TECHNO-ECONOMIC ASSESSMENT OF GIGAWIND FOR LOW-CARBON POWER SYSTEMS

PREPARED FOR

RADIA

MODELING AND ANALYSIS DATE

Modeling and analysis carried out in March-June 2023

September, 2023

EXECUTIVE SUMMARY

This report carries out an analysis of the **potential role of GigaWind™ technology in the US power system** taking into account the projected cost and operational profile of this new technology. Additionally, the report explored the accelerated impact of GigaWind in light of the passage of the Inflation Reduction Act (IRA) by the US Congress in 2022 over the 2023-2035 and 2036-2050 time periods.

Radia is an energy company and global green energy project developer. Radia is pioneering new technology including GigaWind that represents a step-change in onshore wind energy and its ability to generate more reliable, predictable renewable energy at lower cost and in larger amounts:

> *Radia is an international energy company building a unique, sustainably fueled aerial transportation solution, the WindRunner™, to radically expand the scope and scale of the onshore wind energy industry. Simultaneously, we're developing a world-class portfolio of wind energy projects to leverage this solution. This unique combination of capabilities allows us to bring together the ecosystem of stakeholders and partners to enable GigaWind™: larger onshore wind turbines deployed to more places to deliver green electricity and green molecules at transformational prices. Together, GigaWind and WindRunner will grow the onshore wind energy market by making many new geographies feasible including wind acreage that is inaccessible or uneconomical with existing technology.*
>
> *-Radia Executive Team*

Based on our modeling results, **GigaWind technology presents a revolutionary opportunity for the wind energy market.** The technology **can significantly aid in decarbonization efforts.** The economic viability of GigaWind remains strong, even after the expiration of policy incentives, making it a cost-effective renewable energy source. As the industry addresses supply chain and project development challenges, **GigaWind's impact is expected to be transformative, reducing reliance on fossil fuels and helping achieve a more affordable decarbonized energy mix.**

Our findings are encouraging of the potential value and competitiveness of GigaWind technology from a system point of view. A summary of key findings follows:

1. Potential deployment of GigaWind technology could **reach ~230 GW[1] by 2035 under expected cost and performance** with policy incentives brought by the Inflation Reduction Act (IRA).
2. At this scale, **GigaWind technology could contribute ~20% of total electricity generation by 2035**, playing a crucial role in the decarbonized energy mix.
3. **By 2050, GigaWind could supply 17 - 40% of total U.S. electricity generation** depending on decarbonization targets and level of green hydrogen demand. In a net-zero scenario GigaWind becomes the #1 electricity source under assumed cost and performance projections.
4. **Scaling the supply chain and project development capacity for GigaWind**, will be the **limiting constraint** for GigaWind deployment until 2035, not project economics. We find it is profitable to deploy even more GigaWind by 2035 if the industry can scale up faster than modeled growth rate constraints.
5. Extending current incentives established by IRA through 2050 would induce an additional 230 GW post-2035 deployment, while **targeting net-zero power sector emissions by 2050 would push GigaWind deployment post-2035 to 500 GW.**
6. Availability of **GigaWind lowers total system cost by $9B-yr in 2035 and by $8B-yr to $15B-yr in 2050** across scenarios due to added system value and lower capital cost and operating cost per MW installed.
7. Improved operational profile of **GigaWind helps lower carbon emissions by 15% in 2035 and by 16-31% in 2050 depending on the scenario** for scenarios without strict carbon constraints (i.e., no Net-Zero policy).
8. Introduction of **GigaWind lowered electricity prices in 2035 by 5%** due to cost savings in total capital deployment and avoided fossil fuel costs driven by high capacity factors and by **5% to 16% in 2050**.
9. **GigaWind displaces both conventional onshore wind as well as reduces the need for new natural gas generators**. **Gas-fired capacity declines by 60% in 2035 when GigaWind is available** and GigaWind also slightly reduces the need for new solar PV (5%) and storage (7%), while driving a 30% decline in deployment for conventional onshore wind.
10. **GigaWind remains the most competitive source of renewable energy available, even after the scheduled expiration of IRA incentives. Thus, higher natural gas prices post-2035 could lead to an additional deployment of 200 GW** of GigaWind by 2050.

[1] Maximum volume under assumed supply-chain constraints

11. **Constrained transmission build-up has limited impact on GigaWind** deployment by 2035, but does affect standard wind by reducing deployment by 12%. GigaWind's ability to operate in lower wind speed regions and thus closer to load, minimizing transmission requirements.
12. Additional demand for electricity to produce 'green' hydrogen via electrolysis expands the market opportunity for GigaWind. In a net-zero scenario, GigaWind deployment between 2035 and 2050 **increases from 500 GW to 650 GW due to increased electricity demand for green hydrogen production**.

