Model considers an HVAC system for installations less than 80km from shore and a project capacity of 500MW or lower. The HVAC system offers the advantage of reduced cost and design complexity. On the other hand, for installations beyond 100km and/or with a project capacity exceeding 500MW, an HVDC transmission system becomes necessary. This is because the HVDC system is more efficient with increased distance and power capacity.

To address the range between 80km and 100km, where an increase in reactive power from the HVAC system is observed but justifying the additional cost (approximately five times) of an HVDC system is challenging, a Reactive Power Compensator (RPC) was incorporated into the infrastructure. The purpose of the RPC is to compensate for the reactive power being produced, helping to mitigate the reactive power issues associated with the HVAC system at this distance range. Table 4 shows the logic that is implemented in the ROICE LC Model. This information helps identify the nearest suitable On-Shore export point that connects the wind farm to the grid along the Gulf of Mexico coastline. Need to add units to distance to Onshore in the table below.

Table 4: Conditions for Offshore Substation

Conditions for Offshore Substation							
OSS	Distance to OnSH. (KM)		Project Capacity (MW)		Cable Voltage (kV)	Cost of OSS
HVAC	<	80	</=	500	132/220	As per Normal
RPC	<	100	</=	500	220	Additional to HVAC
HVDC	>/=	100			320	As per Normal

c) Export Cables

Export cables are essential high voltage cables used to transmit power from an Off-Shore Substation (OSS) to an On-Shore Substation. Within the ROICE LC Model, three types of export cables are considered. The first type consists of two three-phase AC cables, rated at 132kV and 320kV respectively, enabling an export capacity of 275MW per cable. The second type is a DC cable rated at 220kV, with an export capacity of 925MW per cable. The length of these export cables is determined based on a Geographic Information System (GIS) variable known as "Distance to grid connection point." Onshore Substation

d) Onshore Substation

The primary role of the On-Shore Substation is to convert the incoming power from the export cables into a suitable form that can be supplied to the grid. In the ROICE LC Model, various export cable ratings (132kV, 320kV, and 220kV) was incorporated and a range of transmission voltages for the Onshore Substation (115kV, 183kV, 161kV, 230kV, 345kV, 500kV, or 765kV) was considered. For the purpose of the Phase 1 work, an export voltage of 345kV was specifically considered.

e) Losses

Electric losses play a crucial role in the calculation of the Levelized Cost of Energy (LCOE) as they directly impact the total yield (Q_n) in Equation 1. Based on recommendations from transmission experts within the SPC, an overall loss of 5% against the Gross Annual Yield was implemented, encompassing all electrical infrastructure components. However, the engine also offers the flexibility to toggle and consider losses from individual components such as array cables, export cables, Off-Shore Substation (OSS), On-Shore Substation, and transformers, among others.

6. Capital Expenditures (CAPEX)

a) *Wind Turbine Generator (WTG) and Offshore Substation (OSS)*

WTG costs are recognized as the most dynamic cost element in the ROICE engine. Due to the rapid pace of technological advancements, multiple vendors, and varying design capacities, finding a generalized cost or $/MW for wind turbine installations can be challenging. As previously mentioned, NREL's 15 MW wind turbine design is considered. To estimate the costs associated with such designs, recommendations from the SPC members have been taken, including General Electric (GE). Based on these considerations, a cost of $2,000,000 per MW of installed WTG capacity was assumed. Table 2 shows the WTG Capex for the two different project sizes examined in this study – 105 MW (Demonstration Project) and 435 MW (Commercial Project). Table 5 showcases a reduced per MW cost of installed Wind Turbine Generator (WTG) capacity, attributable to the inclusion of a cost factor for Economies of Scale as discussed late in section e)III.C.6.e)

Table 5: WTG CAPEX

Wind Turbine Generator CAPEX (Non-Location Dependent / Non-Repurposed)	
105 MW	435 MW
$195,300,000	$809,100,000

The Transmission Cost Estimation Guide from MISO was utilized (*Transmission Cost Estimation Guide For MTEP22*, 2022) to estimate the overall cost of the OSS. OSS costs for the three different representative locations mentioned earlier are shown in Table 6.

Table 6: OSS CAPEX

Off-Shore Substation CAPEX (Non-Repurposed)					
Location A		Location B		Location C	
105 MW	435 MW	105 MW	435 MW	105 MW	435 MW
$3,813,600	$15,799,200	$3,813,600	$15,799,200	$22,881,600	$94,795,200

b) *Foundations and Installations*

Three different types of foundations for wind turbine generator (WTG) installations was considered, depending on the water depth at the installation site.

- Monopole: Utilized in water depths up to 50 meters, at a unit cost of $7,800 per MW per meter of depth.
- Jacket: Utilized in water depths ranging from 50 to 80 meters, at a unit cost of $9,500 per MW per meter of depth.
- Floating Foundation: Utilized in water depths beyond 80 meters up to 1000 meters, at a unit cost of $520,000 per MW. The predominant portion of the cost associated with floating foundations is not contingent on the water depth.

The ROICE LC Model does not calculate LC's where the water depth exceeds 1000 meters, as these projects are not likely to be economic.

The installation costs for both WTG and OSS are determined using vessel rates and travel time, as illustrated **Error! Reference source not found.** The distance to the nearest Installation port, obtained from a Geographic Information System (GIS) datapoint, is utilized to calculate both travel time and installation time. The costs associated with installing the foundations for both WTG and OSS are estimated in a similar manner, considering the specific requirements of each type of foundation.

Table 7: Vessel Rates and Installation Duration

Foundation Vessel Values					
Foundation Type	Vessel Type	Vessel AVG Speed (m/s)	Vessel Day Rate ($)	Travel Time (working days)	Installation Duration (days/foundation)
Floating	Anchor Handler	4	$48,000.00	0.9	1.5
Jacket	Cranel Vessel	4	$200,000.00	0.9	2.5
Monopile	Jack-Up	4	$100,000.00	0.9	0.5
Jacket (OSS)	Crane Vessel	4	$250,000.00	0.9	2.5
WTG / OSS Vessel Values					
Foundation Type	Vessel Type	Vessel AVG Speed (m/s)	Vessel Day Rate ($)	Travel Time (working days)	Installation Duration (days/foundation)
Floating	Anchor Handler	4	$250,000.00	0.9	1.5
Jacket	DSV	4	$193,750.00	0.9	2.5
Monopile	DSV	4	$193,750.00	0.9	0.5
Jacket (OSS)	Crane Vessel	4	$250,000.00	0.9	2.5

Table 8: WTG Foundation CAPEX

Wind turbine Generator Foundations CAPEX (Non-Repurposed) ($)						
	Location A		Location B		Location C	
	105 MW	435 MW	105 MW	435 MW	105 MW	435 MW
Foundation	Monopile	Monopile	Monopile	Monopile	Floating	Floating
New Build	32,889,810	136,257,786	27,843,098	115,349,979	87,835,908	363,891,617

Table 9: OSS Foundation CAPEX

OSS Foundations CAPEX			
	Location A	Location B	Location C
New Build	$10,472,667	$8,403,284	$163,525,046
Repurposed	$1,301,610	$1,438,325	$2,284,215

c) Onshore Substation

The On-Shore Substation (OSS) plays a crucial role in converting the power received from the export cables into a suitable form for transmission to the grid, and its cost is an important factor in calculating the overall expenses of the wind farm project. Various components contribute to the overall cost of an OSS, but the main component with a significant cost impact is the transformers. Given the different ratings for the onshore grid connection point and the three different ratings for the export cables, a total of 21 combinations of transformers is available.

To estimate the cost of transformers, the MISO report (Transmission Cost Estimation Guide For MTEP22 2022) was relied upon, which considers the MVA (Mega Volt-Ampere) capacity of the project and factors in additional cost considerations for the different components.

Table 10: On-Shore Substation CAPEX

On-Shore Substation CAPEX (Non-Repurposed)					
Location A		Location B		Location C	
105 MW	435 MW	105 MW	435 MW	435 MW	105 MW
$2,037,651	$4,204,431	$2,037,651	$4,204,431	$19,068,000	$78,996,000

d) Cables

The cost of cables in the wind farm can be divided into two sub-costs: array cables and export cables.

The cost of array cables largely depends on their voltage rating. Wind farm projects can choose between lower-rated and cheaper cables, using more of them, or opt for higher-rated and higher-capacity 66kV cables, reducing the total number of components required. For the analysis, 66kV array cables at a cost of $1000 per meter is utilized.

To calculate the total length and cost of array cables required for the wind farm project, a grid pattern layout is adopted for the Wind Turbine Generators (WTGs), with 1200 meters (or 5 Wind turbine Diameters) in one direction and 2400 meters (or 10 wind turbine diameters) in the other. Assuming the Off-Shore Substation (OSS) is at the center of the wind farm, this serves as a reference point for the cable length calculations. The model optimizes the number of WTGs that can be connected to a single cable, reducing overall cable length and costs. By calculating the cable length from each WTG to the OSS, the total number of cables required to connect all WTGs can be determined, providing a comprehensive estimate of the array cable length and cost for the project.

Table 11: Array Cables CAPEX

Array Cables CAPEX (Non-Repurposed)					
Location A		Location B		Location C	
105 MW	435 MW	105 MW	435 MW	105 MW	435 MW
$9,926,250	$40,955,192	$9,850,596	$40,640,936	$12,629,064	$61,748,979

The cost of export cables is relatively straightforward to calculate. A cost of $2500/meter for an HVAC export cable and $1100/meter for a HVDC export cable is assumed. Using the previously mentioned

Distance to Grid Connection variable obtained from the GIS dataset, the length of such cables is estimated. This results in the following export cable capex for the three representative locations.

Table 12: Export Cable CAPEX

Export Cables CAPEX (Non-Repurposed)					
Location A		Location B		Location C	
105 MW	435 MW	105 MW	105 MW	435 MW	105 MW
\$141,155,938	\$141,155,938	\$137,602,012	\$137,602,012	\$271,041,296	\$271,041,296

e) Cost Factors and Economies of Scale

To account for the dynamic nature of component costs over time, the ROICE LC Model considers several cost factors, such as learning rates and economies of scale, to enhance precision in cost estimations.

Regarding learning rates, different types of foundations, especially floating foundations, may improve and become more cost-effective over time due to advancements in technology and increased experience in their installation. In the model the floating foundations are considered to have a Learning rate factor of 0.83 whereas monopile foundations, which is a well-established technique have a learning rate factor of 1.00. To incorporate learning rates, the total CAPEX (Capital Expenditure) of installing a specific foundation type, for instance, floating foundations for a WTG is multiplied with its respective Learning Rate factor.

Similarly, economies of scale play a significant role in large-scale projects. As wind farm projects can leverage their purchasing power and negotiate more favorable procurement and installation contracts due to their size, this effect is accounted for by introducing an Economies of Scale factor that multiplies the general overall CAPEX. Table 13 shows the factors being used by the model.

Table 13: Economies of Scale Factor

Economies of Scale		
Type	Rate	Factor
General	4.2%	0.93
OPEX	4.2%	0.93

Additionally, the Jones Act must be considered, which requires the use of US-built and flagged vessels for installations in the Gulf of Mexico (GOM). This constraint introduces the need for feeder vessels, which assist in the installation of various components and add an additional cost to the vessel-related expenses mentioned earlier.

By incorporating these cost factors, the ROICE engine becomes more precise in estimating the total costs associated with wind farm projects, accounting for the evolving nature of expenses over the project's duration and the specific conditions of the Gulf of Mexico region.

f) Overhead Capital Costs

It's important to account for various overhead capital costs when estimating the total capital expenditure (CAPEX) of a wind farm project. These overhead capital costs include expenses related to Contract for Difference (CFD), Front-End Engineering Design (FEED), Project Management, Design and Engineering, Consenting, Lease Price, Insurance, Contingency, Overheads, and other related items.

To calculate the total overhead capital cost, each of these items is expressed in $/MW. The project capacity is then used to determine the cumulative cost for each category. The overhead capital costs are then added to the project CAPEX to provide a comprehensive estimation of the total CAPEX required for the wind farm project. Typical overhead cost distribution is shown in Figure 12.

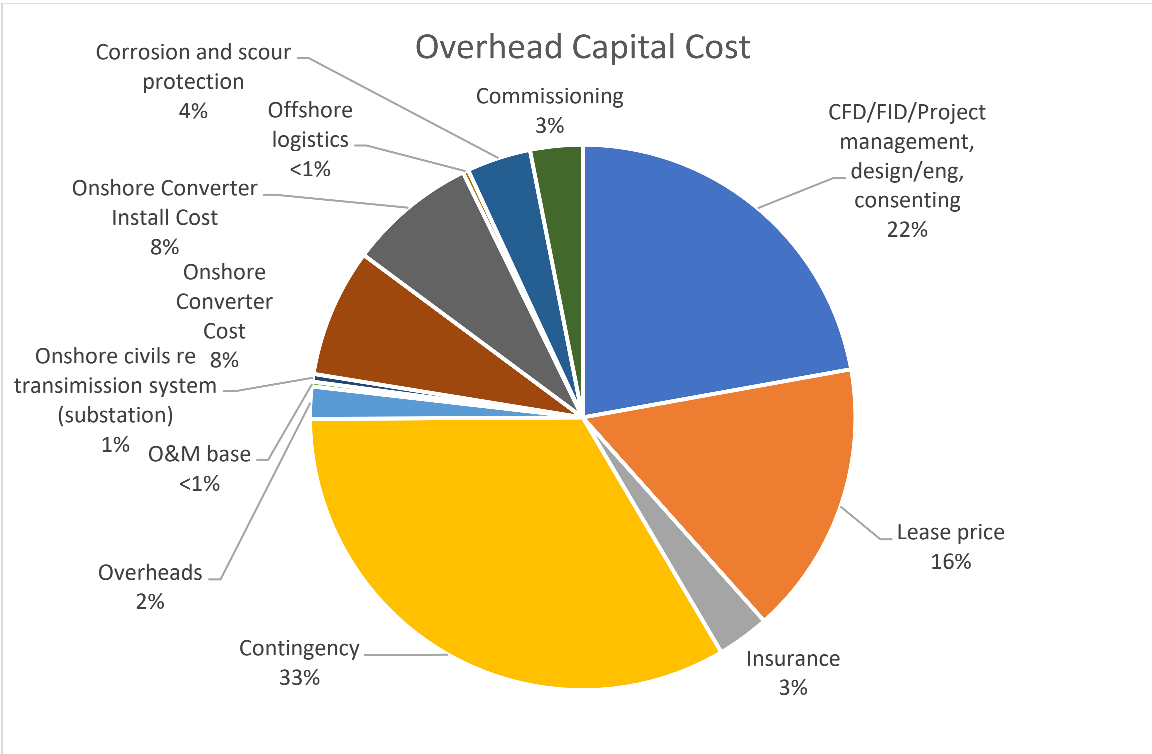


Figure 12: Overhead Capital Cost Breakdown

g) Power Production Results

The resulting net power outputs for the three representative locations and two project sizes are provided in Table 14 below. The average wind speed is location dependent, hence the variation in results for the three different locations. The capacity factor for the US GOM ranges from 30 to 45% - largely driven by wind intermittency.

Table 14: Power Generation and Other Key Results

Power Generation and Other Key Results						
	Location A		Location B		Location C	
	105 MW	435 MW	105 MW	435 MW	105 MW	435 MW
Gross Power Production (MWh/year)	392,383	1,625,587	407,815	1,689,518	392,383	1,625,587
Electrical Losses (MWh/year)	53,908	284,821	48,071	264,422	53,907	284,821

Net Annual Energy at On-Shore Sub (MWh/year)	338,475	1,340,766	359,744	1,425,096	338,476	1,340,766
Capacity Factor	36.8%	35.2%	39.1%	37.4%	36.8%	35.2%

7. Operating Expenditures (OPEX)

a) Fixed and Variable Operations and Maintenance (O&M) Costs

In the analysis, the OPEX is divided into 3 major components. Annual O&M Costs, Annual Preventive Maintenance Costs, and Decommissioning Costs. (Figure 13) NREL's 2021 Cost of Wind Energy report (Stehly and Duffy 2021) provides valuable data on each of these cost categories.

Annual O&M costs are proportional to the overall capacity of the project. This cost encompasses various expenditures including salaries, fees incurred at the O&M port, as well as project-related insurance expenses, all quantified in terms of dollars per megawatt ($/MW).

Annual Preventive Maintenance costs represent the expense associated with maintaining each individual turbine unit, ensuring a consistent production rate from these units over the life of the project. It is proportional to the number of wind turbines deployed for the project, all quantified in terms of dollars per turbine. For instance, transitioning from 15 MW to 20 MW WTG units results in a reduction in the total number of turbines required, subsequently leading to a decrease in the Annual Preventive Maintenance cost. Additionally, this cost parameter is influenced by the geographical location of the project within the GOM, in the form of supplementary expenses for vessels and crew when the project is situated at a greater distance from the coastline.

Decommissioning Costs reflect the final cost of decommissioning the ROICE project components. Note that this is different from the decommissioning costs incurred at the start of the ROICE projects to remove the oil & gas related equipment. The assumptions on this O&G decommissioning are discussed in detail in section III.E. By modeling ROICE equipment decommissioning into the ROICE project OPEX, an assumption is essentially made that the project is going to put some money aside each year to pay for the decommissioning at the end of the project's life.

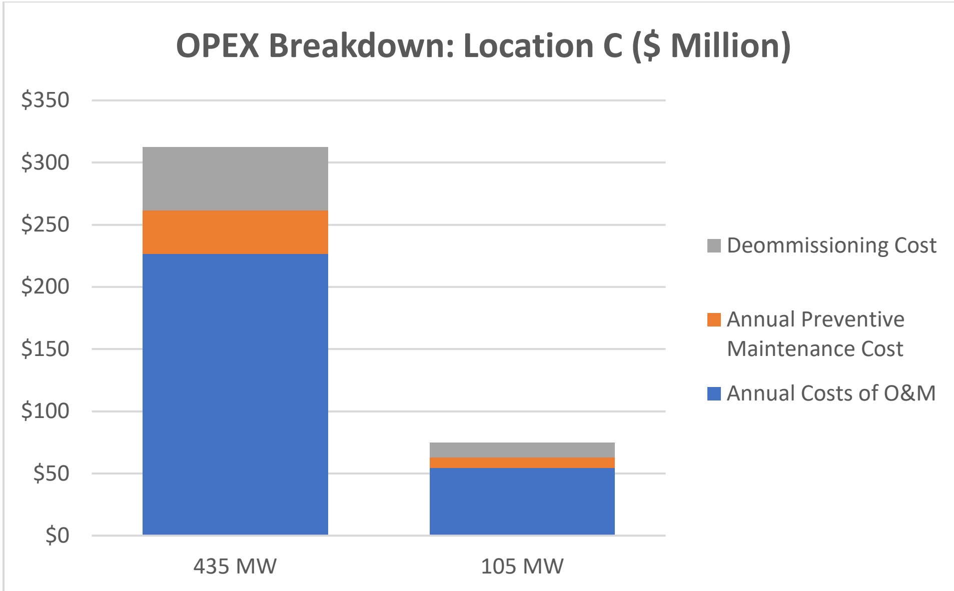


Figure 13: OPEX Breakdown Location C

b) O&M Strategy and Factor

Understanding the impact of different distances and varying sea conditions on The Annual Preventive Maintenance cost and different Operations and Maintenance (O&M) strategies is crucial for accurately estimating OPEX in offshore wind projects. Table 15 illustrates the different O&M strategies, their corresponding maximum distance from port they can serve, the wave height (Hs) limit they can operate in, and the Strategy Cost Factor associated with each strategy provided to use by the XODUS group. Table 16 shows the O&M strategy picked by the ROICE LC model for each location. Annual Preventive Maintenance cost showed in Figure 13 already has the O&M Strategy cost factored in.

Table 15: O&M Strategy Cost Factor

Service Vessel Limits			
O&M Strategy	Max Distance from port (m)	HS limit (m)	O&M Strategy Cost factor
CTV	70000	0.88	1
CTV+	70000	3	1.1
SES	150000	3	1.25
SOV	3000000	3	1.5

Table 16: O&M Strategy for Each location

O&M Strategy for Each location		
Location A	Location B	Location C
CTV +	CTV +	SOV

D. Hydrogen Generation System

1. Overview

Similar to the power generation system, calculating the Levelized Cost of Hydrogen (LCOH) involves assessing various factors related to infrastructure, CAPEX, OPEX, and hydrogen production volumes over the project's lifespan. The LCOH equation utilized is analogous to the one used previously (Equation 1) for calculating the Levelized Cost of Energy (LCOE). To determine the cost elements going into the LCOH, the CAPEX associated with the hydrogen production infrastructure is considered, including the costs of equipment, facilities, and other necessary components. Operating costs, such as maintenance, labor, and utilities, are also considered. Additionally, the hydrogen production volumes are calculated and discounted for use in the denominator of the LCOH calculation.

2. Infrastructure and CAPEX

In all the hydrogen generation cases, the power input is assumed to come from a newly installed wind turbine generator (WTG) system similar to those discussed in the Power Generation System section above. All of the power generated by the WTG system is assumed to be used for hydrogen generation. The same two sizes of power generation (105 MW and 435 MW) supporting the equivalent hydrogen generation systems are assumed. After providing power to all the other system components such as the desalination units, compressors and balance of plant, the 105 MW system generates sufficient power for a 40 MW electrolyzer stack. Similarly, the 435 MW system supports a 180 MW electrolyzer stack. Other than the cost of export cables to bring the power to shore, the entire power system capex will need to be added to the hydrogen generation capex to obtain total capex for hydrogen projects.

In the analysis, the Off-Shore Substation was replaced with an Offshore Hydrogen Production System (OHP) specifically designed to produce hydrogen. The OHP is equipped with all the necessary components, such as desalination units, compressor units, and most importantly, electrolyzer units, to facilitate hydrogen production. Figure 14 shows the breakdown of the component cost.

The full Hydrogen Generation System incorporates all the costs associated with the production of hydrogen. (Figure 14) Besides the OHP, it also includes costs related to pipelines for transportation, the foundation on which the OHP is installed, and all other essential components required for efficient hydrogen generation. For the OHP foundation and installation, an assumption is made that this is equivalent to the cost of the OSS foundation and installation as given in section III.C.6.b) for a power generation system. This is based on the similarity of the foundation requirements for both the OHP and the OSS.