About DeSolve LLC

DeSolve LLC is a consulting firm providing expertise in energy systems and decision support for investors, technology ventures, and other clients working to accelerate the deployment of clean energy solutions. Founded by Dr. Jesse Jenkins and Dr. Nestor Sepulveda, DeSolve was started by the pair after meeting at the Massachusetts Institute of Technology (MIT), where they worked together to develop state-of-art decision support tools and methods to understand complex energy systems, including the GenX electricity system optimization model[2], now in wide use at both Princeton and MIT and available as an open source software tool. Past DeSolve clients include the OECD, Form Energy, the Environmental Defense Fund, Clean Energy Task Force, Westinghouse, CorPower Ocean, JP Morgan, NetPower, Radia, Eavor Technologies, and Grid United.

Jesse is an assistant professor and macro-scale energy systems engineer at Princeton University. He earned PhD and SM degrees from MIT, worked previously as a postdoctoral fellow at Harvard, and has 17 years of experience in energy systems and energy policy. Nestor works in corporate strategy, technology development, decarbonization, and sustainable investing. Nestor earned a PhD from MITdeveloping methodologies that combine operations research and analytics to guide the energy transition and cleantech development. He also received a SM in Technology and Policy working on energy policy and economics and a SM in Nuclear Science and Engineering, both from MIT.

Dr. Jenkins and Dr. Sepulveda have both provided expert input to federal and state policy makers, including delivering invited testimony to Congressional committees or during expert meetings on energy transition topics. Their work has been featured in major media outlets including the *New York Times*, *Wall Street Journal*, *Washington Post*, *The Economist* and other major media outlets.

Since 2018, the pair has published extensively on the role of firm low-carbon resources[3], completed the first system-level analysis of 24/7 carbon-free electricity

[2] https://energy.mit.edu/genx/
[3] Baik et. al. 2021, What is different about different net-zero carbon electricity systems?

procurement[4], and frequently employed GenX to assess the role and value of nascent clean energy technologies both in peer-reviewed academic publications[5] cited hundreds of times[6] and as consulting engagements for early-stage technology ventures.

Macro-energy systems modeling overview

Why not Levelized Cost of Electricity?

The use of "Levelized Cost of Electricity" (LCOE) as a metric for evaluating technology competitiveness has become common, but it has notable limitations. LCOE calculates the average electricity price required to recover costs over a generation asset's lifetime based on specific assumptions. However, LCOE fails to account for broader system dynamics and interactions. It ignores changes in technology deployment over time and the impact of other technologies. Operational constraints and costs associated with intermittency are also disregarded, along with the varying value of energy produced at different times. For instance, energy produced during peak demand holds different value. Furthermore, LCOE overlooks cycling costs due to ramping and startup/shutdown of other generation assets. While LCOE can be useful for standalone investment analysis, it inadequately informs system-wide policy decisions, investment planning, or market valuation. To address this, more sophisticated methods are needed that consider both cost and value in dynamic energy systems. System models that optimize investment decisions while accounting for hourly system operation offer a better approach. These models capture complex trade-offs and interactions between technologies, offering a comprehensive perspective for policy-making and investment planning in evolving energy landscapes. This approach is recognized as the gold standard by policy makers and investors seeking to navigate the energy transition effectively.

System modeling approach

This modeling work was performed using GenX, an open-source state-of-the-art electricity system capacity expansion planning model. Originally developed at the Massachusetts Institute of Technology by DeSolve co-founders Dr. Jesse D. Jenkins & Dr. Nestor Sepulveda and now actively maintained by researchers at MIT and Princeton University, GenX is a highly configurable optimization-based tool designed for investment planning and decision support for a changing electricity landscape. GenX takes the perspective of a centralized planner or an efficient, competitive market to co-optimize the least-cost portfolio of electricity generation, energy storage, and transmission investments needed to meet a predefined electricity demand at hourly

[4] https://acee.princeton.edu/24-7/
[5] The design space for long-duration energy storage in decarbonized power systems https://www.nature.com/articles/s41560-021-00796-8
[6] https://scholar.google.com/scholar?cites=13198352940419635972

resolution, while adhering to various technological and physical grid operation constraints, resource availability limits, and other imposed environmental, market design, and policy constraints. GenX has been used widely in a wide range of peer-reviewed publications, major reports, and in DeSolve's consulting practice.