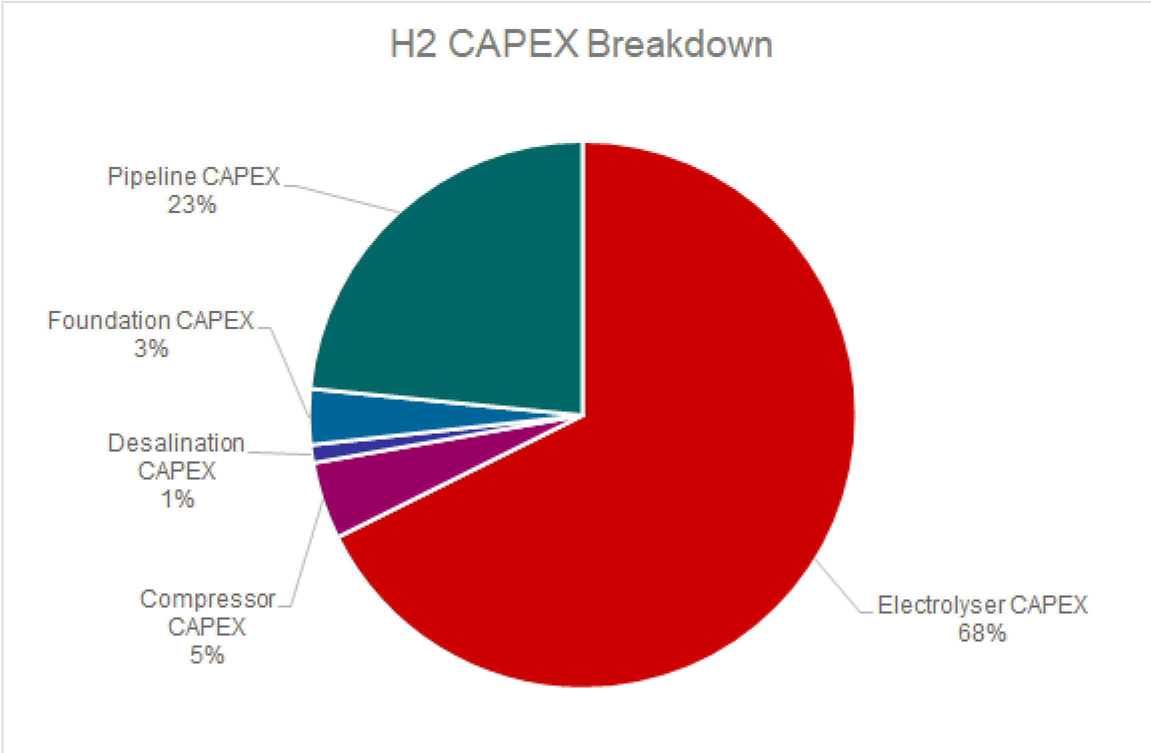


Figure 14: H2 CAPEX breakdown

a) Electrolyzer unit

In the OHP system, the electrolyzer unit is a crucial component responsible for splitting water into hydrogen and oxygen using electricity from the wind farm. To ensure accurate hydrogen production efficiency, industry-standard conversion rates is relied on, informed by SPC members such as Nel and P2H2. For this project, a Proton Exchange Membrane / Polymer Electrolyte Membrane (PEM) electrolyzer solution was chosen due to its compactness and heat efficiency, despite being somewhat more expensive than other options like Alkaline Electrolyzer. Given space limitations on offshore structures, especially the repurposed ones used in ROICE projects, an assumption was made that compactness was desired over cost-effectiveness. For the project, a semi-modular unit design with a capacity of 20 MW is used. However, it is essential to note that the electrolyzer assembly can be built using smaller units, with each unit as small as 1.25 MW, selected and optimized for each project size. The cost estimation (Table 17) for the electrolyzer was sourced from a comprehensive comparison study conducted by one of the SPC members, AquaTerra. This study systematically evaluated various Hydrogen production pathways such as Alkaline, PEM, AEM and SOEC.

Additionally, guidance from SPC members and industry experts regarding Hydrogen generation indicates that electrolyzers can be operated at as low as 10% of its rated capacity and can be overclocked to as much as 160% of its rated capacity. This should help mitigate the effects of wind intermittency experienced by the power generation side of the project. No further modifications to the equipment were assumed to be needed to account for intermittency.

Table 17: Electrolyzer CAPEX

Electrolyzer CAPEX (Non-Location Dependent / Non-Repurposed)	
105 MW (40 MW H2 Production)	435 MW (180 MW H2 Production)
$48,000,000.00	$216,100,000.00

b) Desalination Unit

ROICE projects' offshore location has the advantage of constant and abundant access to seawater that can be desalinated into fresh water for the electrolyzer. For the desalination unit, PureFlex™ SWRO UPW Modular Ultra Pure Water Treatment Systems from RODI System (Lueck 2022) is considered. In the ROICE LC Model, the costs associated with different models of the water treatment system (Table 19), available through RODI have been built in. That can be selected based on the size of the hydrogen production project. These are listed in Table 19 which shows the resulting desalination capex for the two project sizes considered in the study.

Table 18: Desalination Units

Desalination Units (Rodi System)			
Water Rate (m^3/h)	Desalination Units	CAPEX ($ K)	OPEX ($/m^3)
1.25	PF-SWUPW-125	520	1.12
2.5	PF-SWUPW-250	580	0.78
5	PF-SWUPW-500	840	0.59
12.5	PF-SWUPW-1250	1200	0.43
25	PF-SWUPW-2500	1670	0.36
75	PF-SWUPW-7500	3400	0.31
125	PF-SWIPW-12500	4400	0.32

Table 19: Desalination CAPEX

Electrolyzer CAPEX (Non-Location Dependent / Non-Repurposed)	
105 MW (40 MW H2 Production)	435 MW (180 MW H2 Production)
$1,200,000	$3,400,000

c) Compressor Unit (Onshore)

The hydrogen (H2) produced by the electrolyzer exits at a pressure of 30 bars and a temperature of 50 degrees Celsius. As discussed in section 4 below, hydrogen is assumed to be transported to shore using existing oil or natural gas pipelines. Most long-distance pipelines in the US GOM or 12' or greater in diameter. At this size, 30 bar is sufficient to bring the hydrogen to shore. This is discussed in greater detail in section 4 below. However, before being connected to the main "truck line" onshore, the hydrogen is assumed to be compressed to 100 bars. To estimate the cost of the compressor required for this task, guidance from the SPC member from Siemens was received. Siemens internal design tools were employed to develop a model incorporating cost and power factors. The factors used in the ROICE LC Model to determine the cost of the compressor are shown in Table 20. The resulting compression costs for the two typical project sizes used in this study are shown in Table 21. As noted, these costs are not location-dependent and are non-repurposed, i.e., will be needed for either a repurposing project or a new-build one.

Table 20: Compression Cost Assumptions, and a sample calculation

Compression Cost Assumptions		
Flowrate (m^3/h)	Power Factor (hp)	Cost Factor ($)
<50	47.45	3700
>50	35.83	5580
Compression Cost Calculations		
Flow Rate	Power Required	Total Cost
72.52	3441	M$12.73

Table 21: Compression CAPEX

Compression CAPEX (Non-Location Dependent / Non-Repurposed)	
105 MW (40 MW H2 Production)	435 MW (180 MW H2 Production)
M$3.85	M$14.57

d) Pipeline

For a new build project, an assumption is made that a new pipeline is installed to bring the hydrogen to shore. For a ROICE project, repurposing of an existing pipeline for hydrogen transportation is assumed.

For a new-build hydrogen generation system, these pipelines need to be designed considering several parameters such as potential hydrogen embrittlement and lower operating temperatures compared to natural gas pipelines. Additionally, right of way and related costs must be accounted for in order to assess the economics properly. To estimate the cost of such pipelines, the following formulas (Table 22) from the Hydrogen Delivery Scenario Model (HDSAM) (Department of Energy, 2022) by the NREL are used. The provided costs pertain to onshore pipelines and are expressed in terms of 2007 dollars. To ensure relevance to the current year, these costs have been subsequently projected and modeled to reflect 2023 dollars, accounting for inflation and economic shifts over time. Moreover, the supplementary expenses associated with installing pipelines subsea have been incorporated into the installation costs allocated to the OHP.

Table 22: Pipeline CAPEX formulas

Pipeline CAPEX Formulas	
Component	Equation
Transmission Pipeline Material	1.1 * 1.176 / 1.220 * ([870.65 * (Diameter, in.)2 – 13,054 * (Diameter, in.) + 152,684] * (Length, miles))
Transmission Pipeline Labor	1.1 * 1.031 / 1.071 * ([-51.393 * (Diameter, in.)2 + 43,523 * (Diameter, in.) + 16,171] * (Length, miles))
Transmission Pipeline Miscellaneous	1.1 * 1.122 / 1.115 * ([303.13 * (Diameter, in.)2 + 12,908 * (Diameter, in.) + 123,245] * (Length, miles))
Transmission Pipeline Right-of-Way	1.1 * 1.122 / 1.115 * ([-9E-13 * (Diameter, in.)2 + 4,417.1 * (Diameter, in.) + 164,241] * (Length, miles))

Repurposing existing pipelines for hydrogen transport is still an area of research and further study. There are four potential transmission modes of hydrogen using repurposed oil and gas pipelines. The first is via coating the insides of the oil or gas pipeline with a material such as ceramic or copper to mitigate hydrogen leakage and embrittlement. This has been demonstrated in the lab, but pilot and commercial scales are yet to come. (Ahmadi et al., 2021; Boes & Züchner, 1976)

Delivery of the material to coat the pipeline remains a challenge. The second option is pipe-in-pipe solution with a hydrogen-rated pipeline inside an existing oil or gas pipeline. Costs related to pipe in pipe or relining options need to be considered as well as the mechanical constraints of running a length of pipe the required distance to shore. Blending hydrogen with natural gas such as methane can be an option where methane pipelines are in service. A 20% blend seems to be viable without the need for replacement of the pipeline or related infrastructure according to Melaina et al. (Melaina et al., 2013).

A final option is to transport H_2 in existing crude oil or natural gas and particularly methane pipelines at optimal operating conditions with minimal repurposing. Air Liquide has successfully achieved the transmission of H_2 in its pipeline at a pressure of 1400 psig (Air Liquide, 2005). This last option is assumed for the screening work done in Phase 1 of the study since even for the larger 435 MW project, the hydrogen production throughput through the pipelines are a small fraction of what the pipelines are rated to carry.

However, there will still be some costs associated with inspecting the pipeline, restoring abandoned pipelines, and other work needed to put these pipelines back in service. To account for these costs, a repurposing cost equivalent to 35% of the cost of a new pipeline for ROICE projects is included. Table 23 shows a comparison of these costs for the three representative locations.

Table 23: Pipeline CAPEX

Pipeline CAPEX (M$)			
	Location A	Location B	Location C
New Build	$74.84	$72.96	$323.09
Repurposed	$26.19	$25.53	$113.08

e) Hydrogen Production Specifications and Results

To estimate hydrogen production, the following specifications (Table 24) provided by SPC members NEL and AquaTerra is used:

Table 24: H2 Production Specifications

H2 Production Specifications	
Electrolyzer efficiency	50.097 kWh consumed per 1 kg of H2 Produced
Output pressure	30 bar
Fresh water consumption	0.9 liters/nM^3 ~ 10.7892 liters/kg
Electrolyzer lifetime	9 years
Cost of OHP Foundation	Same as OSS foundation

The resulting key outputs for the three representative locations and two project sizes are provided in Table 25 below. As discussed previously, the wind intermittency results in a capacity factor of 30 to 45%. This reduces the power available for hydrogen generation to about 40% of installed nameplate capacity. Further, the average wind speed is location dependent, resulting in varied output for the three different locations.

Table 25: H2 Results

H2 Generation and Other Key Results						
	Location A		Location B		Location C	
	105 MW	435 MW	105 MW	435 MW	105 MW	435 MW
Electrolyzer Size	40 MW	180 MW	40 MW	180 MW	40 MW	180 MW
H2 Production (tons/year)	7,029	30,297	6,527	28,135	6,141	26,470
Water Consumption (m^3/year)	75,832	326,883	70,420	303,558	66,257	285,595
Annual* energy consumption (MWh/year)	351,898	1,516,892	326,785	1,408,651	307,465	1,325,295
*Dedicated to H2 production only						

3. OPEX

The operational cost of the hydrogen generation system can be categorized into three main components: the expenses associated with fresh water supply and desalination, compression OPEX, and the cost of replacing an electrolyzer unit. To ensure that the electrolyzer units are producing at the same level of output throughout the lifespan of the project, the cost of replacing an electrolyzer unit (Table 26) is added to the annual costs. Based on the AquaTerra study mentioned in III.D.2.a), an operational lifespan of 65,000 hours for an electrolyzer is assumed, with a replacement cost of $400,000 per megawatt (MW). In the cases, a project life span of 20 years has been considered, a yearly up time for an electrolyzer unit of ~8400 hours per year gives the following cost of maintaining the electrolyzer unit.

Table 26: Electrolyzer Replacement Costs

Electrolyzer Replacement Costs (Non-Location Dependent / Non-Repurposed) (M$/year)	
105 MW (40 MW H2 Production)	435 MW (180 MW H2 Production)
M$2.1	M$9.3

Table 18 provides valuable information on the operating cost of the desalination unit, i.e., the cost of obtaining fresh water. Utilizing the specifications listed in Table 24, OPEX associated with the desalination unit is then calculated.

Finally, a simple formula for compression OPEX, estimated as 2% of the compressor Capex is used. The O&M Strategies and Factors discussed in Section III.C.7.b) for the power generation system are considered here as well to account for different maintenance conditions.

4. Compression Needs Analysis

The study initially assumed that the hydrogen produced offshore would need to be compressed to higher pressures in order to bring it to shore. To check this, PIPESIM modeling software generated shore delivery pressure ranges for different hydrogen flow volumes, distances to shore and pipeline diameters.

Based on electrolyzer specs, an assumption is made that hydrogen (H_2) exits the electrolyzer compressed at 30 bara (455.7 psig) and an output temperature of 50 degC (122 degF). For the base case, an assumption is made that a 14-inch outer diameter (OD) (13.2496-inch inner diameter (ID)) pipeline will be used.

The subsea temperature of the Gulf of Mexico ranges from 78 degrees Fahrenheit (degF) at the surface of the water to approximately 40 degF at the sea floor at around 5,000 feet (ft) (Forrest, 2007). Since the deepest bathymetry where the platforms are located does not exceed approximately 3,000 ft (Figure 15) A seabed temperature of approximately 45 degF is assumed.

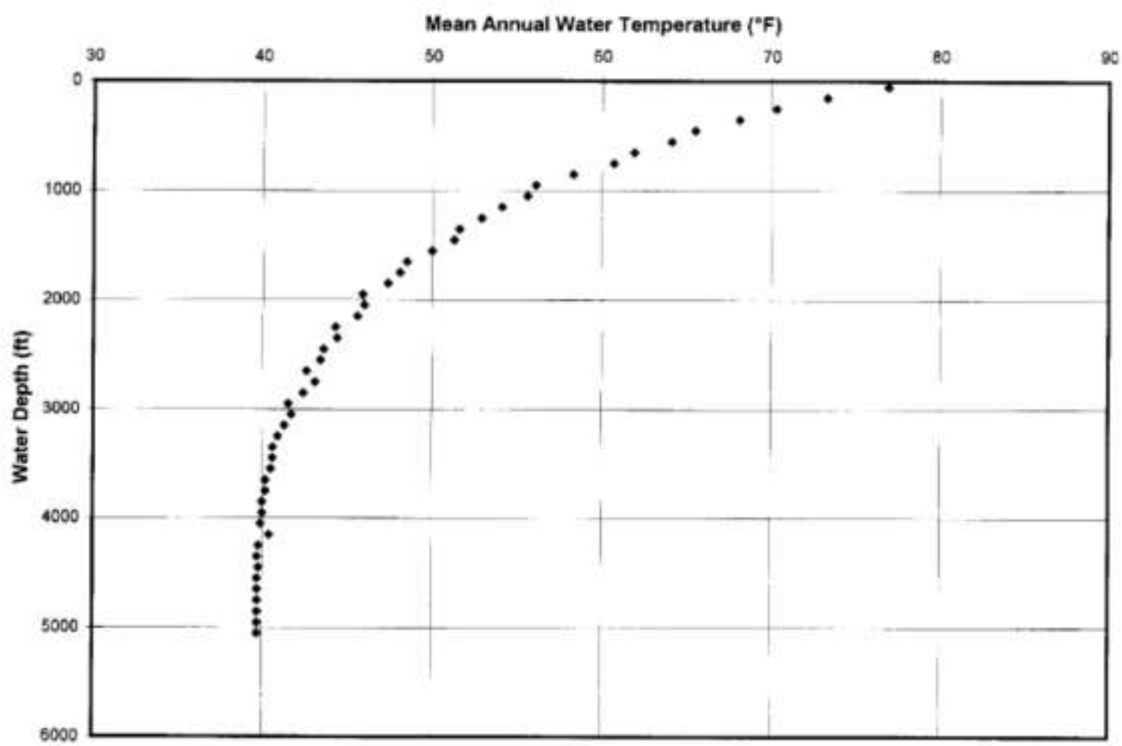


Figure 15: Mean annual water temperature vs. depth averaged for 100-foot intervals of depth in the Northern Gulf of Mexico. Data from the NOAA World Ocean Database. Adapted from (Forrest, 2007)

The geospatial dataset is examined to estimate the range of distances over which the hydrogen will need to be transported to reach shore. For simplicity, for the screening level study in Phase 1, an assumption is made that this would be the distance from the offshore location to the nearest onshore grid connection point. The furthest distance was 250 miles, the closest was in the range of 5 miles. These two distances were used in the PIPESIM modeling. For completeness, one intermediate distance of 125 miles was added. A range of flowrates for the ~100 MW project (300 kg H_2/hr), ~500 MW project (2500 kg H_2/hr) and one in-between (1400 kg H_2/hr) was used.

Shore delivery pressures was then generated for the 14" pipeline for the 3 flow rates by 3 distances matrix, as well as the shore delivery temperatures (Table 27). The PIPESIM simulation results demonstrated the sufficiency of an inlet pressure of 30 bar (450 psi) to bring H_2 to shore for up to 2500 kg H_2/hr and 250 miles.

Table 27: Shore Delivery Pressure and Temperature for Various Flowrates and Distances

	5 miles		125 miles		250 miles	
Flowrate (kg/h)	**Shore Delivery Pressure (psia)**	**Temperature Out (degF)**	**Shore Delivery Pressure (psia)**	**Temperature Out (degF)**	**Shore Delivery Pressure (psia)**	**Temperature Out (degF)**
2,500	434.4	73.3	418.5	45.0	401.3	45.0
1,400	434.9	57.9	429.7	45.0	424.2	45.0
300	435.1	45.0	435.0	45.0	433.8	45.0

With these simulations, the conclusion is that because of the low volumes and a large pipeline diameter, onshore arrival pressure is not very sensitive to distance and more sensitive to volume. Therefore, a new set of PIPESIM cases with a fixed distance at a midrange of 150 miles was run. Flowrates from 500 to 4,000 kg/hr with increments of 500 kg/hr was used. Table 28 displays the results.

Table 28: Flowrate vs. Shore Delivery Pressure for 14-inch Hydrogen Pipeline

Flowrate (kg H_2/hr)	**Shore Delivery Pressure (psia)**
4000	384.2
3500	396.2
3000	406.5
2500	415.1
2000	422.2
1500	427.7
1000	431.7
500	434.3

Based on these results the conclusion is that offshore compression was not required. Instead, onshore compressor to compress the hydrogen up to the trunk line pressure (~750 to 1500 psia) can be used. Utilizing onshore compression has multiple advantages – reduced equipment and installation and maintenance costs, reduction in space and load on the offshore structure, and most importantly, a reduced operating pressure in the pipeline which mitigates losses, and structural integrity risks.

E. Decommissioning and Repurposing Assumptions

At the end of their oil and gas production life, all offshore structures have to be, per regulation, decommissioned. This includes plugging and abandonment of all wells, removal or safe preservation in-place of all pipelines, safe decommissioning and removal of oil and gas equipment (topsides), and disposal of any floating or fixed structures (jackets or platforms). The topsides and jackets are usually brought back to shore and disposed of, but on occasion, jackets are dismantled in place and allowed to sink to the seafloor (rigs to reef program).

Initially the costs of such decommissioning were included in the capex estimates for ROICE projects. Further, an initial assumption was made that it would be more cost effective to just remove some of the existing topside equipment – just enough to accommodate the power gen or hydrogen gen equipment – and leave all the rest of the equipment in place for future decommissioning. These assumptions changed during the course of the study after discussions with decommissioning experts on the SPC. It became clear that it was more cost effective to remove all of the oil & gas topsides, assemble a new, compact topsides onshore for the clean energy project and install that on the existing jacket/structure. This would imply that all wells and topsides would have to be decommissioned as per the normal end-of-life practice with costs borne by the current operator. Only the jacket and deck would be left standing to be utilized by the ROICE project. Except for pipelines that would be used to bring the hydrogen to shore, all pipelines would also be decommissioned. All the costs for such decommissioning are now assumed to be borne by the current operator.

All the same, the results of the brief research into decommissioning is provided. The Bureau of Safety and Environmental Enforcement (BSEE) provides Gulf of Mexico (GOM) decommissioning cost estimates with P50, P70, and P90 distributions based on operators' expenditure data ((Bureau of Safety and Environment Enforcement (BSEE) Data Center, 2023) and (Byrd, 2016)). These data were analyzed to understand the different components of decommissioning costs and the range of variability. Table 29, Table 30, and Table 31 illustrate the mean, standard deviation (std), the minimum (min), maximum (max), and the 25%, 50%, and 75% values for pipelines, wells, and platforms respectively. The three percentage values refer to the costs where the indicated percentages of the data population fall below these costs.

Table 29: Cost Distribution for Pipelines

mean	$583,087.16
Std	$538,322.02
Min	$1.00
25%	$268,532.75
50%	$383,752.00
75%	$700,893.62
max	$5,258,139.00

Table 30: Cost Distribution for Wells

mean	$6,649,115.52
std	$10,828,886.01
min	$18,765.00
25%	$419,059.49
50%	$708,302.33
75%	$13,490,982.40
max	$38,597,684.00

Table 31: Cost Distribution for Platforms

mean	$2,050,423.78
std	$1,648,309.40
min	$159,575.00
25%	$782,963.62
50%	$1,612,038.50
75%	$2,963,161.62
max	$16,286,017.00

For repurposing cases, the existing jacket structure is assumed to take the place of the Offshore Substation (OSS) foundation, and the new ROICE project topsides are built onshore and installed on the existing jacket. This eliminates foundation costs from ROICE Capex. The installation costs for the topsides components remain the same as in a new build case, considering the cost of vessels and crews to install the topsides.

For new build cases, additional capex includes jacket procurement and installation costs as well as new pipeline costs.

These assumptions enable an accurate analysis of the cost benefits and financial implications of repurposing compared to constructing a new ROICE project.

F. Iterative Geospatial Algorithm

With all of the above inputs, the ROICE LC Model can generate LC values for a power export or hydrogen export project situated at any point in the Gulf of Mexico. The Iterative Geospatial Algorithm was then developed to efficiently calculate LC values across the entire GOM and generate "heat maps". A hexagonal grid across the GOM developed by Xodus for a previous project was used to estimate LC values. Python coded scripts were developed to enter the input values, execute the ROICE LC Model and gather the results for more than 64,500 polygons covering the US GOM. The scripts ingest the Xodus provided shapefile containing data for these polygons, specifically hexagons, including the mean wind speed, mean bathymetry, and mean wave height as well as the export distance, installation port distance, and O&M port distance. The scripts programmatically map, extract, and input these values from the shapefile for each hexagon into the Excel workbook's relevant sheets. The scripts select the required options such as whether to compute levelized costs for electricity or hydrogen, model the repurpose or new build scenario etc. Excel calculates the results such as LCOE and LCOH, and the scripts aggregate them along with the units and provide comma separated values (csv) files for mapping in ArcGIS.

The scripts determine the latitude and longitude based on the World Geodetic System 1984 (WGS 84) coordinate system for each of the hexagons' centroid and add these computations into the csv file. The scripts also load the csv files. provide data tables and map out values in an interactive OpenStreetMap for a quick visual validation of the correctness of the input data, script computation, and locations of the polygons' centroid points (Figure 16). In addition, the scripts extract the first LCOE and LCOH below -400 meters bathymetric depth as an indicator of cost cutoffs for deep versus shallow water.

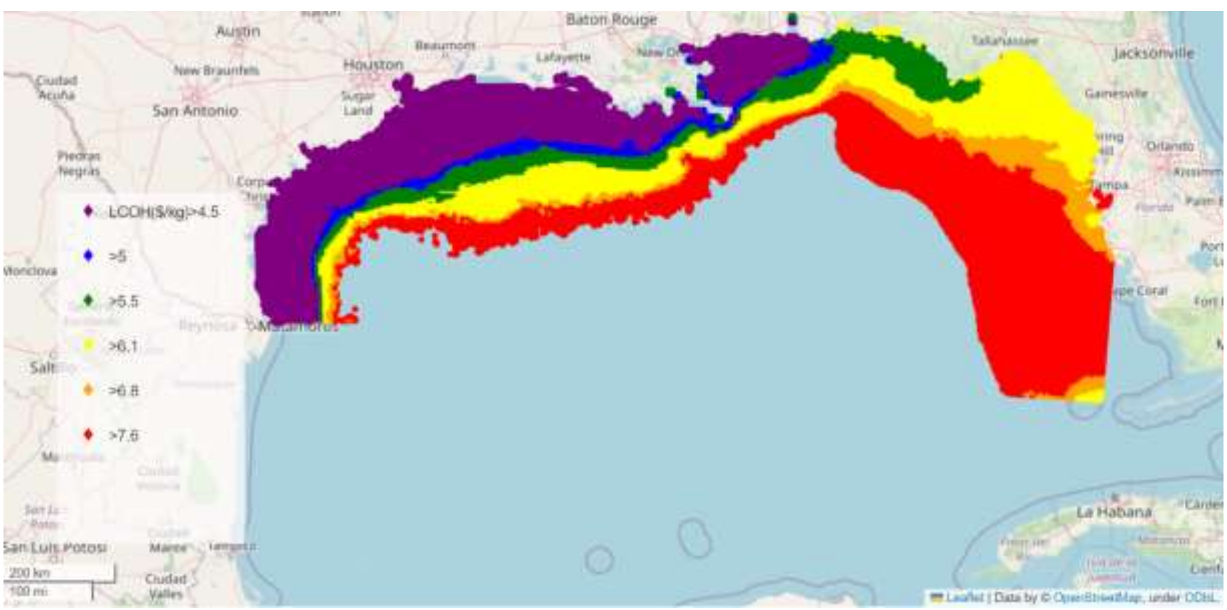


Figure 16: Visual Validation of LCOH Values

In total, eight scripts are executed to provide the repurposed and new build LCOE and LCOH for 105 and 435 MW cases for each of the more than 64,500 points. Additional geospatial data provided include annual energy output, annual hydrogen production, energy dedicated to hydrogen production, total capital expenditures (CAPEX) and total operating expenditures (OPEX).

G. Geospatial Inputs and Methodology

1. Wind and Bathymetry Base Maps

As discussed in Section II, the Gulf of Mexico region has a vast offshore wind energy potential due to its favorable wind resources and proximity to coastal areas with high electricity demand. Wind power along the Gulf of Mexico for hydrogen generation offers a sustainable pathway to decarbonize the region's energy sector, reduce greenhouse gas emissions, and foster economic growth. The average wind speed ranges in the US GOM ranges from 6.9 to 8.6 m/s (Figure 17) with the best wind speeds occurring at the southern coastal part near the Corpus Christi region. The other significant advantage of the US GOM is the relatively shallow water depths (Figure 18). The shallow water, near shore areas along the Gulf Coast contains significant oil & gas infrastructure that can be repurposed for clean energy. For purposes of this study, only areas with water depths under 1000 meters was considered, since floating wind solutions for deeper waters are not currently available. Besides, these locations are unlikely to prove profitable.

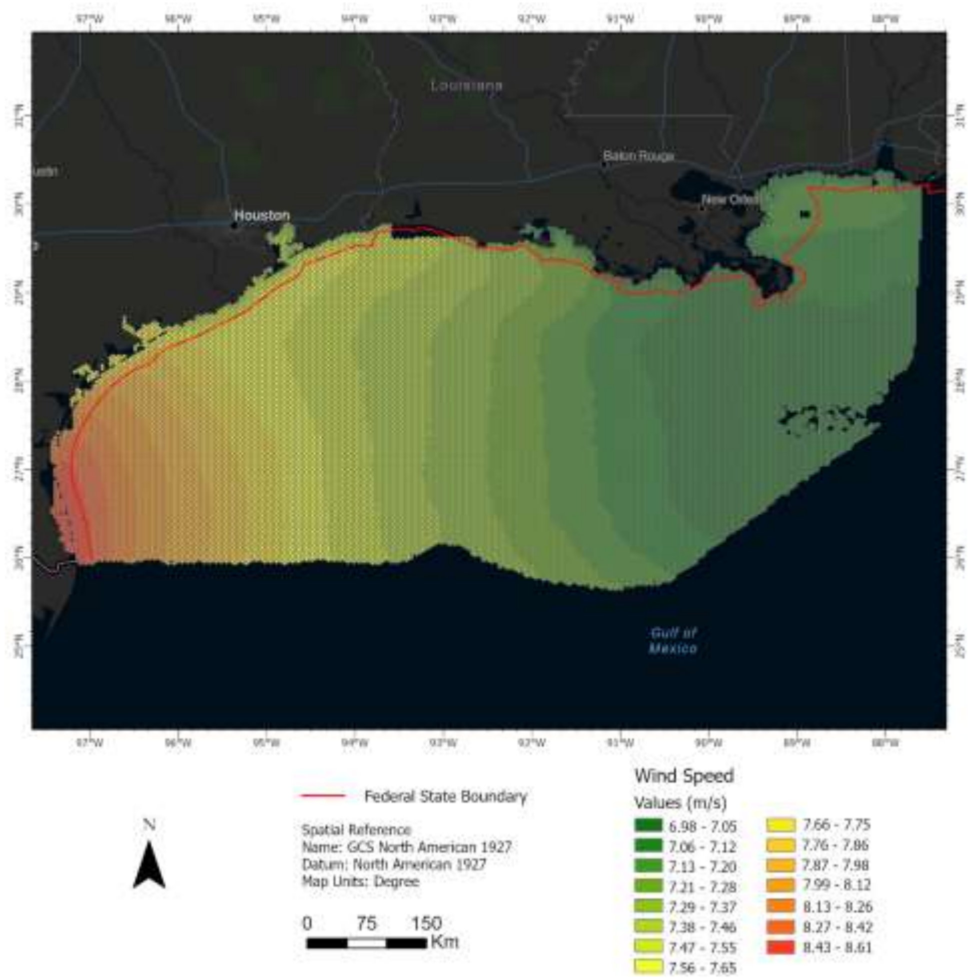


Figure 17: Average Wind Speed along the Gulf of Mexico

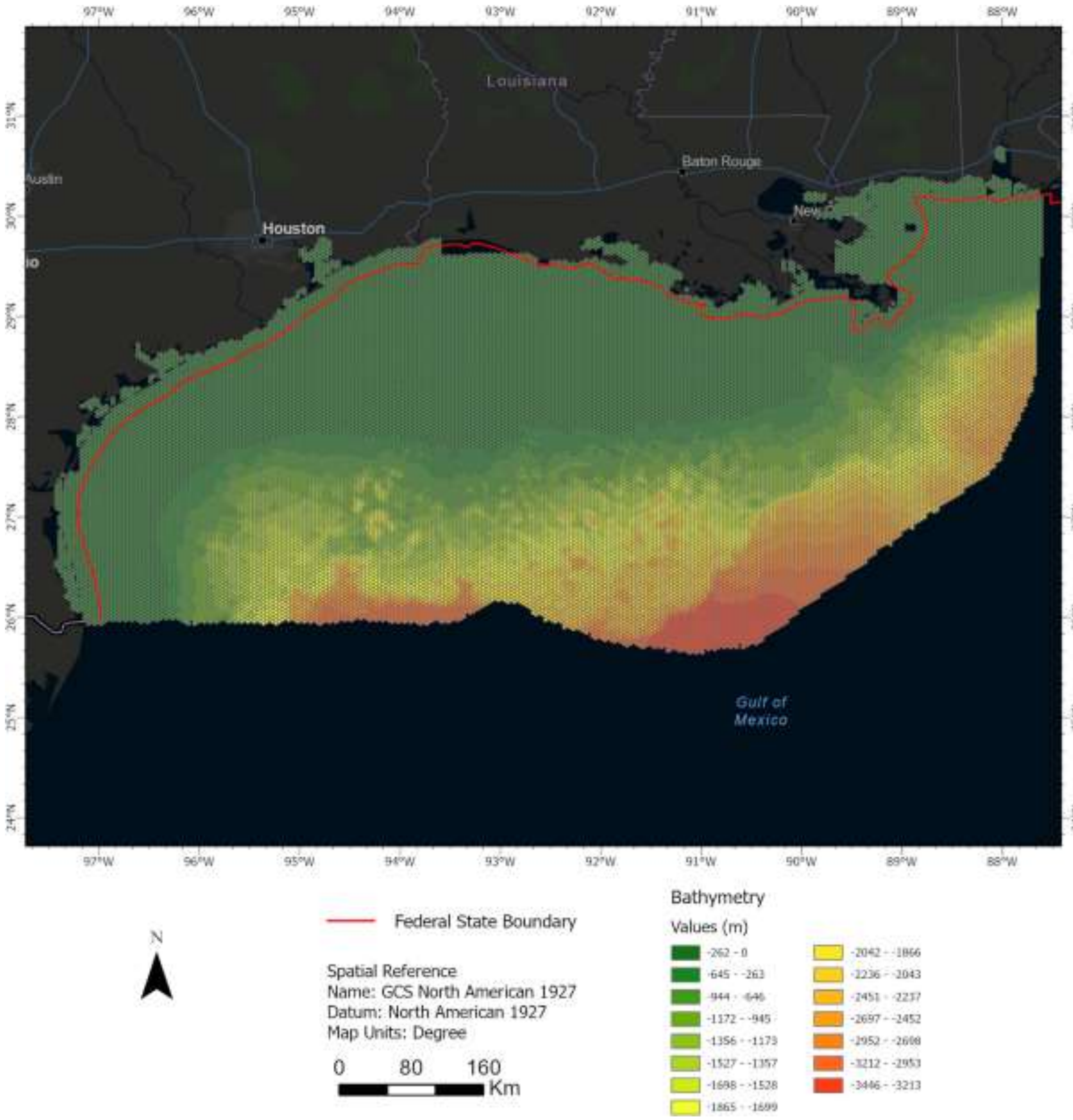


Figure 18: Bathymetry variations along the Gulf of Mexico

These geospatial inputs are crucial for identifying suitable locations for offshore wind farms and helping to determine areas with optimal wind resources and favorable conditions for wind turbine installation. Accurate bathymetry helps in optimizing cable routes, reducing costs, and minimizing potential environmental impacts as well. It should also be noted that the federal jurisdiction for offshore waters starts at nine US nautical miles for Texas and Florida coast and three US nautical miles for Louisiana and three international nautical miles for the other coastal states. This boundary is shown in many of the maps provided in this report.

2. Installation and O&M ports

The provided map (Figure 19) illustrates the proximity of each location to the nearest installation and O&M ports. It's important to note that not all ports possess the necessary infrastructure to accommodate wind turbine installations or provide the facilities required to house crews and equipment for O&M activities. The map therefore only includes those ports that are able to support these activities. These GIS inputs play a pivotal role in determining essential cost elements. For instance, these inputs contribute to the calculation of the O&M service factor [III.C.7.b)] and installation time and vessel travel times [III.C.6.b)].

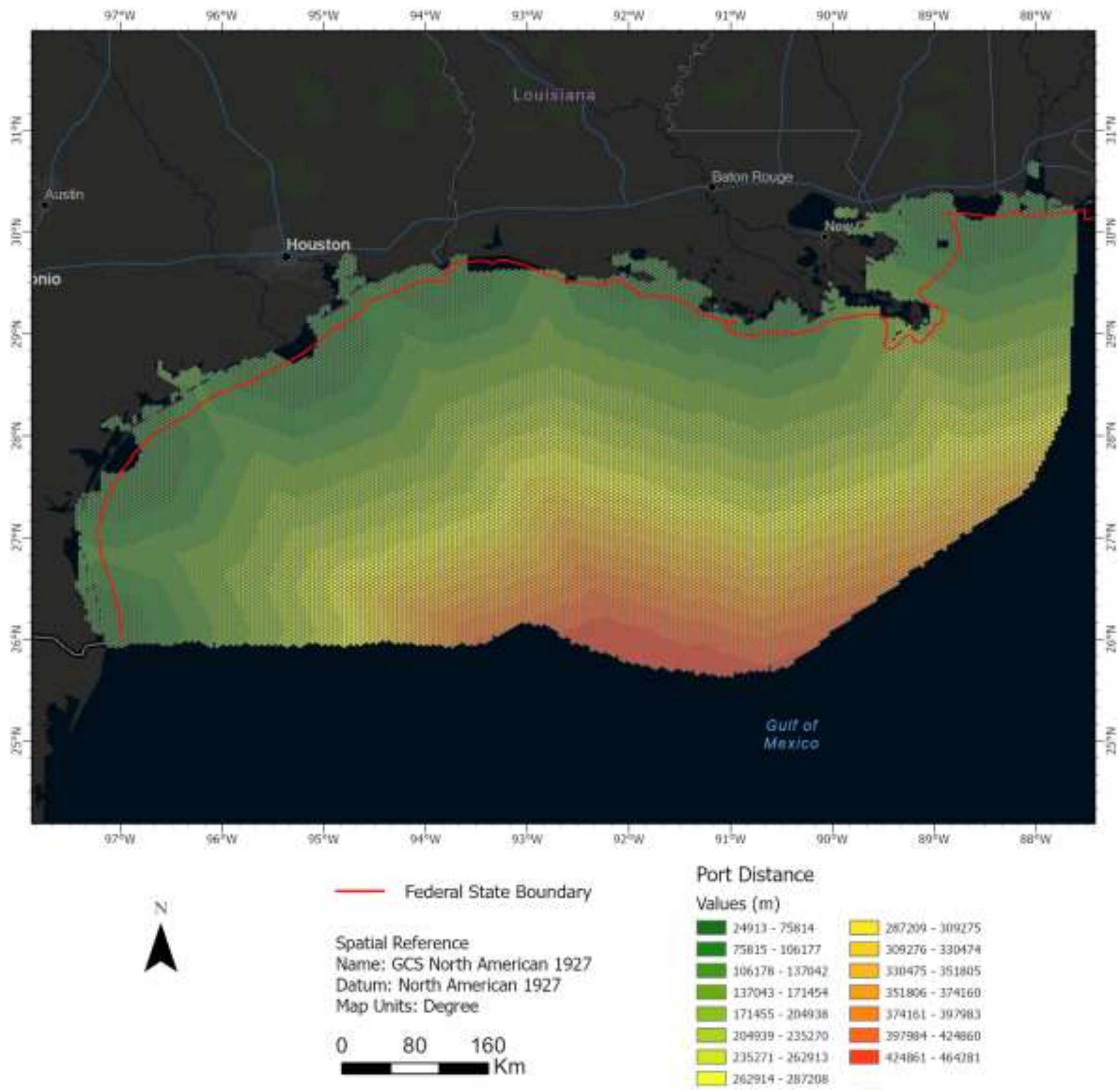


Figure 19: Installation and O&M Ports Proximity

3. H2 Hexagonal Gridding

Geographic Information System (GIS) is a computer-based system that examines and reveals geographically referenced data (Acevedo-Garcia et al., 2008). GIS assists in the analysis of conventional quantitative and qualitative information, laying those facts in a geographic context, and enabling deeper inferences regarding that information (Archbald et al., 2018). A GIS tool (ArcGIS pro) was used to integrate multiple datasets and the tessellation method was used to evaluate the whole study region. The tessellation method was utilized to create an H3 hexagon grid of recurring shapes over the area of interest. H3 is a hierarchical indexing system, which was created by Uber (Sahr, 2011; Zeidan & Rempel, 2023). (add reference) to cover the Earth's surface. A hierarchical indexing grid suggests that every hexagon can be subdivided into sub-unit hexagons. There are numerous advantages to using hexagonal grids for aggregation and summarization rather than to use administrative boundaries such as states, counties, or block groups. H3 hexagons are excellent because they are made over a model of the Earth, suggesting their position remains constant at every resolution. Therefore, H3 hexagons are used as standardized grid techniques across the study region because of its balanced compromise and uniformity in size. The tessellation tool in ArcGIS pro (software) has been utilized to generate the H3 hexagons. H3 hexagon contains a total of sixteen resolution levels, ranging from 0 (coarsest) to a higher number (finer) and each resolution level subdivides the study area into smaller hexagons. In the study area, the resolution level of 4 and the diameter of 2.8 miles for each hexagon were used to get the significant and promising patterns. Furthermore, the statistical mean of all available input data points within each hexagon was calculated by using the geoprocessing tool in GIS to display the final outcomes across the study region.

4. Case Nomenclature

The ROICE LC Model and the Iterative Geospatial Algorithm were used to generate LC values and LC "Heat Maps" across the US GOM for a set of eight ROICE cases. These are listed below in Table 32.

Table 32: Case Nomenclature

Product	Capacity	Repurposing	New Build
Power	435 MW	E500R	E500N
	105 MW	E100R	E100N
Hydrogen	435 MW (180 MW Electrolyzer Capacity)	H500R	H500N
	105 MW (40 MW Electrolyzer Capacity)	H100R	H100N

The case nomenclature follows a simple set of rules: E for "Electricity" or power export projects, H for Hydrogen export projects; R for repurposing projects, N for New Build Projects; 500 to represent a commercial scale project (actual project capacity modeled is 435 MW) and 100 to represent a demonstration scale project (actual project capacity modeled is 105 MW). Thus, E500N is a new build commercial scale power export project; H100R is a repurposed demonstration scale hydrogen export project. As discussed before, the hydrogen export projects assume that all of the power generated from the turbines are used to generate hydrogen. The equivalent electrolyzer size is shown above.

5. LC Estimation for Assets

The LC heat maps were used to assign LC values to each of the almost 1700 assets in the GOM. The "add spatial joining" method was used for this. Spatial joining is a prevailing practice used in the Geographic Information System (GIS) that allows combining information from two or more spatial datasets to get new insights and determine how properties from the datasets should be matched. In the study, this technique was used to assign attributes obtained from the ROICE LC model output and assigned to the hexagonal grid system (join layer) to the location of the oil and gas platforms (target) within a distance of no greater than 1.7km. In Phase-2, improvements to this technique will be evaluated to achieve greater accuracy.

Once LC values and other data were assigned in this manner to each asset location in the GOM, these assets were able to be ranked to identify the most favorable locations for ROICE projects. This was used to shortlist assets for which detailed site-specific ROICE design will be developed in Phase 2. For a select group on non-favorable assets, it will also enable investigation during Phase 2 of what would make a ROICE project profitable on these assets.

IV. Results and Discussion

A. LC Heat Maps for the US GOM

Levelized Cost of Energy (LCOE, \$/MWh) and Levelized Cost of Hydrogen (LCOH, \$/kg of H2) heat maps provide a convenient visual representation of the relative cost of implementing a power or hydrogen export project across a wide geospatial area. These maps are very significant for policymakers, energy planners, and investors to assess the economic viability of different energy technologies and make informed decisions about energy infrastructure development. These heat maps for Power Export and Hydrogen Export cases will now be presented and analyzed.