Data for this study was compiled using the open-sourced power system data and scenario compiler, PowerGenome. In this study, GenX is configured to model 26 zones across the continental United States with explicit transmission network constraints between zones based on an aggregation of EPA Integrated Planning Model zones. Existing generator data is based on EIA Form 860. Cost assumptions for new resource options are from NREL *Annual Technology Baseline 2022* with regional cost multipliers based on EIA's Electricity Market Module (2020 edition). Wind and solar candidate project areas (4km x 4 km) are derived from geospatial analysis performed by the REPEAT Project, with additional data on Gigawind performance provided by Radia. Hourly demand time series are based on per unit profiles from the NREL *Electrification Futures Study* with total demand scaled to reflect EIA Annual Energy Outlook (AEO) reference scenario + electric vehicle & heating electrification assumptions derived from REPEAT Project scenarios (Current Policies (mid-range) for current policy scenario and Net-Zero Pathway for zero-carbon scenarios). Zonal demand for electrolysis in hydrogen demand sensitivity cases are also derived from REPEAT Project. Fuel cost assumptions are from EIA AEO (reference scenario for all cases except high gas price case, which uses fuel prices from AEO's low oil & gas availability scenario). We model all state RPS and CES policies and major state resource procurement mandates (e.g. offshore wind procurements) and NERC capacity reserve planning margins for each region (except Texas ERCOT which is modeled as an energy-only market with no planning reserve constraint).

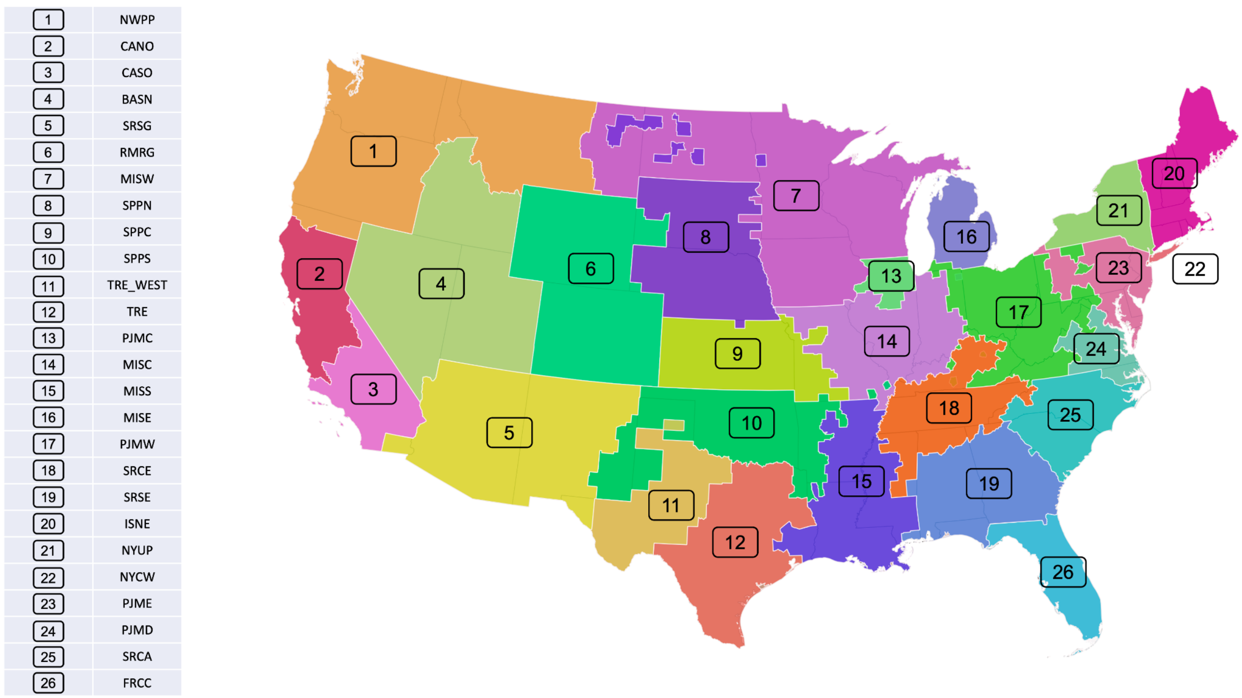

Figure 1. GenX model regions for this study

GenX is run in a sequential mode for this study, planning first for capacity expansion and retirement decisions to meet expected demand in 2035 and then with results from 2035 used as the starting point for expansion to 2050. For each planning period, we model a full year of 52 weeks with sequential hourly operations, subject to detailed operating constraints, including unit commitment decisions and ramp rate constraints for thermal power plants, sequential operation of energy storage devices, endogenous optimization of renewables curtailment, etc. Capacity investment and retirement decisions for all generators, energy storage, and inter-regional transmission expansion along with hourly operational decisions are co-optimized by the model to produce the least cost approach to meet projected future demand subject to constraints on system reliability, market clearing, and state policy. In hydrogen sensitivity cases, we also explicitly model optimal electrolyzer capacity investment and operations to meet required hydrogen demand in each zone.