1. Power Export Cases (LCOE, \$/MWh)

The LCOE heat map for E500R (Power Export, 435 MW Size, Repurposed) is shown in Figure 20. The levelized cost ranges from 81.97 to \$168.23/ Megawatt-hour (MWh). The LCOE heat map for E100R (Power Export, 105 MW, Repurposed) is shown in Figure 21. LC's range from 86 to \$ 231/MWh for this case. As expected, economies of scale help keep the costs down for the larger project, especially at the higher end. In both these cases, as can be seen from the color shading in these heat maps, locations closer to shore in shallow waters have lower costs. The lower end of the LCOE ranges above thus correspond to near-shore shallow water locations while the higher end are locations are farther from shore in deeper water. This is primarily driven by the higher costs for floating turbines and longer cable lengths to bring the power to shore. A secondary contributor is higher installation and maintenance costs for locations further from shore and in deeper water, requiring more complex service vessels.

The LCOE heat maps for new build cases can be seen in Figure 22 and Figure 23 for the E500N case (Power Export, 435 MW Size, New Build) and the E100N case (Power Export, 105 MW Size, New Build). LC for the E500N case ranges from 82.06 to \$220.26/MWh as shown in Figure 22 , while those for E100N case ranges from 86.14 to \$436.78/MWh as shown in Figure 23. As can be seen from a comparison of these LC ranges, repurposing provides a greater LC reduction at the higher end of the range (deeper waters and/or further from shore). This is primarily driven by the cost of the OSS foundation jacket which becomes more expensive as the water depth increases. Repurposing also has a greater impact on the levelized costs for smaller projects, since the savings from reusing the jacket is a larger fraction of the total cost.

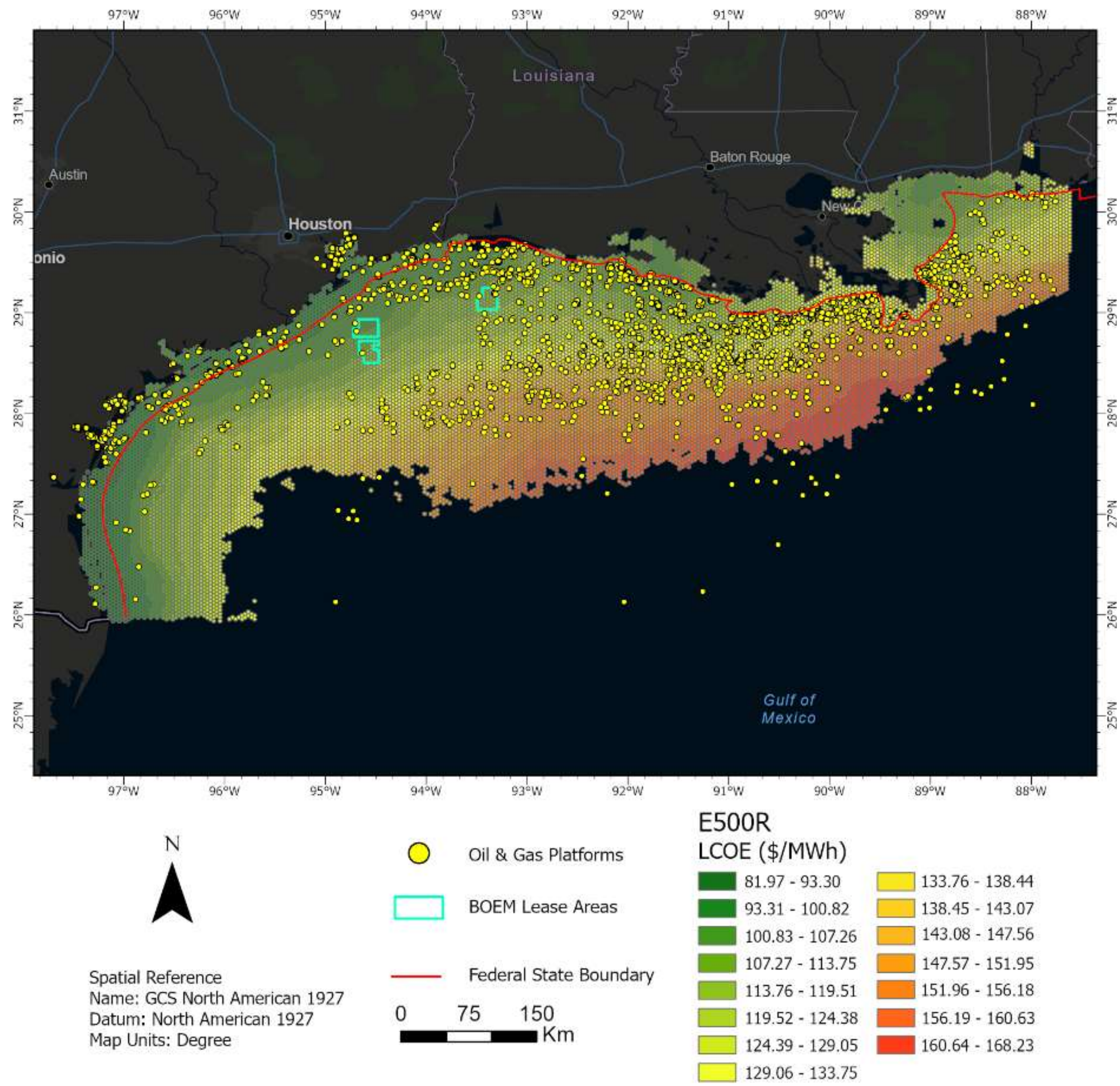


Figure 20: LCOE for power export E500R

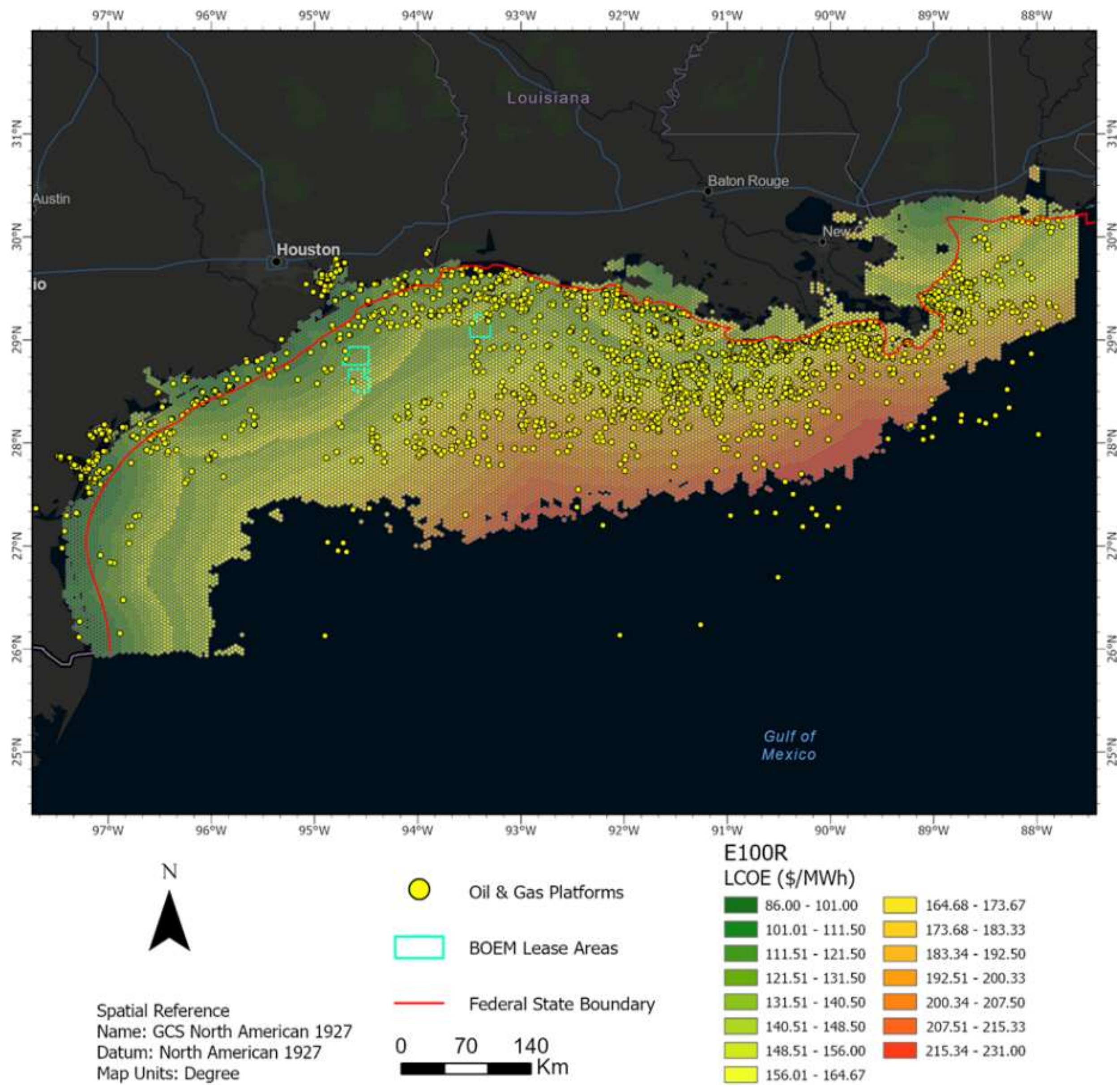


Figure 21: LCOE for power export E100R

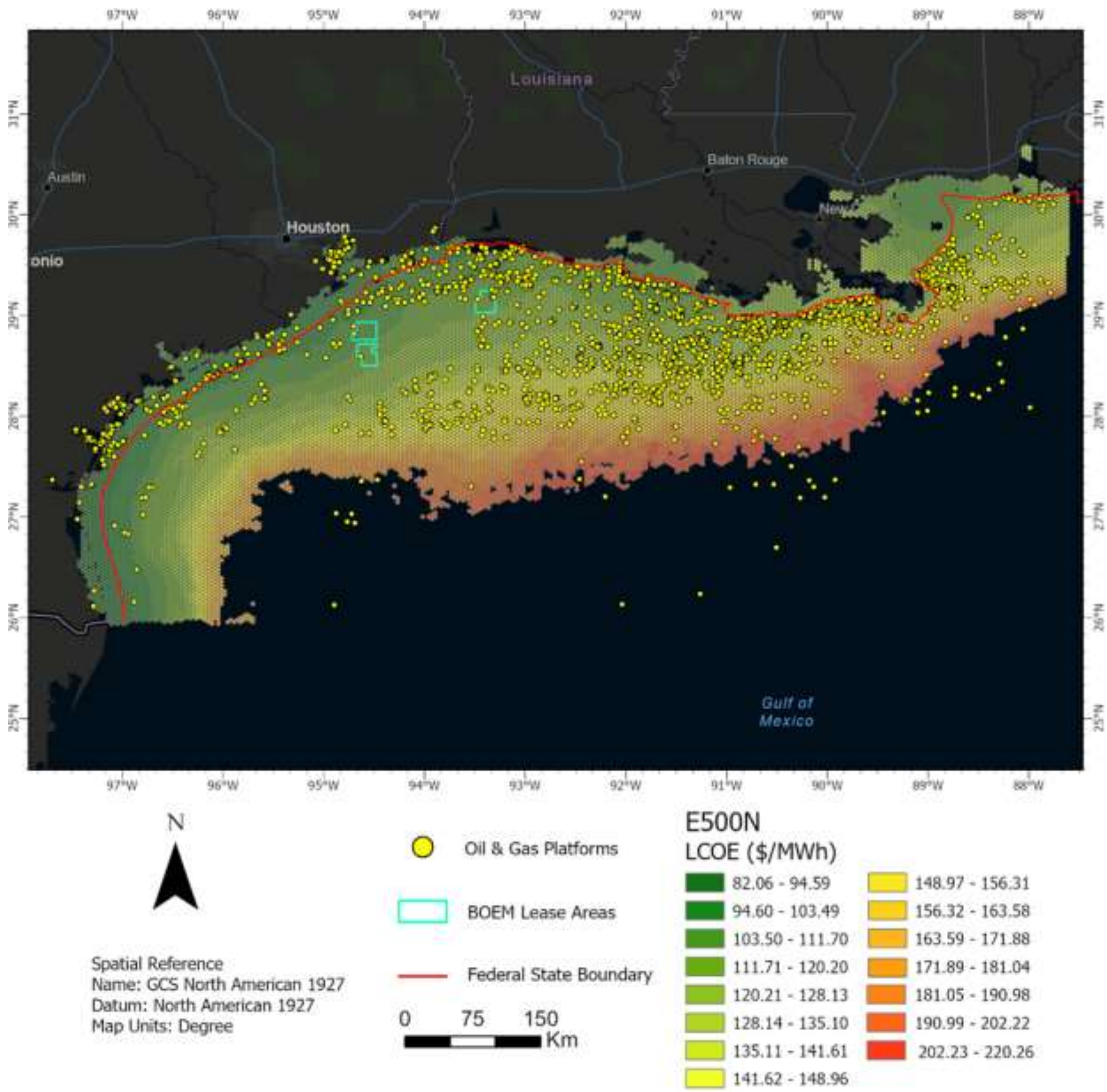


Figure 22: LCOE for power export E500N

In all these maps, the recently announced wind lease areas by BOEM are shown. As can be seen, while not in the lowest cost areas, the LC values in these areas are still quite favorable. Closeness to population centers will also have a positive impact on project economics in this area. A closer look at assets near these areas will be taken in Phase 2 and how such projects can be made economically attractive will be established.

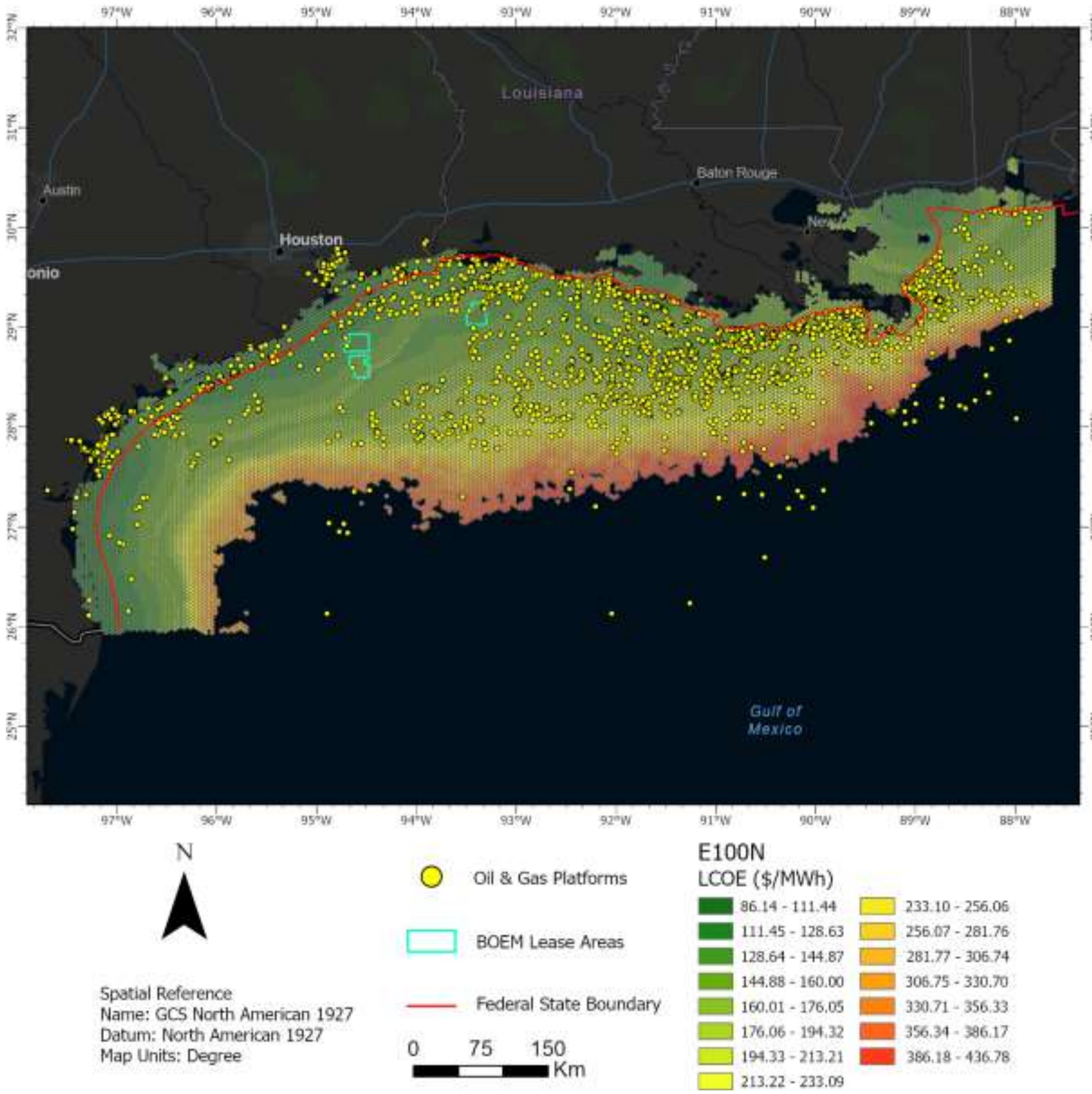


Figure 23: LCOE for power export E100N

Figure 24 compares the LCOE range for the four power export cases in this study to onshore wind and solar photovoltaic (PV) with and without production and investment tax credits (PTC and ITC), with or without storage, and at utility scale or not. The lighter colored bars on the right for each of the project LCOE cases represent cases in water depths greater than 400 m.

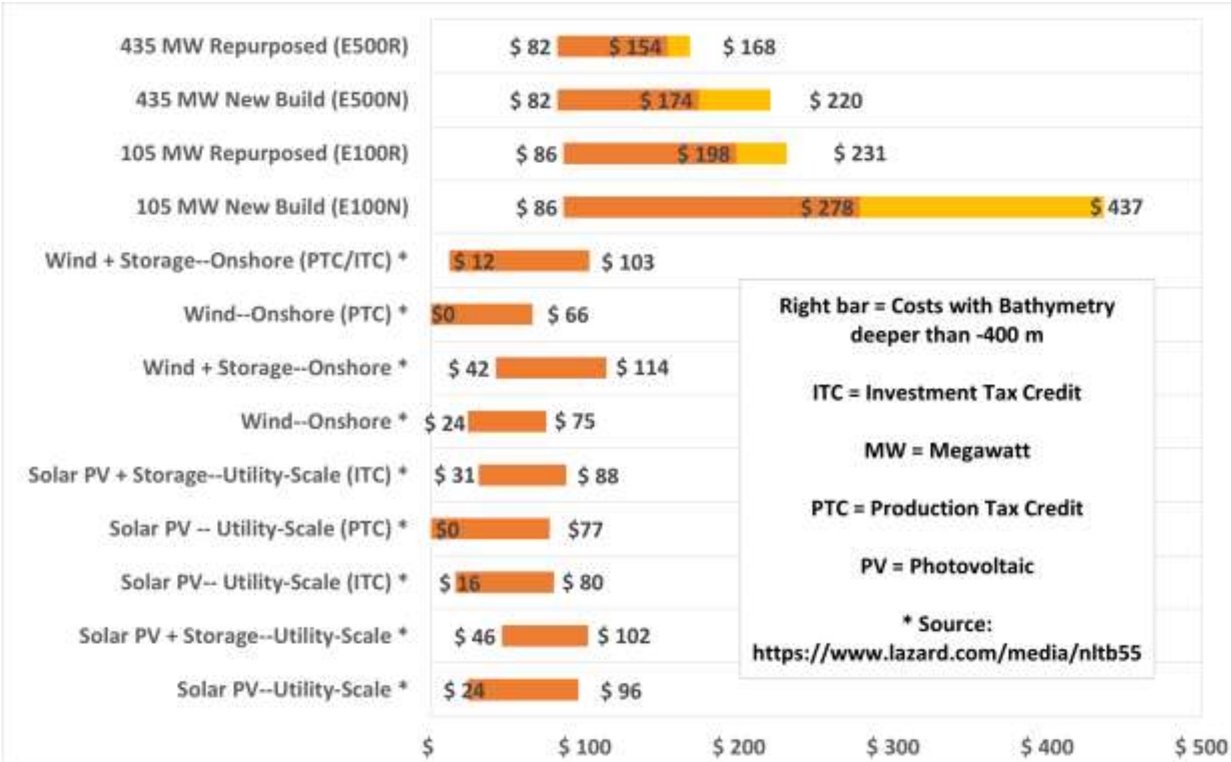


Figure 24: Levelized Cost of Electricity ($/ MWh) (Lazard, 2023)

Figure 25 (a-d) compares all four power export cases from this study on a common scale, enabling comparison and seeing the impact of project scale and comparing new build and repurposing cases.

Key conclusions to draw from this comparison are as follows:

- As expected, the range of LC for offshore renewable projects is higher than onshore renewables.
- Smaller scale projects need to be in shallow water / near-shore locations to be economic
- Repurposing helps reduce the LC for deeper water and/or far-shore locations
- Repurposing has a greater impact on small scale projects
- In several regions where repurposing does have a tangible impact, the overall LC is high even with repurposing, indicating challenging project economics

However, it should be pointed out that these LC's do not account for any federal credits such as ITC or PTC for renewables. It should also be pointed out that these are screening level estimates with generalized assumptions. More definitive conclusions will be expected to be drawn in Phase 2 where ROICE designs will be developed for specific assets with more accurate cost estimates and include all applicable credits to estimate more accurate project economics.

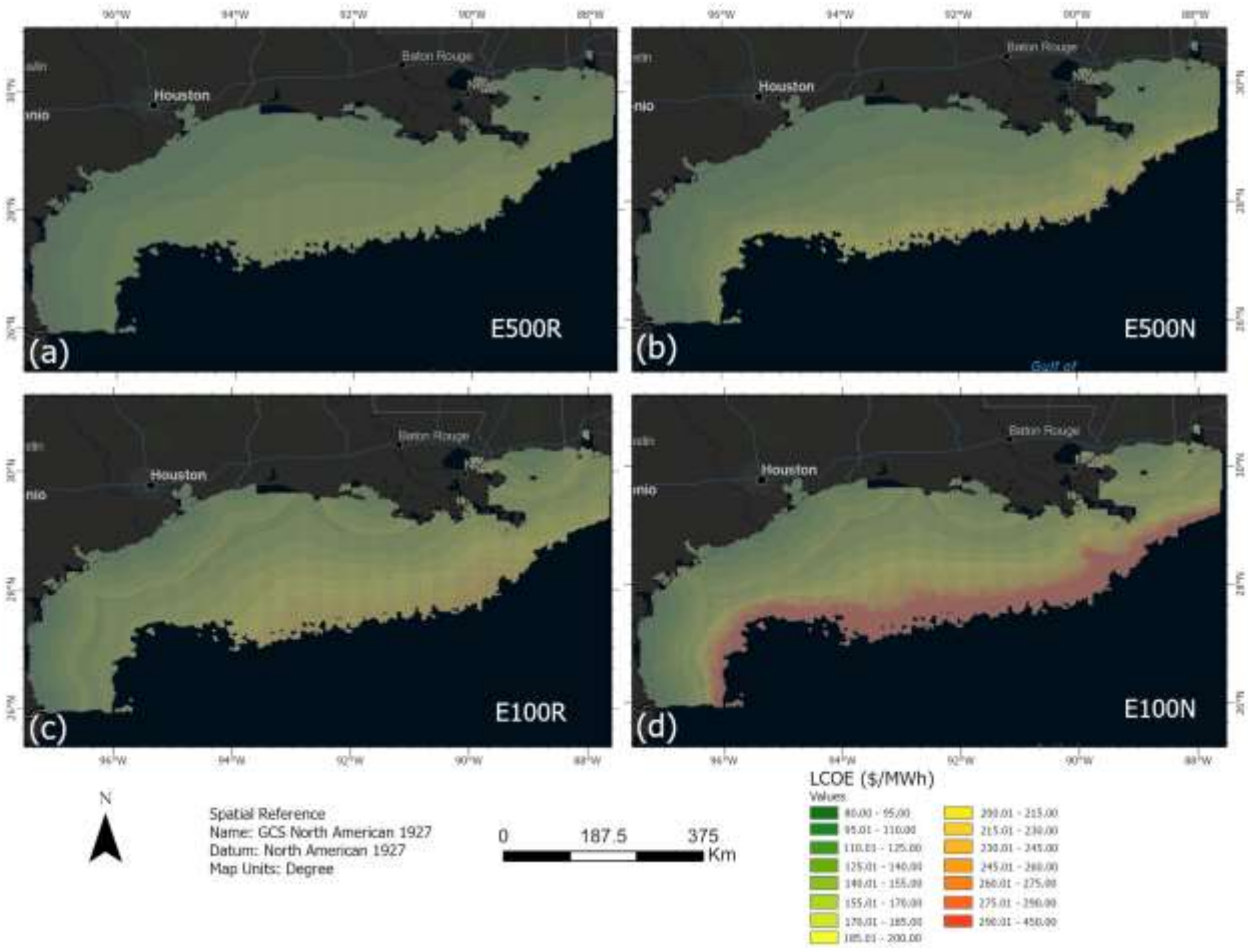


Figure 25: Four Power Export Cases on a common scale (a) E500R (b) E500N (c) E100R (d) E100N

2. Hydrogen Export Cases (LCOH, $/kg)

The Levelized Cost of Hydrogen (LCOH) heat maps allow for comparison of screening level cost of producing hydrogen at various locations in the Gulf of Mexico. As discussed above, these LCOH cases are powered by the appropriate size of wind power generation systems. The "H100" cases thus are supported by a 105 MW wind power generation system for these cases are identical to the equivalent "E100" case, without, of course, the need for export cables. The "H500" cases are supported by 435 MW wind power generation systems identical to those in the equivalent "E500" cases.

The LCOH heat map for the H500R case (Hydrogen export, 435 MW size, Repurposed) is shown in Figure 26 . The LC for this case ranges from 4.76 to $8.21/kg. The equivalent chart for a demonstration scale project H100R (Hydrogen export, 105 MW Size, Repurposed) is shown in Figure 27. LC's for this case range from 4.91 to $8.44/kg. In both these cases, the lower end of the LCOH ranges above correspond to near-shore and shallow water locations while the higher end are locations are further from shore in deeper water. This is primarily driven by the higher cost for floating wind turbines, higher pipeline repurposing costs due to a greater distance from shore. A secondary contributor is higher installation and maintenance costs for locations further from shore and in deeper water, requiring more complex service vessels. However, unlike in the power export cases, hydrogen projects do not have significant economies of scale. The LC for H100R is only 3% higher than that of H500R, across the entire range of LC's. This implies that a large fraction of costs for a hydrogen project scale well with project size. Said another way, in power projects, the cost of export cables does not scale according to the power being exported via these cables. Therefore, higher capacity projects result in lower LC values by sending more power through the same cost of cables. The scale effect is further diluted because hydrogen projects have the option to repurpose pipelines at a cheaper cost than laying new export cables in a repurposed electricity project.

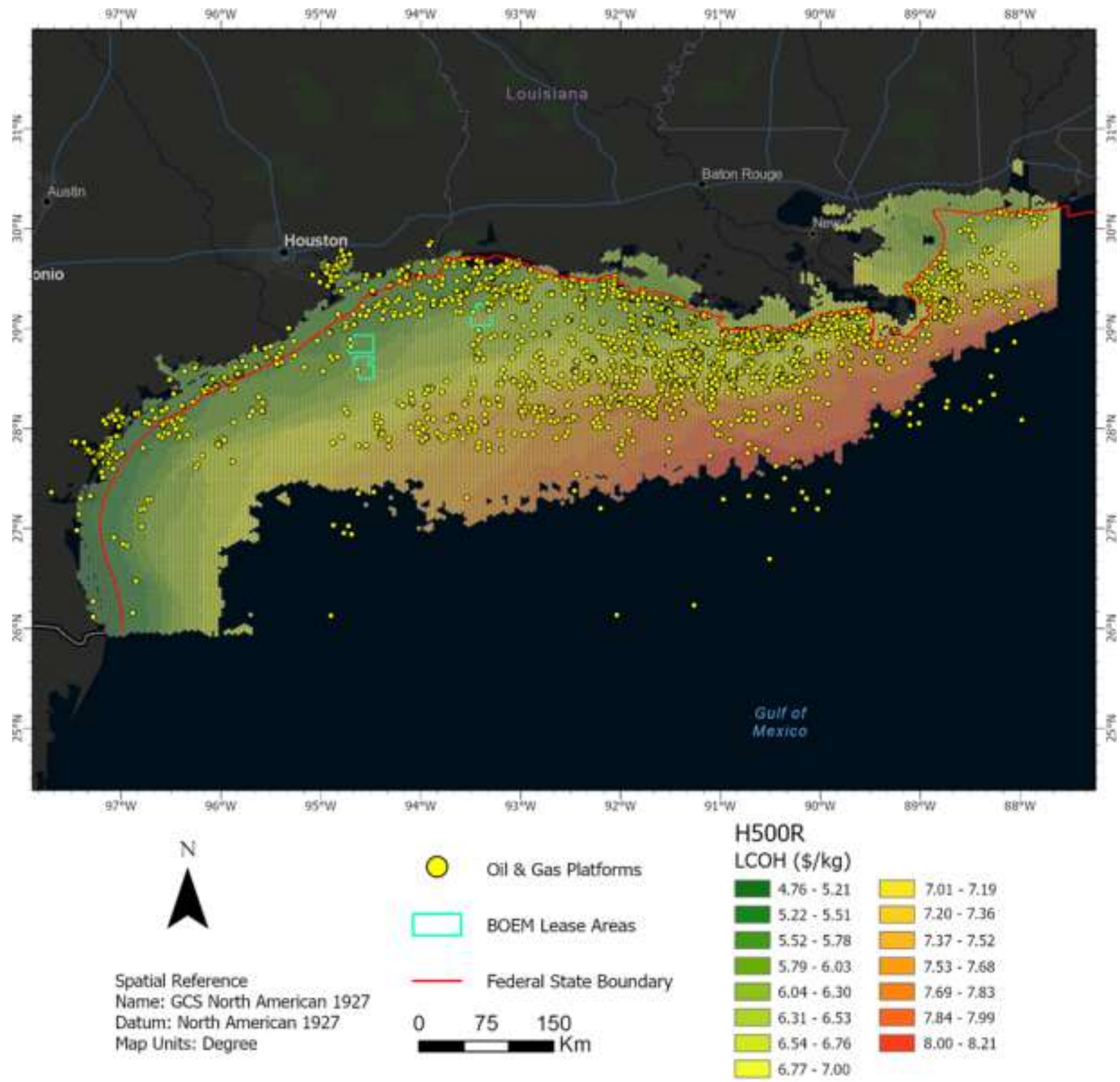


Figure 26: LCOH for power export H500R

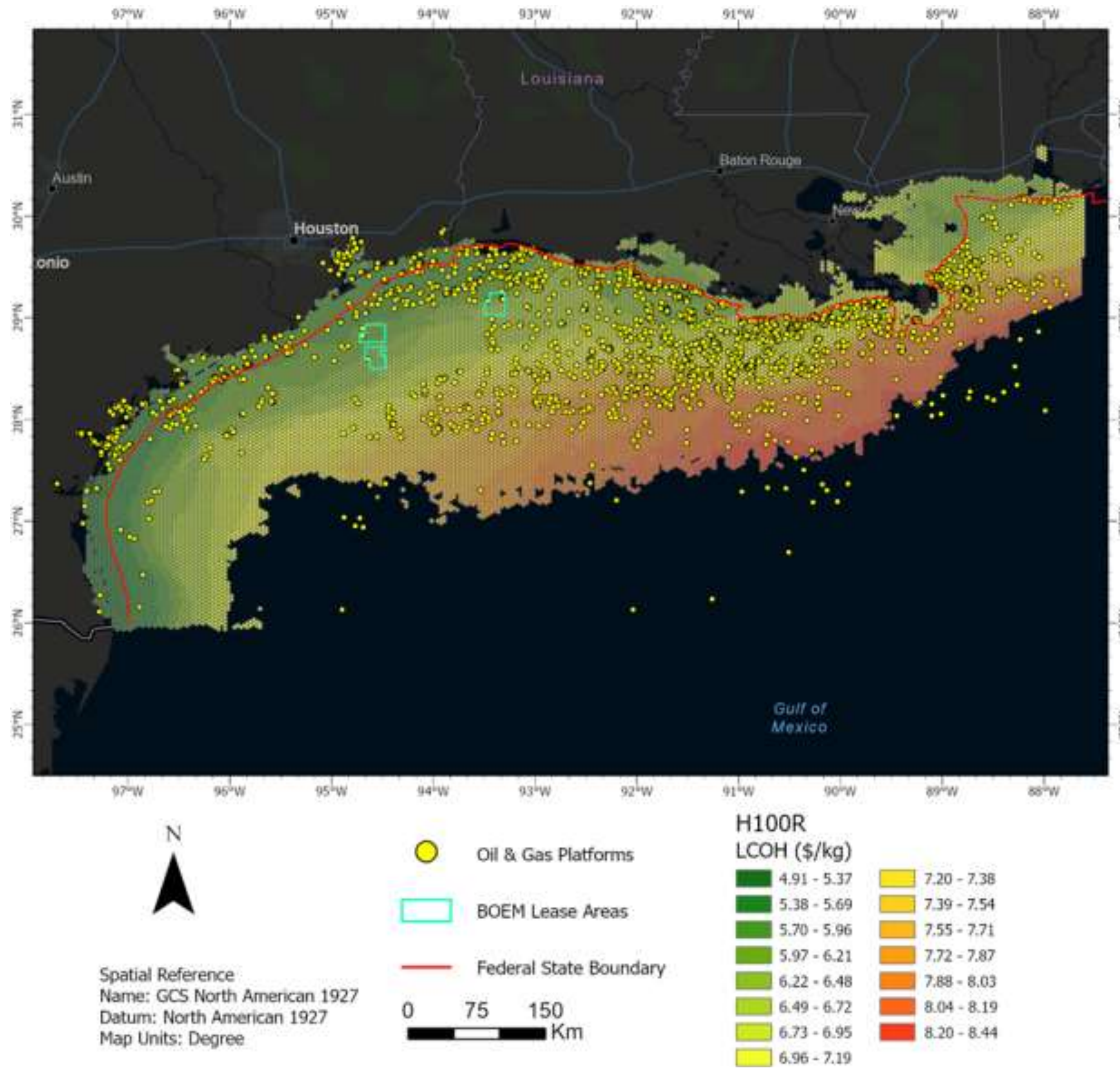


Figure 27: LCOH for power export H100R

The LC heat maps for the equivalent new build cases - H500N (Hydrogen Export, 435 MW size, new build) and H100N (Hydrogen Export, 105 MW size, new build) are shown in Figure 28 and Figure 29. LC's for H500N range from 4.77 to $10.81/kg, while those for H100N range from 4.91 to $19. 64/kg. As in the Power Export cases, repurposing reduces the LC at the higher end of these ranges (deeper water and/or further from shore). Again, this is because new build projects need to install a new foundation and structure to support the hydrogen generation components, the cost of which can be quite significant in deeper waters. Repurposing cases avoid this cost by reusing the existing oil and gas structure.

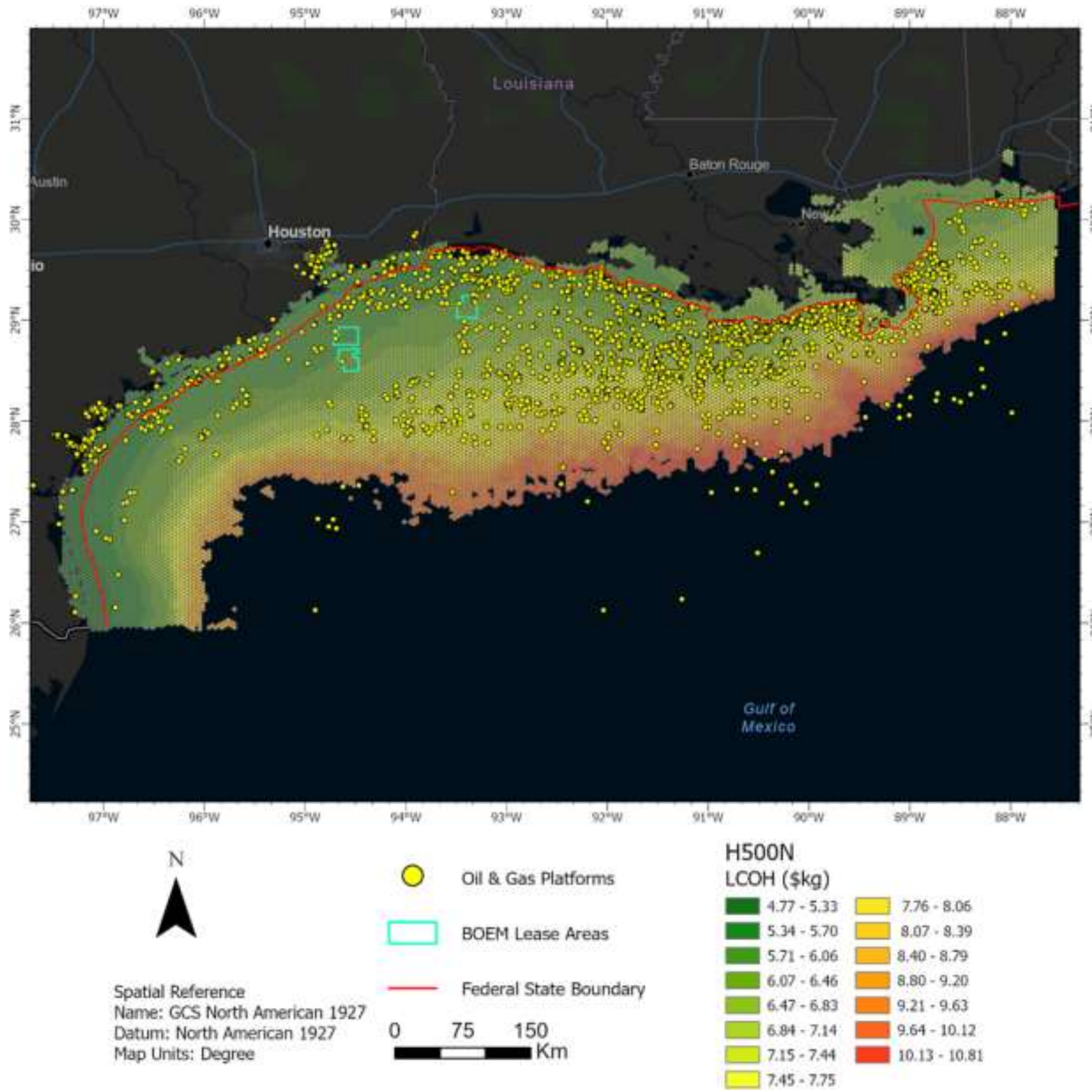


Figure 28: LCOH for power export H500N

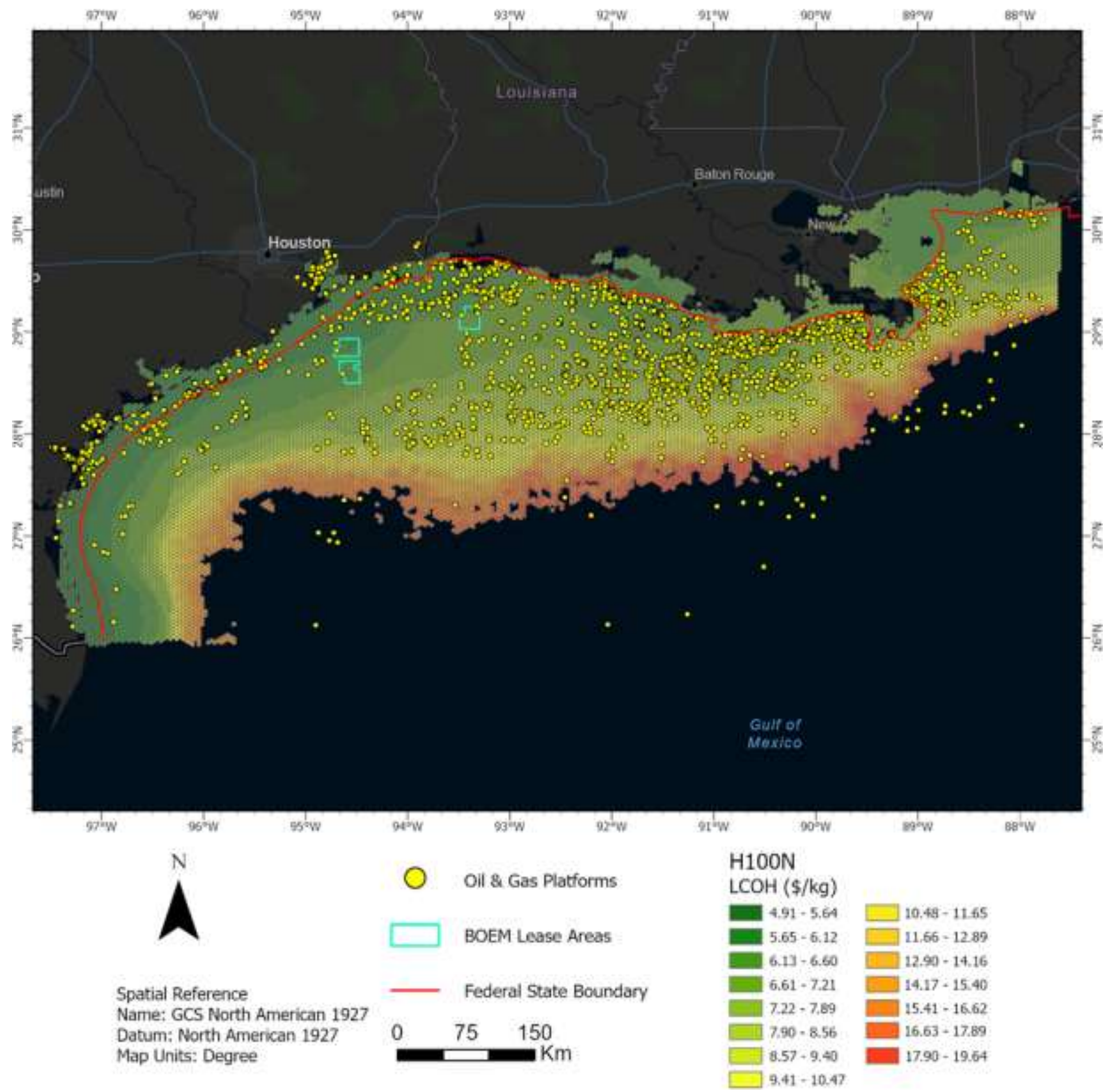


Figure 29: LCOH for power export H100N

Figure 30 compares the LCOH ranges for the above four hydrogen export cases to onshore steam methane reforming (SMR), steam methane with carbon capture, and electrolysis by wind or solar. The lighter green colored bars on the right for each of the project LCOH cases represent cases in water depths greater than 400 m. As can be seen from the figure, the project cases are all to the right of the onshore, with a significant cost differential to conventional hydrogen production through SMR and fossil fuel use. However, the gap is not as high when compared to hydrogen generated from low carbon energy. With a production or investment tax credit applied, the LCOH for offshore ROICE cases could potentially become competitive with onshore low carbon hydrogen. Having said that, it is not entirely clear if the other reference cases include applicable tax credits.

Figure 30: Levelized Cost of Hydrogen (LCOH) Comparison ($/kg H_2) (Bartlett & Krupnick, 2020).

Figure 31 (a-d) compares all four Hydrogen Export Cases on a common scale, enabling comparison and seeing the impact of project scale and comparing new build and repurposing cases.

On examining all these comparative heat maps and charts, similar conclusions can be drawn from comparing the LCOH cases as was done in comparing the LCOE cases:

- As expected, the range of LC for offshore renewable projects is higher than onshore renewables
- Hydrogen projects appear to be more competitive in the lower end of the LC range with onshore projects relative to equivalent power generation projects
- Repurposing helps reduce the LC for deeper water and/or far-shore locations
- Repurposing has a greater impact on small scale projects
- In several regions where repurposing does have a tangible impact, the overall LC is high even with repurposing, indicating challenging project economics

However, one unique conclusion for hydrogen generation cases is that levelized costs are similar for a wide range of project sizes. This would imply that small scale hydrogen projects with lower capex outlays could provide similar returns on invested capital as larger projects. Therefore, a lead case for repurposing projects could be a small scale near shore hydrogen project.

As mentioned earlier, these are screening level estimates with generalized assumptions. More definitive conclusions are expected to be drawn in Phase 2 where ROICE designs will be developed for specific assets with more accurate cost estimates and include all applicable credits to estimate more accurate project economics.

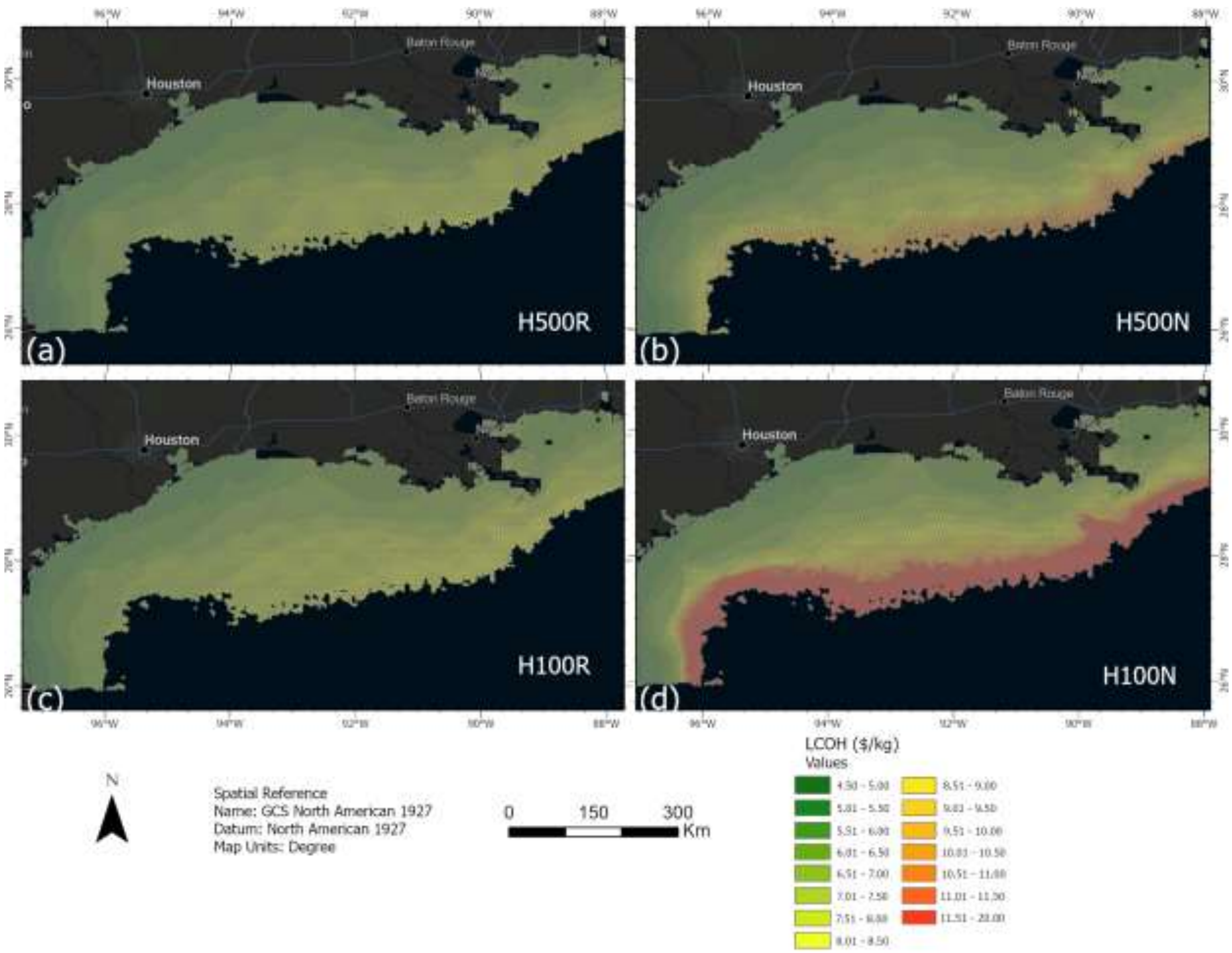


Figure 31: Four Hydrogen Export Cases on a common scale (a) H500R (b) H500N (c) H100R (d) H100N

3. Levelized Costs in BOEM Wind Lease Areas

As mentioned earlier, BOEM have announced three offshore Wind Energy Lease Areas in the Gulf of Mexico. The outlines of these can be seen below in Figure 32. An auction for these areas was recently concluded and the Lake Charles lease area was awarded to a bidder.

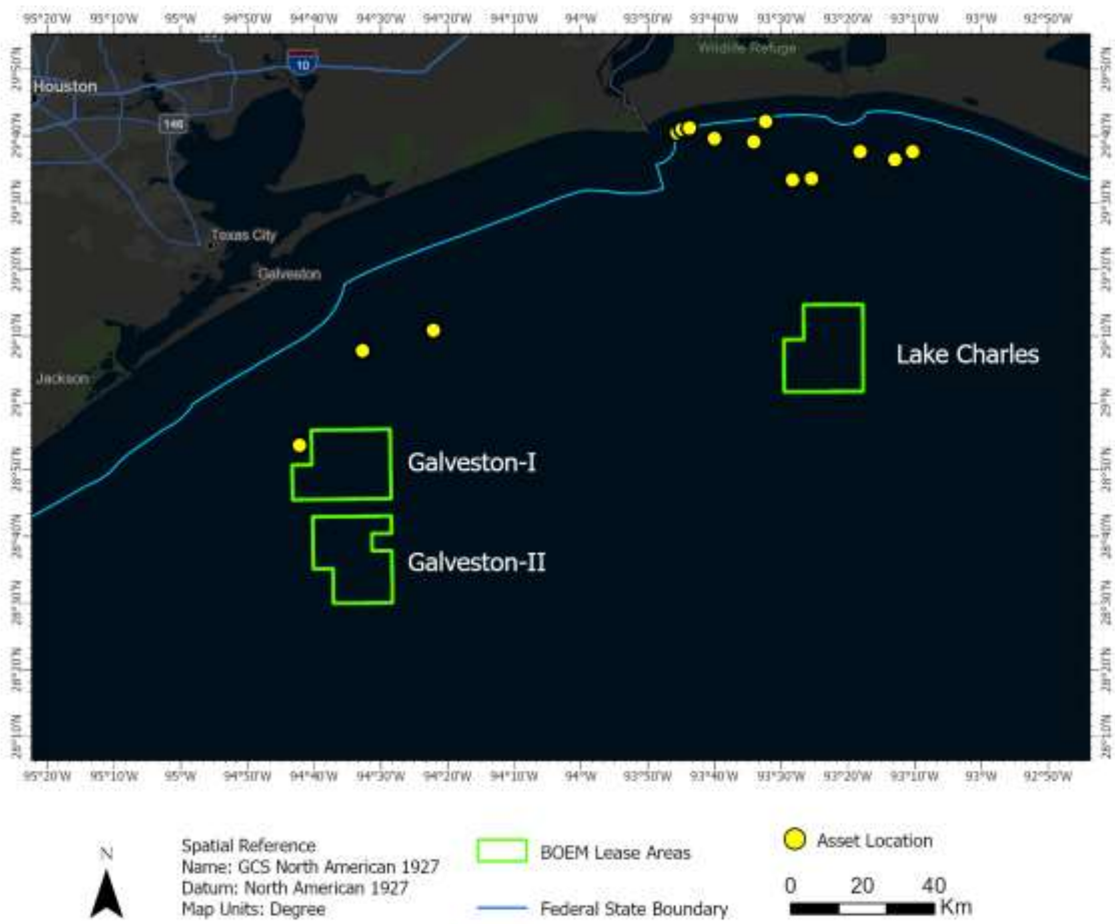


Figure 32: BOEM Lease area with nearby locations

Table 33 shows the average levelized costs for projects situated within these lease blocks for the eight different project configurations examined in this study. As can be seen, repurposing brings down the LC for all projects, but not significantly. No assets exist within these lease blocks, but several assets are in close proximity. These assets can be repurposed and connected to wind farms in the wind lease areas. Some of these assets will be studies in greater detail in Phase 2 to estimate economics for new and repurposed projects.

Table 33: LC Distribution over BOEM Lease Areas

Lease Blocks	E100N	E100R	E500N	E500R	H100N	H100R	H500N	H500R
Lake Charles	142.7	138.9	118.2	117.3	6.65	6.44	6.33	6.28
Galveston-I	136.3	134.5	108.0	107.6	6.15	6.04	5.89	5.87
Galveston-II	153.2	150.4	115.6	114.9	6.45	6.30	6.18	6.14

B. Analysis of Major Influences on Levelized Cost

LC values are a complex function of four primary variables:

- Wind speeds at the location determines power generation and hydrogen generation levels
- Project size dictates the size and cost of power and hydrogen generation equipment installed and supported
- Water depths determine foundation type – fixed or floating wind turbines for example
- Distance to shore determines the length and cost of power export cables, length of pipeline to be repurposed or newly installed for hydrogen

In addition, some factors have secondary influences:

- Water depth dictates the type of installation and maintenance vessels to be used
- Distance to shore, specifically distance to installation ports and O&M ports and power grid tie points, determines vessel days required for installation and maintenance

The distribution across the GOM of the above three geospatial variables follow different trends, with wind speeds forming east-west bands (Figure 17), water depths forming north-south bands (Figure 18), and distance to shore dependent on the variations of the coastline and the location of various ports (Figure 19). This results in a complex interrelation for costs and product generation making it hard to map trends to any one specific variable. Heat maps shown in the previous sections are therefore the best way to view the distribution across GOM. However, there are still a few learnings to be gleaned from looking at dependence on specific variables. That is done by looking at the capex components for the three representative locations.

The impact of wind speeds does not warrant much analysis since the average and variation is a given once the location is fixed. The higher the wind speed at the location, the more power or hydrogen generated for a given capex, thus reducing the LC. Instead, a focus on the impact of the other variables on capex is made. Including the capex savings from repurposing. The tables[(Table 34), (Table 35), (Table 36), (Table 37), (Table 38), (Table 39)] below summarize the major capex categories for the four power generation cases and the four hydrogen generation cases, for each of the three representative locations.

Location A

Table 34: Major CAPEX Breakdown: Location A (Shallow Water), Power Export; All Costs in M$

Major CAPEX Components	E100N	E100R	E500N	E500R
WTG costs	195.3	195.3	809.1	809.1
Structural costs (Foundations and Installations)	43.4	34.2	146.7	137.6
Cables	151.1	151.1	182.1	182.1
On-Shore Substation	2.0	2.0	4.2	4.2
Off-Shore Substation	3.8	3.8	15.8	15.8
Project Development Fixed costs	97.6	97.6	404.2	404.2
Total CAPEX	493.2	484.0	1562.2	1553.0

Table 35: Major CAPEX Breakdown: Location A (Shallow Water), Hydrogen Export; All Costs in M$

Major CAPEX Components	H100N	H100R	H500N	H500R
Electrolyzer	48.0	48.0	216.0	216.0
Structural costs (Foundations and Installations)	10.5	1.3	10.5	1.3
Compressor	3.9	3.9	14.6	14.6
Desalination	1.2	1.2	3.4	3.4
Pipeline	74.8	26.2	74.8	26.2
Power Generation	339.0	339.0	1404.2	1404.2
Project Development costs	3.2	2.7	12.2	11.8
Total CAPEX	484.3	423.5	1,739.4	1,678.7

Location B

Table 36: Major CAPEX Breakdown: Location B (Shallow Water), Power Export; All Costs in M$

Major CAPEX Components	E100N	E100R	E500N	E500R
WTG costs	195.3	195.3	809.1	809.1
Structural costs (Foundations and Installations)	36.2	29.3	123.8	116.8
Cables	147.4	147.4	178.2	178.2
On-Shore Substation	2.0	2.0	4.2	4.2
Off-Shore Substation	3.8	3.8	15.8	15.8
Project Development Fixed costs	97.6	97.6	404.2	404.2
Total CAPEX	482.4	475.5	1,535.3	1,528.4

Table 37: Major CAPEX Breakdown: Location B (Shallow Water), Hydrogen Export; All Costs in M$

Major CAPEX Components	H100N	H100R	H500N	H500R
Electrolyzer	48.0	48.0	216.0	216.0
Structural costs (Foundations and Installations)	8.4	1.4	8.4	1.4
Compressor	3.6	3.6	13.5	13.5
Desalination	1.2	1.2	3.4	3.4
Pipeline	73.0	25.5	73.0	25.5
Power Generation	333.8	333.8	1382.9	1382.9
Project Development costs	3.1	2.7	12.6	11.7
Total CAPEX	474.7	417.6	1,713.0	1,655.8

Location C

Table 38: Major CAPEX Breakdown: Location C (Deeper Water), Power Export; All Costs in M$

Major CAPEX Components	E100N	E100R	E500N	E500R
WTG costs	195.3	195.3	809.1	809.1
Structural costs (Foundations and Installations)	251.4	90.1	527.4	366.2
Cables	283.7	283.7	332.8	332.8
On-Shore Substation	19.1	19.1	79.0	79.0
Off-Shore Substation	22.9	22.9	94.8	94.8
Project Development Fixed costs	97.6	97.6	404.2	404.2
Total CAPEX	869.9	708.6	2,247.3	2,086.1

Table 39: Major CAPEX Breakdown: Location C (Deeper Water) Hydrogen Export; All Costs in M$

Major CAPEX Components	H100N	H100R	H500N	H500R
Electrolyzer	48.0	48.0	216.0	216.0
Structural costs (Foundations and Installations)	163.5	2.3	163.5	2.3
Compressor	3.4	3.4	12.7	12.7
Desalination	1.2	1.2	3.4	3.4
Pipeline	323.1	113.1	323.1	113.1
Power Generation	415.7	415.7	1731.5	1731.5
Project Development costs	10.8	2.7	19.8	11.7
Total CAPEX	981.8	592.0	2,486.3	2,096.5

Some key screening-level assumptions influencing the data in the tables above are listed below. All assumptions will be refined further in Phase 2. Key dependencies are also discussed here:

- For power projects, the structural costs primarily represent the foundations for the wind turbines – fixed or floating, depending on water depth. Also included for new build projects are costs for the platform for supporting infrastructure.

- For hydrogen projects, the structural costs are only the costs for the platform for supporting infrastructure. This cost is minimal for repurposing projects. The structural costs for the wind turbines supplying the power to the hydrogen system are lumped into the power generation costs.
- Export cables are assumed to cost the same irrespective of the power transport output of the project. This assumption will be refined in Phase 2.
- Pipeline costs are also the same for small and large projects. For new build projects, an oversized pipeline is assumed to lower the operating pressure and minimize pipeline embrittlement. For repurposed pipelines, the use of existing natural gas or oil pipelines is assumed which are typically 12" in diameter or larger – these are capable of carrying the hydrogen generated by projects larger than the 500MW commercial case studied here. In both cases, this also allows saving costs by moving the compressor onshore.
- The cost of repurposing pipelines is based on a screening level assumption of 35% of the cost of laying a brand-new pipeline to restore the pipeline to operating conditions, carry out surveys, make connections to the offshore hydrogen system and onshore delivery point etc.
- Compression cost for hydrogen projects is location dependent since wind speeds vary with location and the power and hydrogen generated can vary as a result.

The tables below summarize the key capex influencers for power (Table 40) and hydrogen projects (Table 41):

Table 40: Power Project CAPEX influencers

Power Projects: Capex Influencers	**Project Size**	**Water Depth**	**Distance to Shore**	**Repurposing**
WTG costs	√			
Structural Costs	√	√		√
Cables			√	
On-Shore Substation	√			
Off-Shore Substation	√		√	

Table 41: Hydrogen Project CAPEX influencers

Hydrogen Projects: Capex Influencers	**Project Size**	**Water Depth**	**Distance to Shore**	**Repurposing**
Electrolyzer	√			
Structural Costs		√		√
Pipeline			√	√
Compressor	√			
Desalination	√			

A few observations on the above table:

- Project size is a major influence on project capex, as expected. Most of the costs scale with the size of the projects.
- Water depth has a strong influence on structural costs – floating vs fixed structures for the wind turbines, and in the case of new build projects, for the equipment support platform as well.
- Structural cost in general does not depend on the distance to shore; rather they depend on the water depths in which the structure is installed. Installation and maintenance costs do increase with distance from shore but this is secondary in nature.
- Distance to shore influences the two product delivery components – export cables and pipelines. As a result of simplifying assumptions made in Phase 1, these costs do not scale with project size. The underlying technical basis for these assumptions is discussed elsewhere in this report.
- Distance to shore also influences the Off-shore Substation (OSS) cost mainly because of the transition from HVAC to HVDC transmission type is a function of distance.
- Repurposing has an impact on structural costs through the reuse of existing oil & gas structures to house electrical support equipment and hydrogen generation equipment. New build projects will have to incur the cost of a new platform. Repurposing pipelines also has an impact on capex, avoiding the cost of a newly installed pipeline.

The impact of repurposing on project capex for different project configurations is shown in the Table 42

Table 42: % CAPEX reduction due to Repurposing

Capex Reduction from Repurposing

Power	Shallow	Deep
435 MW	99%	93%
105 MW	98%	81%

Hydrogen	Shallow	Deep
435 MW	97%	85%
105 MW	88%	61%

Conclusions from the above analysis are as follows:

- The impact of repurposing increases with water depth (with a corresponding influence of distance to shore) and for smaller projects. This can be attributed to higher structural costs avoidance in deeper waters from reusing existing structures
- Repurposing has a greater impact on hydrogen projects from the reuse of pipelines to bring hydrogen to shore.

Table 43 compares capex outlay for power projects and the equivalent power to hydrogen projects.

Table 43: Hydrogen CAPEX compared to Power CAPEX

Hydrogen Capex vs Power Capex

Repurposed	Shallow	Deep
435 MW	108%	100%
105 MW	87%	83%

New Build	Shallow	Deep
435 MW	111%	110%
105 MW	97%	111%

There are some interesting conclusions that can be drawn from the above analysis:

- The above figures represent a tradeoff between export cables and offshore substation for a power project vs. avoiding those costs and instead incurring the costs of the hydrogen generation components.
- When this tradeoff is compared for the cases above, it is clear that minimal additional capex is needed to export hydrogen vs power. In some cases, especially for repurposed small-scale projects, the tradeoff results in a capex reduction.
- The incremental economics on the additional capex for hydrogen generation is likely to look quite promising in all cases, especially considering the healthier federal incentives for hydrogen production vs wind power generation.

In Phase 2, all these conclusions will be vetted further for specific locations and actual project economics will be compared.

C. Levelized Cost Trends for Asset Locations

As discussed in Section III.G above, the levelized cost heat maps were used to assign LC values and other parameters to each of the ~1700 assets in the GOM. To improve the understanding of the impact of various factors on levelized cost, a switch is now made from heat maps to this asset database. Each data point shown in the graphs in this section represents an asset location in the GOM.

a) Power Generation Projects

Figure 33 shows the relationship between water depth and levelized cost for power generation projects. The LC values for the two project sizes (500 and 100) and for new and repurposed (N and R) cases are compared. Figure 34 zooms in on assets in water depths up to 200m.

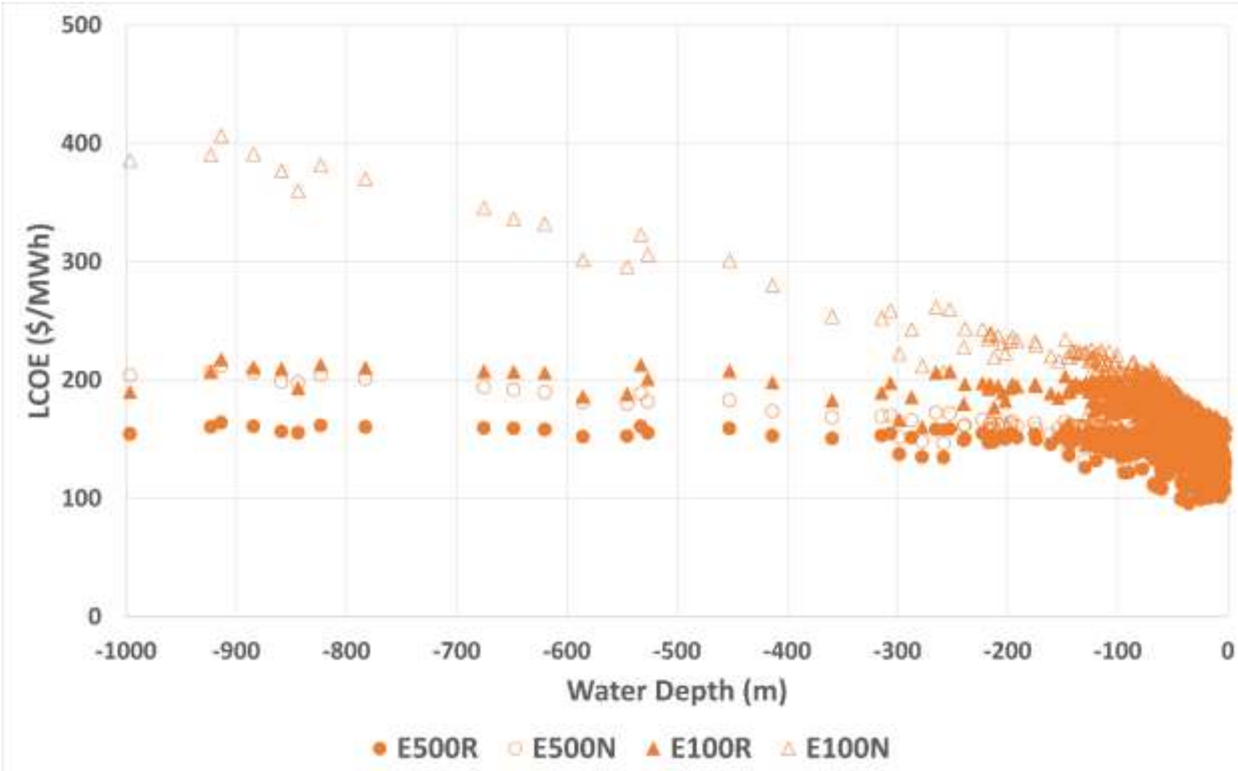


Figure 33: Impact of Water Depth on LC for Power Export Projects

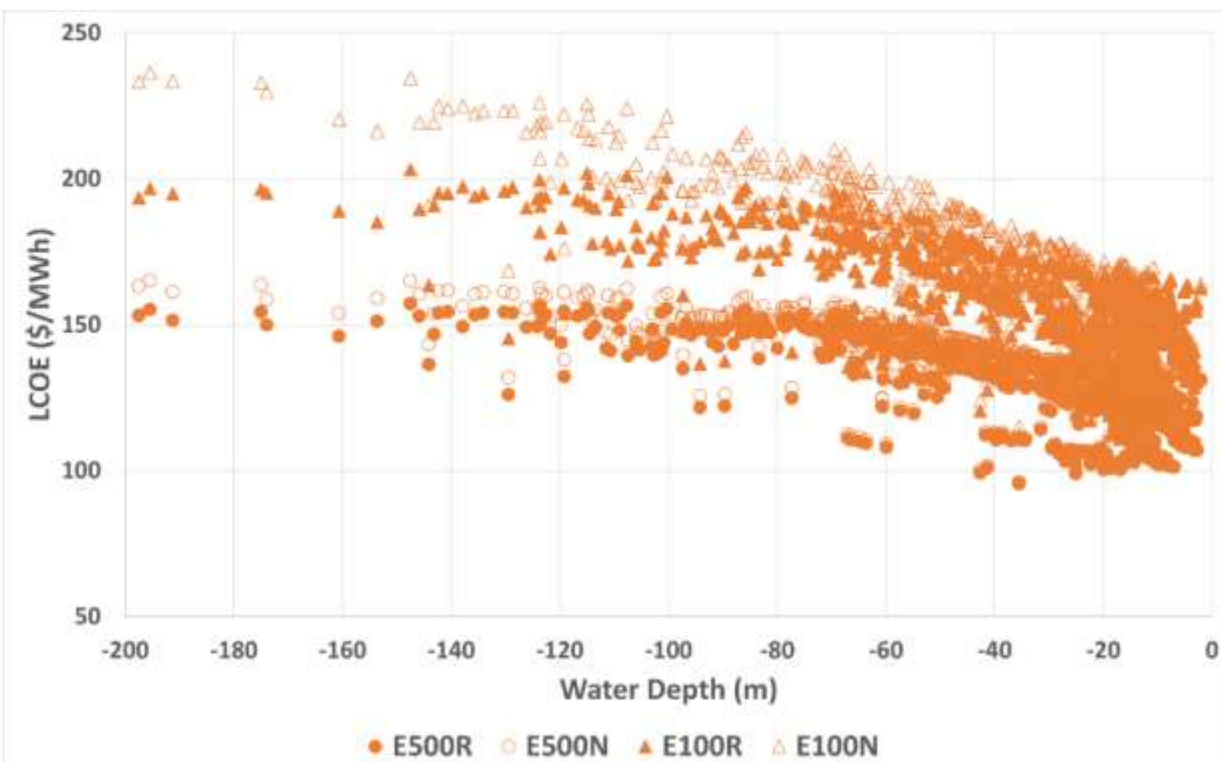


Figure 34: LC Variation for Power Projects in Shallow Water

The lesser degree of correlation of LC values for assets at water depths less than 50 m reflects the higher proportional impact of wind speeds at these locations on the levelized cost. As mentioned earlier, the correlation between water depth and wind speed is weak with wind speed trending from west to east, rather than with water depth. Therefore, for assets in similar water depths, wind speeds can be quite different, resulting in varying levels of power generation and a variance in LC.

Looking past this near shore cluster, two distinct slope lines can be seen– one up to about ~80 m of water depth and one in deeper waters. These slopes are more evident in Figure 35 which shows the correlation between capex for power export projects and water depth. There are multiple reasons for this slope change.

- Switching from HVAC transmission systems to HVDC. While this is a switch driven by distance to shore than water depth (as explained in III.C.5.b)), generally speaking, deeper water assets are further from shore.
- When the transmission system changes to HVDC, the cost of cables per meter comes down by more than half (III.C.6.d)), driving a reduction in the slope of capex (and LC) vs water depth. However, for assets further from shore, the project will need greater lengths of cable to bring the power to shore.
- Switching from fixed to floating wind turbine foundations. Floating foundations costs are not affected by water depth as discussed in section III.C.6.b).
- Installation and maintenance costs also could be higher for these assets.

The net effect of all these factors is a much slower increase in capex and LC for deeper water assets.

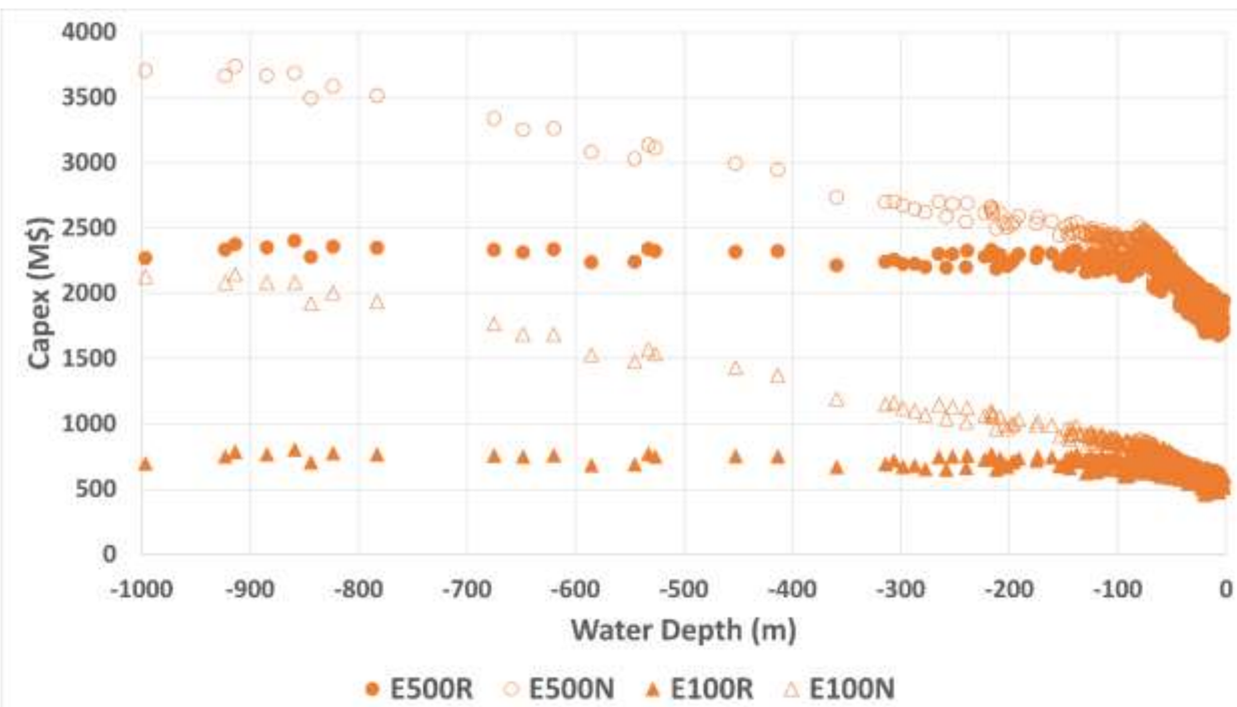


Figure 35: Impact of Water Depth on Project Capex for Power Export

Figure 35 and Figure 36 also indicate that larger projects are a more efficient investment of capital, reflected by the lower LCs for the E500 projects, especially in deeper waters. For new build projects, comparing the slope of CAPEX vs water depth (Figure 35) and LC vs water depth (Figure 33), it is clear that the larger E500N projects compensate for the capex increase with higher power outputs reducing the slope of LC vs water depth. The increase in capex for smaller projects on the other hand outpaces the power output, resulting in a steep increase in LC with water depth. Thus, smaller new build projects may not be viable in deeper waters / further from shore locations. Project size has an impact on LC's for repurposing projects (E500R and E100R) as well, although the improvements in LC is not as pronounced as in new build projects because of the buffering effect of reusing existing structures.

Repurposing reduces the capex and LC by a greater percentage for smaller projects. This is because the foundation/platform costs represent a greater fraction of total project costs compared to larger scale projects where the WTG and other costs dominate. This also explains the relatively lower slope of LC vs depth for repurposed projects versus new build. Once you take the jacket out of the picture, the remaining components are less sensitive to water depth. The main reason for the gradual increase in LC in deeper waters for repurposed projects is increased installation and maintenance costs due to a longer distance to ports for these deeper water locations.

It is also clear from Figure 34 that if a smaller project is planned for deeper waters, repurposing an existing structure can significantly reduce the LC by as much as half for a repurposed project (E100R) vs a new build one (E100N).

b) Hydrogen Generation Projects

Figure 36 shows the relationship between water depth and levelized cost for hydrogen generation projects. The LC values for the two project sizes (500 and 100) and for new and repurposed (N and R) cases are compared. Figure 37 zooms in on assets in water depths up to 200m.

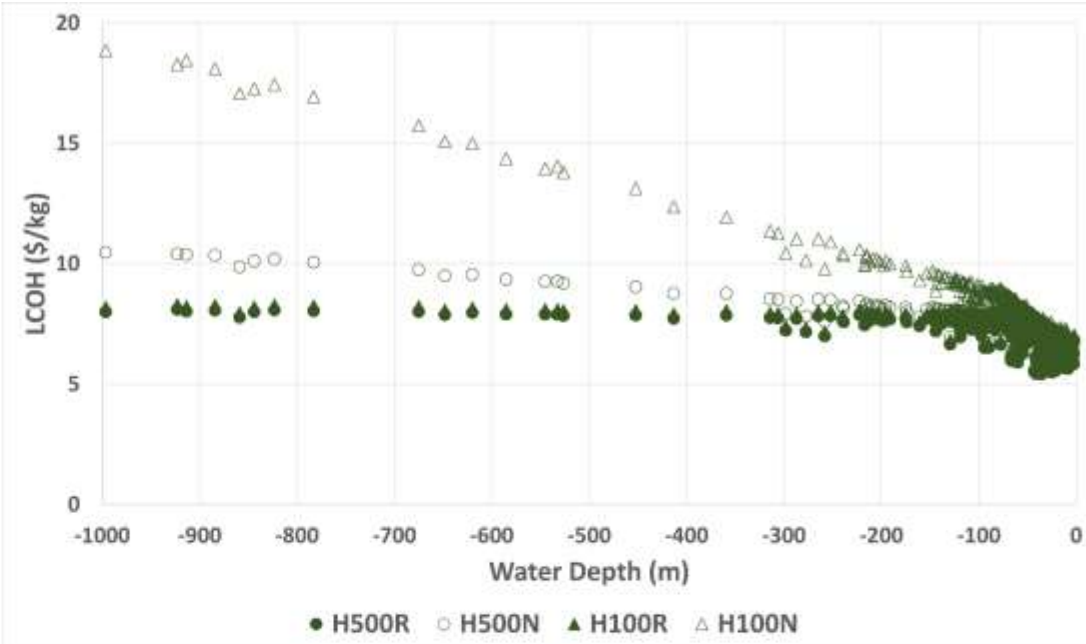


Figure 36: Impact of Water Depth on LC for Hydrogen Export Projects

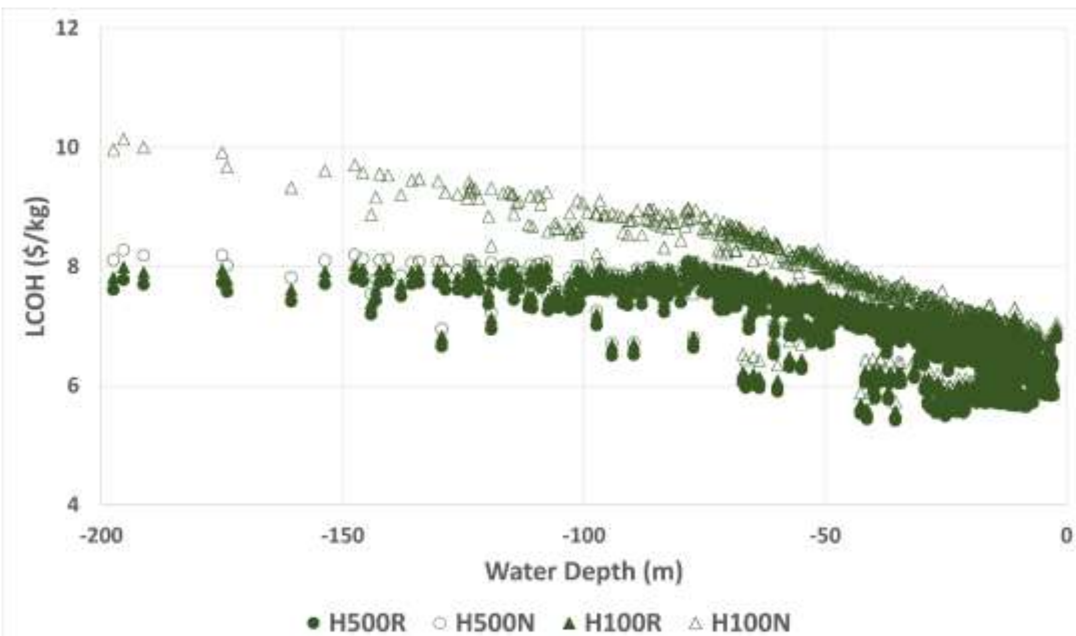


Figure 37: LCOH vs Water Depth for Shallow Water Assets

As noted before, power supply to these hydrogen projects is from equivalent wind power projects. Other than not needing power export cables and onshore substations, the power generation equipment is the same. Therefore, some of the observations made in comparing power projects in the previous section on power projects apply to hydrogen projects as well.

- The large cluster of LC values for assets at water depths less than 50 m reflects the greater impact of wind speeds at these locations on the levelized cost relative to water depth. Depending on the east-west location of the shallow water asset, wind speeds can be quite different, resulting in varying levels of power generation and resulting hydrogen generation.

- Looking past this near shore cluster, two distinct slope lines can be seen– one up to about ~80 m of water depth and one in deeper waters. These slopes are more evident in Figure 38 which shows the correlation between capex for power export projects and water depth. The primary driver for the lower slope in deeper waters for hydrogen systems is the switch from fixed foundations for the wind turbines (whose costs go up with water depth) to floating foundations (whose costs are less dependent on water depths).
- Other factors impacting the slope that were relevant for power generation projects discussed in Section IV.C.a), such as cable costs and transmission system impacts, are not applicable to hydrogen systems.
- Just as in the power projects, distance to shore impacts LC. Generally speaking, deeper water assets are further from shore, so these impacts are also seen in correlations to water depth. For these locations, a hydrogen export project will need to repurpose greater lengths of pipeline to bring the hydrogen to shore or lay greater lengths of new pipelines. Installation and maintenance costs also depend on distance to shore.
- For new build hydrogen projects, as for power projects, project size has an impact. Larger projects are more capital efficient and result in reduced LC at a given water depth. This is not true for repurposed projects as discussed below.

There are a few trends that are unique to hydrogen projects:

- As can be seen in Figure 40 below, the costs for repurposed hydrogen projects (H500R and H100R) increase only slightly with water depth beyond water depths greater than ~100m. This is because once the depth-dependent cost of a support equipment platform structure is eliminated through repurposing, the costs of the rest of the hydrogen project components are not dependent on water-depth. There is a secondary dependence on distance to shore for installation and maintenance costs, but this does not impact the LC’s significantly.
- A corollary of the above trend is that for new build projects, there is a strong depth dependence for capex and LC. (Figure 38) Therefore, it is advantageous to consider repurposing options for deeper water / further from shore hydrogen projects. Of course, these projects are challenged with high LC’s even after repurposing, so further optimization and greater production incentives are needed to make these projects attractive.

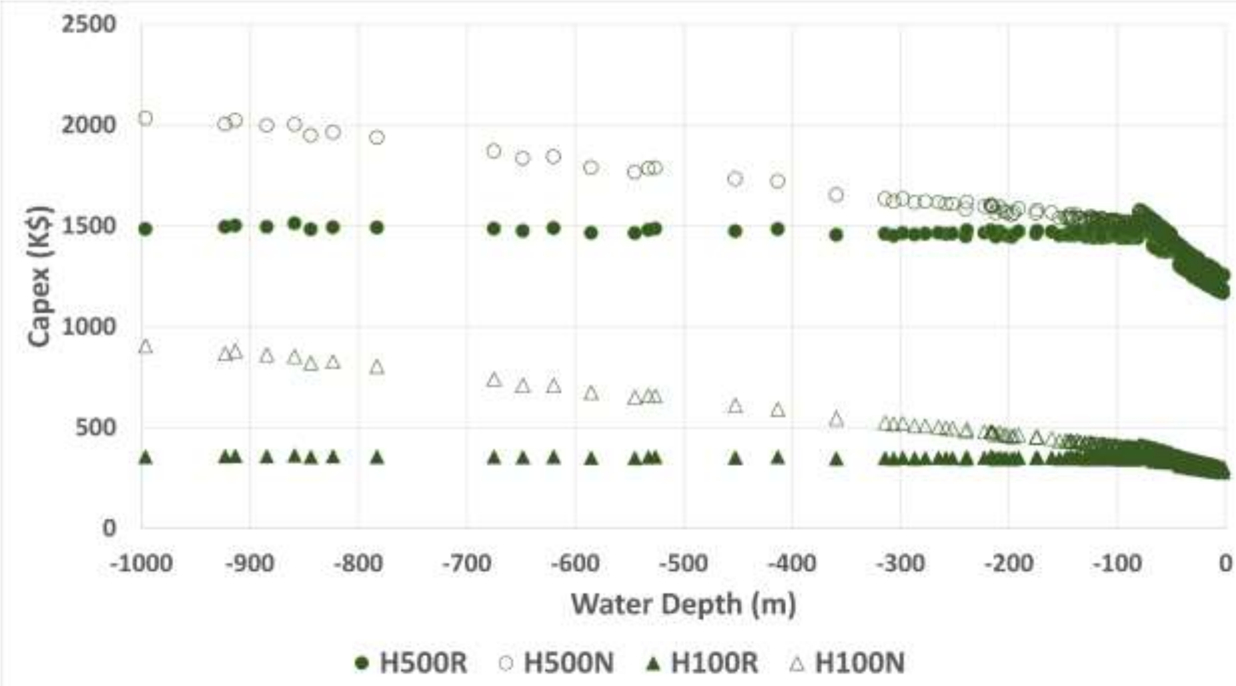


Figure 38: Impact of Water Depth on Project Capex for Hydrogen Export

- Eliminating the cost of the support structure platform through repurposing also removes the dependence of hydrogen project LC's on project size. This can be seen Figure 38 and where H500R and H100R points lie almost on top of each other. This is because the other hydrogen project cost components scale in direct proportion to project size and resulting hydrogen generation. Power export projects do not have this advantage, since cable costs are a stronger function of distance to shore, and do not scale with the amount of power being exported.
- Repurposing thus has dual advantages for hydrogen projects in deeper water / further from shore locations – it limits the increase in capex and LC for these locations relative to shallow water / near shore locations, and it also eliminates the need for increasing project size to capture economies of scale. These advantages may make it more attractive to implement hydrogen export projects in these locations versus power export projects.

c) *Impact of Repurposing*

This section takes a deeper look at the impact of repurposing on levelized cost (and therefore ROICE project economics). A % reduction in LC for each asset resulting from repurposing was calculated. This is done for each of the four cases – E500, E100, H500 and H100 – by taking the ratio of the levelized cost for the repurposed project (R) to the corresponding new build project (N). Figure 39 plots the % Reduction in LC as a function of water depth for each of the ~1700 assets in the GOM.

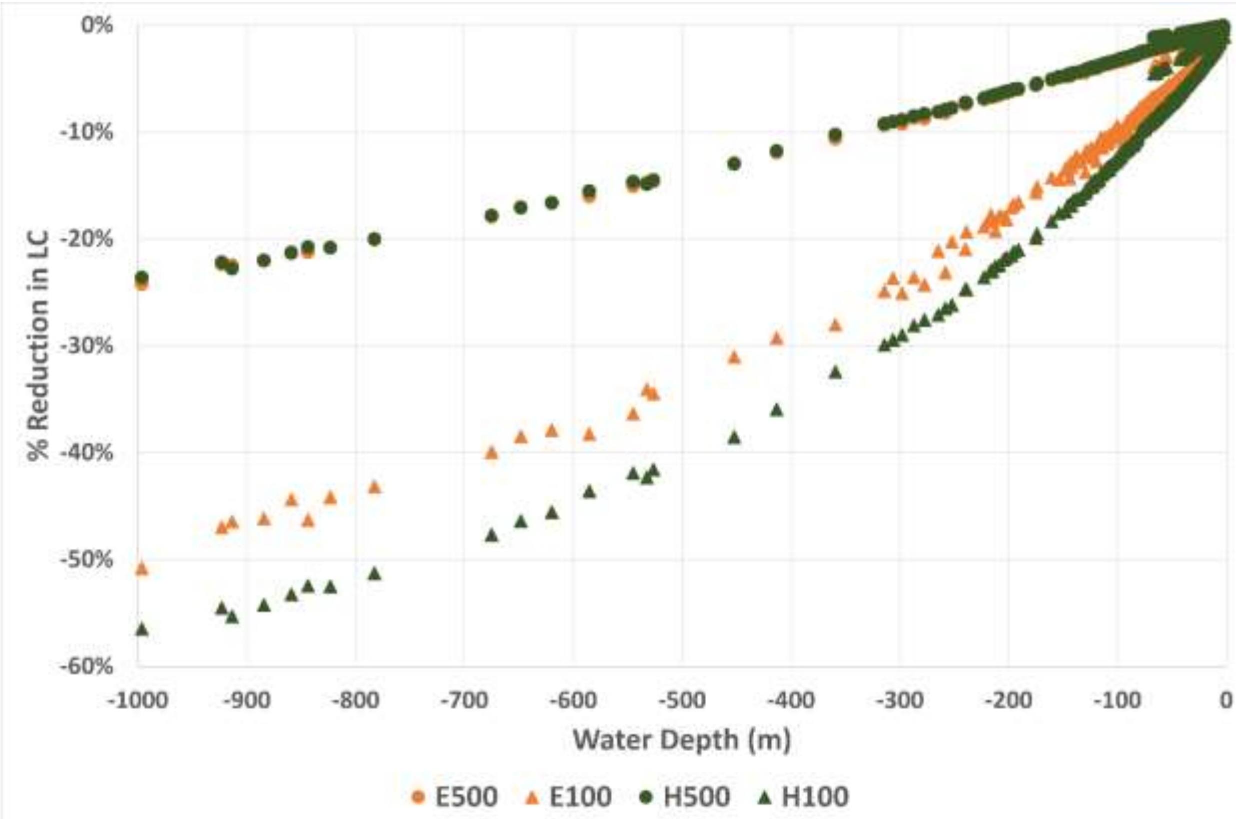


Figure 39: Levelized Cost Reduction from Repurposing

As can be seen, repurposing appears to have a greater impact for deeper water projects. This can be ascribed to cost-avoidance, through repurposing, of an increasingly expensive new build platform to support the power and hydrogen infrastructure as the water depth increases. Repurposing also appears to have a greater impact on smaller projects. This is because the cost of the support platform forms a greater fraction of the total capex for smaller projects. Therefore, saving on those costs by reusing existing structures results in a larger LC reduction. Further reusing pipelines to bring hydrogen back to shore allows for a greater % LC reduction for smaller hydrogen projects.

D. Asset Shortlisting for Phase 2

In Phase 2, more detailed ROICE project definitions including project economics will be developed for about 50 of the 1568 assets in the GOM. The shortlisting criteria is described and the resulting list of assets is provided here.

As mentioned above, the heat maps generated by the ROICE LC model was used to estimate the LC for all eight reference cases for each asset in the GOM. Asset information was obtained from the BSEE database (Bureau of Safety and Environment Enforcement (BSEE) Data Center, 2023). A first round of shortlisting was conducted based on the following criteria:

- Assets still in service or that have not yet been removed
- Assets installed in 1990 or after to increase potential for remaining structural integrity
- Asset type was "fixed" – eliminating caissons, well head platforms, temporary and auxiliary structures etc.

A ranking exercise was then carried out on these remaining assets to identify those that had favorable LC for any project scenario, using the following process:

- For each project scenario (E500R, H550N etc.) assets were ranked on the basis of LC and assets that were in the top quartile of the LC distribution for each scenario were selected
- A composite hydrogen project rank, combining the rank of an asset for each of the four hydrogen project scenarios was developed; a similar composite power project rank was also developed.
- The top 40 assets that had favorable hydrogen and power project ranks formed the final shortlist (Table 44)

Table 44: Shortlist of 40 Assets to be studies in Phase 2

Asset Details								Power	Hydrogen	Total	LC for Hydrogen $/kg				LC for Power $/MWh			
OBJECTID	Area Code	Block #	Auth. Status	Bus Asc Name	Install Date	Latitude	Longitude	Proj Rank	Proj Rank	Rank	H500R	H100R	H500N	H100N	E500R	E100R	E500N	E100N
1404	WC	48	<Null>	Cox Operating, L.L.C.	2/20/2000	29.68298	-93.7474	1	4	5	5.72	5.89	5.73	5.92	101.26	115.58	101.41	116.19
1393	WC	48	TERMIN	Energy XXI GOM, LLC	10/14/2002	29.65965	-93.6673	4	3	7	5.71	5.88	5.72	5.92	102.02	118.71	102.22	119.51
1440	WC	48	UNIT	Cox Operating, L.L.C.	11/15/2003	29.68602	-93.7292	2	6	8	5.72	5.89	5.73	5.92	101.26	115.58	101.41	116.19
1384	WC	44	PROD	Sanare Energy Partners, LLC	5/24/2003	29.65248	-93.569	8	2	10	5.70	5.87	5.72	5.93	103.30	123.86	103.54	124.83
1392	WC	48	UNIT	Cox Operating, L.L.C.	6/9/2000	29.67495	-93.7604	3	8	11	5.73	5.90	5.74	5.94	101.70	116.43	101.87	117.10
1400	WC	21	PROD	Sanare Energy Partners, LLC	10/6/2005	29.70257	-93.54	5	14	19	5.78	5.95	5.79	5.99	102.86	118.41	103.02	119.06
370	HI	176	TERMIN	Walter Oil & Gas Corporation	2/14/2011	29.18171	-94.3699	10	9	19	5.74	5.91	5.76	5.99	104.93	127.71	105.28	129.10
1405	WC	95	TERMIN	Energy XXI GOM, LLC	1/3/2005	29.55721	-93.4719	16	5	21	5.71	5.88	5.72	5.93	105.35	131.55	105.61	132.55
288	GA	209	PROD	Arena Offshore, LP	10/13/1999	29.12999	-94.546	6	15	21	5.73	5.90	5.75	5.98	102.66	119.10	103.03	120.57
380	HI	176	TERMIN	Walter Oil & Gas Corporation	4/9/2012	29.1816	-94.3698	11	11	22	5.74	5.91	5.76	5.99	104.93	127.71	105.28	129.10
292	GA	209	PROD	Arena Offshore, LP	8/9/1996	29.13026	-94.5466	7	16	23	5.73	5.90	5.75	5.98	102.66	119.10	103.03	120.57
443	MI	657	TERMIN	Matagorda Island Gas Operations, I	5/15/2008	28.04209	-96.605	23	1	24	5.58	5.72	5.60	5.81	104.79	136.91	105.24	138.67
1391	WC	96	UNIT	Talos Third Coast LLC	9/3/2004	29.5597	-93.4244	19	7	26	5.71	5.89	5.73	5.94	105.52	131.98	105.77	132.97
294	GA	288	RELQ	Blue Dolphin Pipe Line Company	4/25/2001	28.8936	-94.7042	9	26	35	5.82	5.99	5.84	6.08	105.12	126.77	105.55	128.48
654	SM	217	UNIT	Cox Operating, L.L.C.	8/30/2004	29.44075	-92.0612	24	18	42	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
1439	WC	62	TERMIN	Energy XXI GOM, LLC	7/27/2004	29.62733	-93.3032	34	10	44	5.75	5.92	5.76	5.98	107.26	137.06	107.53	138.10
676	SM	217	UNIT	Cox Operating, L.L.C.	9/5/2004	29.44066	-92.062	26	19	45	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
88	EI	10	PROD	Contango Operators, Inc.	1/8/2008	29.38232	-91.7799	12	33	45	6.08	6.23	6.06	6.25	107.11	128.40	107.21	128.78
785	SM	217	UNIT	Cox Operating, L.L.C.	6/9/2011	29.44133	-92.0621	27	20	47	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
1473	WC	62	TERMIN	Energy XXI GOM, LLC	12/21/2007	29.62748	-93.3029	35	12	47	5.75	5.92	5.76	5.98	107.26	137.06	107.53	138.10
169	EI	10	PROD	Contango Operators, Inc.	2/7/2007	29.3836	-91.7687	13	34	47	6.06	6.23	6.06	6.25	107.11	128.40	107.21	128.78
789	SM	217	UNIT	Cox Operating, L.L.C.	10/18/2009	29.44043	-92.0611	28	21	49	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
268	EI	32	PROD	Cox Operating, L.L.C.	1/1/1993	29.31151	-91.5354	20	29	49	5.91	6.09	5.92	6.11	107.49	130.19	107.57	130.52
252	EI	10	PROD	Contango Operators, Inc.	1/8/2008	29.38232	-91.7799	14	35	49	6.08	6.23	6.06	6.25	107.11	128.40	107.21	128.78
791	SM	217	UNIT	Cox Operating, L.L.C.	5/1/2009	29.4418	-92.0619	29	22	51	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
97	EI	11	Approved	Contango Operators, Inc.	5/17/2008	29.37895	-91.7529	15	36	51	6.08	6.23	6.06	6.25	107.16	128.68	107.27	129.09
782	SM	212	UNIT	Cox Operating, L.L.C.	6/21/2008	29.47323	-92.0487	25	27	52	5.87	6.05	5.88	6.07	107.83	133.59	107.92	133.95
1431	WC	73	RELINQ	Talos Third Coast LLC	10/12/2003	29.60715	-93.2159	39	13	52	5.75	5.92	5.76	5.98	108.10	140.13	108.36	141.14
800	SM	217	UNIT	Cox Operating, L.L.C.	7/4/2008	29.44136	-92.0625	30	23	53	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
804	SM	217	UNIT	Cox Operating, L.L.C.	6/22/2008	29.44137	-92.062	31	24	55	5.84	6.01	5.85	6.03	107.75	134.95	107.84	135.32
103	EI	11	Approved	Contango Operators, Inc.	3/17/2008	29.37895	-91.7529	17	38	55	6.08	6.23	6.06	6.25	107.16	128.68	107.27	129.09
195	EI	11	Approved	Contango Operators, Inc.	9/4/2010	29.37864	-91.753	18	39	57	6.06	6.25	6.06	6.25	107.16	128.68	107.27	129.09
1457	WC	65	RELINQ	Apache Corporation	4/22/2003	29.62776	-93.1721	40	17	57	5.83	5.97	5.84	6.03	110.44	144.18	110.71	145.25
441	MI	622	TERMIN	Apache Corporation	1/1/1995	28.10214	-96.3699	33	25	58	5.76	5.90	5.78	6.01	106.29	137.25	106.83	139.41
92	EI	10	PROD	Contango Operators, Inc.	6/12/2006	29.3759	-91.7842	21	37	58	6.29	6.25	6.08	6.28	107.94	130.62	108.05	131.04
690	SM	223	UNIT	Cox Operating, L.L.C.	3/10/2004	29.40901	-91.9923	32	28	60	5.88	6.06	5.89	6.08	108.12	134.12	108.22	134.51
194	EI	10	PROD	Contango Operators, Inc.	4/27/2007	29.37041	-91.7817	22	40	62	6.08	6.29	6.08	6.28	107.94	130.62	108.05	131.04
783	SM	223	UNIT	Cox Operating, L.L.C.	8/2/2003	29.4087	-91.9923	36	30	66	5.88	6.06	5.89	6.08	108.12	134.12	108.22	134.51
80	EI	39	PROD	Cox Operating, L.L.C.	5/1/2000	29.26035	-91.4804	37	31	68	5.93	6.11	5.94	6.13	109.08	135.30	109.19	135.76
250	EI	39	PROD	Cox Operating, L.L.C.	12/20/2004	29.26031	-91.4804	38	32	70	5.93	6.11	5.94	6.13	109.08	135.30	109.19	135.76

Figure 40 below shows the geographical locations of these 40 assets. As can be seen, and as expected from the results discussed previously, many of these assets are close to shore. To examine other classes of assets, an additional ten assets will be added to make up the full list of 50 assets that will be studied in detail in Phase 2. It is also expected that the list will change as more is learned about some of these assets. This thus merely represents a starting point for Phase 2 studies.

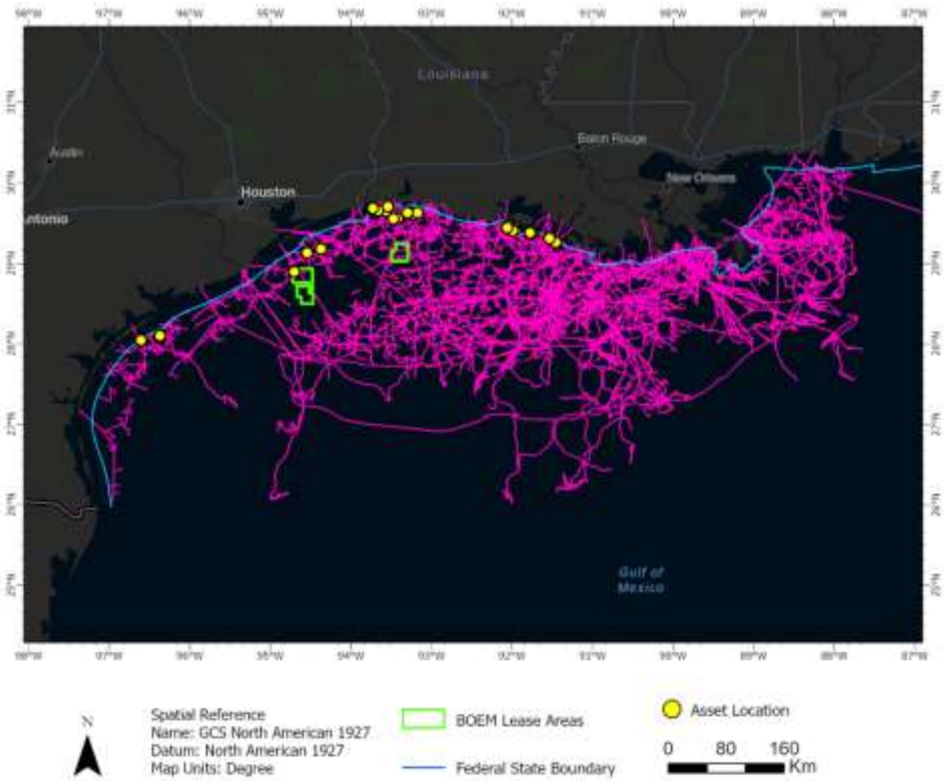


Figure 40: Asset Shortlist

V. Conclusion and Future Studies

A. Conclusions:

1. ROICE LC Model

As the 1500 plus oil & gas structures in the US Gulf of Mexico (GOM) reach the end of their oil & gas phase, these structures as well as the thousands of miles of pipelines have the potential to be converted into ROICE (Repurposing Offshore Infrastructure for Clean Energy) projects. Repurposing is the re-use of some or all of the existing infrastructure for a new project. A comprehensive model has been developed for estimating levelized costs (LC) for such projects. The ROICE LC Model can estimate LC's for wind power and hydrogen generation for both new build projects as well as projects that repurpose some of the existing oil & gas infrastructure.

Using this model, heat maps have been generated that show LC distributions for different project scenarios across the GOM. These scenarios include new build and repurposed versions of wind and hydrogen projects at two different project sizes (demonstration scale and commercial scale). These heat maps have been analyzed to identify favorable locations for ROICE projects, how they compare with onshore and other alternatives, and to understand the impact of various key variables and cost elements on LC.

The LC heat maps were used to estimate screening level LC values for each of the ~1500 assets in the GOM to identify favorable locations for different versions of ROICE projects. A shortlist of 50 assets has been developed for more detailed study in Phase 2 of this project.

LC values are a complex function of several variables:

- Wind speeds at the location determines power generation and hydrogen generation levels. Average wind speeds are higher for western GOM locations and close to shore.
- Project size dictates the size and cost of power and hydrogen generation equipment installed and supported. Most of the costs scale with the size of the projects with the notable exception of power export cables and pipelines foo hydrogen export.
- Water depths determine structural foundation type and costs for the wind turbines and the platform hosting the support infrastructure for power and hydrogen generation
- Distance to shore determines the length and cost of power export cables, length of pipeline to be repurposed or newly installed for hydrogen. It also influences offshore substation costs due to the transition from HVAC transmission type near shore to HVDC further away from shore.
- Repurposing has an impact on structural costs through the reuse of existing oil & gas structures to house electrical support equipment and hydrogen generation equipment. New build projects will have to incur the cost of a new platform. Repurposing pipelines also has an impact on capex, avoiding the cost of a newly installed pipeline.

In addition, some variables have secondary influences:

- Water depth dictates the type of installation and maintenance vessels to be used
- Distance to shore, specifically distance to installation ports and O&M ports and power grid tie points, determines vessel days required for installation and maintenance

In Phase 1 of this project the impact of these different factors on levelized costs and project design decisions have been analyzed at a screening level. In Phase 2 of this project, detailed modeling and additional refinement of assumptions will be undertaken. Key Phase 1 conclusions are listed below.

2. General Conclusions

- LC's for repurposed wind projects in the GOM range from \$82 to \$231 per Mwh. Equivalent new build projects have LC's ranging from \$82 to \$437.
- LC's for repurposed hydrogen projects in the GOM range from \$4.76 to \$8.44 per kg of hydrogen. Equivalent new build projects have LC's ranging from \$4.77 to \$19.64.
- While noting that the above LC's do not include any federal or state incentives, these are higher than equivalent low-carbon renewables-based onshore projects, and even more challenged versus high-carbon alternatives.
- However, projects at the lower end of the range of LC's across the GOM have the potential to be competitive with onshore projects through efficient design, cost reductions and use of all available federal and state incentives.
- Of the different components of the oil & gas structure to be repurposed, it is probably most cost-effective to reuse the jacket (main support structure) and the deck (flooring above the structure) for ROICE projects. The remaining equipment will need to be decommissioned as per normal practice - removal of oil & gas topsides, abandonment of all wells and any pipelines that will not be used to transport hydrogen.
- Such repurposing has the dual impact of reducing capex and shortening the schedule of implementation of ROICE projects. Repurposing will have a positive impact on LC for most

projects. This improvement is more pronounced for deeper water projects and for smaller scale projects where the savings from reused infrastructure form a significant portion of the total project capex.

- Shallow water / near-shore locations appear to have the lowest LC for all cases - new build or repurposed, power or hydrogen projects. This is due to several reasons – higher wind speeds, lower structural costs, lower cable costs etc. Repurposing improves the LC by 5 to 10% for these locations.
- Further away from shore, in deeper waters, hydrogen projects and repurposing prove to be more attractive. Hydrogen projects remain relatively attractive as water depth increases, and repurposing can reduce the LC by up to 25% for larger scale projects and up to 60% for smaller scale projects.
- In regions where repurposing has a significant impact, the overall LC is high even with repurposing, indicating challenging project economics. Stronger government incentives and major cost reductions will be needed to make these competitive.

3. Impact of Water Depth and Distance to Shore

- Shallow water / near-shore locations appear to have the lowest LC for all cases - new build or repurposed, power or hydrogen projects. This is due to several reasons – higher wind speeds, lower structural costs, lower cable costs etc.
- Increase in capex for components dependent on depth and distance-to-shore make deeper water / far-from-shore projects more challenging. At these locations, reducing capex outlay via a small-scale hydrogen project or benefitting from economies of scale with a large-scale power project may be the best option.
- Repurposing has a greater impact on power generation projects in deeper water. This can be ascribed to cost-avoidance, through repurposing, of an increasingly expensive new build platform to support the power and hydrogen infrastructure as the water depth increases.
- The costs for repurposed hydrogen projects increase only slightly with water depth beyond water depths greater than ~100m. This is because once the depth-dependent cost of a support equipment platform structure is eliminated through repurposing, the costs of the rest of the hydrogen project components are not dependent on water-depth.
- It is advantageous to consider repurposing options for deeper water / further from shore projects. Of course, these projects are challenged with high LC’s even after repurposing, so further optimization and greater production incentives are needed to make these projects attractive.

4. Impact of Project Size

- Larger projects are a more efficient investment of capital for new build power or hydrogen projects, especially in deeper waters. Shallow water projects are less sensitive to economies of scale.
- Project size has an impact on LC’s for repurposing projects as well, although not as pronounced as in new build projects because of the buffering effect of reusing existing structures.
- Repurposing has a greater impact on smaller projects since the cost of the reused support platform forms a greater fraction of the total capex.
- Reusing pipelines to bring hydrogen back to shore allows for an additional LC impact for smaller hydrogen projects.

- Repurposed hydrogen projects are less sensitive to economies of scale, allowing for smaller capex outlays. Once the cost of the support structure platform is eliminated through repurposing, the other hydrogen project cost components scale in proportion to project size.
- Repurposed power export projects do not have this advantage, since cable costs are more a function of distance to shore, and do not scale with the amount of power being exported.

5. Hydrogen vs. Power Export

- A hydrogen generation project trades off power export cables and an offshore substation for electrolyzers, desalination units and hydrogen pipelines. For new build cases, this tradeoff only results in a ~10% increase in capex for hydrogen export projects over equivalent power export projects.
- Larger scale repurposed cases also incur a similar capex increase vs power projects. For small scale repurposed cases, switching to hydrogen can even result in a 15 to 10% reduction in capex. Note that repurposed hydrogen projects in this study assume that pipelines can be reused to bring hydrogen to shore.
- The incremental economics on the additional capex for hydrogen generation is therefore likely to look quite promising in all cases, especially considering the healthier federal incentives for hydrogen production vs wind power generation.
- Repurposed hydrogen projects in deeper water / further from shore locations have a few advantages over equivalent power projects at these locations. Capex and LC for these locations are not significantly higher than shallow water / near shore locations; reducing the project size to manage capex outlay does not result in a large increase in LC.

6. Optimal Project Options

- Near shore locations are attractive for both wind power export or hydrogen export, over a range of project sizes. Repurposing improves the LC by 5 to 10% for these locations.
- Further away from shore, in deeper waters, hydrogen projects and repurposing prove to be more attractive. Hydrogen projects remain relatively attractive as water depth increases, and repurposing can reduce the LC by up to 25% for larger scale projects and up to 60% for smaller scale projects.
- If a smaller power generation project is planned for deeper waters, repurposing is highly recommended. It can reduce the LC by as much as half for a repurposed project vs a new build one.

B. Future Studies:

In Phase 1 of this study, any federal credits such as ITC or PTC is not applied for renewable energy or 45V for low carbon hydrogen generation since these are likely to be project specific. Further, several broad assumptions have been made to generate LC’s over a large geospatial area. More definitive conclusions are expected to be drawn in Phase 2 where ROICE designs will be developed for specific assets with more accurate cost estimates and include all applicable credits to estimate more accurate project economics.

The work scope for Phase 2 includes:

- Enhance the ROICE LC Model using advanced digital models
- Switch from Levelized Cost concept to project economic metrics such as NPV and Rate of Return

- Conduct sensitivity studies to see which parameters and scenarios have the greatest potential for optimizing and improving project economics
- Develop conceptual ROICE project designs for shortlisted assets using public domain information
- Work closely with ROICE workgroups to cross-implement findings
- Reach out to Operators and plan for collaboration on future phases.
- Refine the asset shortlist to identify potential demonstration and commercial project locations

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