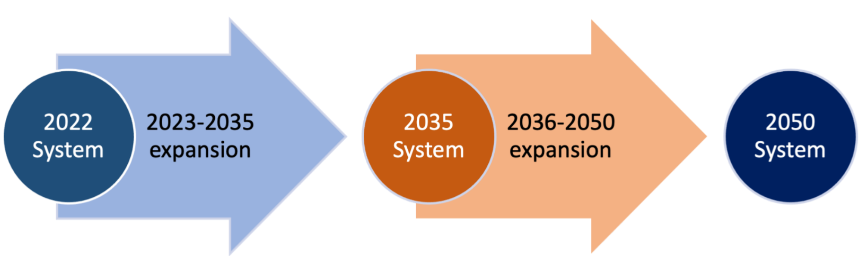

Figure 2. Sequential modeling used for this study

Assessment of GigaWind deployment in the US

Overall system modeling setup

All modeled scenarios incorporate current policy measures including state Renewable Portfolio Standard and Clean Electricity Standard policies, key state resource procurement mandates (e.g. for offshore wind), and federal tax incentives established or modified by the Inflation Reduction Act of 2022 (IRA). Electricity related incentives established by IRA include: a) an investment tax credit (ITC) for new carbon-free electricity generation and energy storage, equal to 30% of the project's investment cost, assumed to be elected by nuclear and offshore wind projects, b) a production tax credit (PTC) for new carbon-free electricity generation equal to $26 per MWh (in 2022 dollars,escalating with inflation) over the first decade of operations, assumed to be elected by onshore wind and solar PV, and c) a tax credit for CO2 capture and sequestration (45Q) equal to $85 per ton of sequestered CO2 over the first twelve years of operations available to new natural gas power plants with CCS. In all scenarios, these federal tax incentives are assumed to be available to qualifying projects coming online before the end of 2035, as per current statute. For the 2036-2050 model period, we consider several possible future scenarios, including: (1) expiration of current federal incentives; (2) continuation of current federal incentives through 2050; and (3) replacement of current federal incentives with a binding emissions limit reaching zero emissions by 2050.

Scenario design

In order to comprehensively assess the economic implications and potential systemic impacts of GigaWind, we conducted an evaluation comprising a range of base scenarios spanning the years 2035 and 2050, along with several sensitivity analyses. The base scenarios encompassed diverse scenarios, each exploring different decarbonization targets and underlying support mechanisms:

- **Current IRA incentives, with and without GigaWind:** a set of cases that toggles the ability to deploy Radia's technology and reflects a conservative market outlook under current IRA incentives and expiration timeline.
- **Extended IRA incentives, with and without GigaWind:** a set of cases for the expansion of the system that toggles the ability to deploy Radia's technology and reflects an intermediate market outlook where current IRA incentives are extended until 2050. This scenario simulates continued policy support beyond 2035 after the IRA expires.

- **Net-Zero policy, with and without GigaWind:** a set of cases for the expansion of the system that toggles the ability to deploy Radia's technology under current IRA incentives and an additional Net-Zero mandate by 2050, creating the most optimistic market opportunity for GigaWind.

In addition to the base scenarios, we conducted sensitivity analyses that further enriched the assessment:

- **Constrained network expansion:** analysis of the impact on the system transformation by constraining expansion of the transmission network to 1.5% /yr versus unconstrained expansion in the base scenarios.

- **Hydrogen economy:** analysis of the impact of increased demand for electricity to produce electrolytic hydrogen on the deployment of GigaWind. We use regional electrolytic hydrogen demand requirements from REPEAT Project (Current Policies for 2035 and either Current Policies of Net-Zero Pathway scenarios for 2050, depending on the policy case); requiring the specified level of annual hydrogen production in each zone via optimized electrolysis capacity and operations decisions for the base Current IRA (8 GT of green H2 demand in 2035 and 9 GT in 2050) and Net-Zero policy scenarios (8 GT of green H2 demand in 2035 and 31 GT in 2050).

- **High gas prices:** analysis of the impact of higher natural gas prices on the system transformation between 2035 and 2050. U.S. average natural gas prices are assumed to increase from around $4 per mmBTU to $6 per mmBTU while maintaining a consistent regional variation in prices (some regions are higher and others are lower than average).

Collectively, the scenarios and sensitivities shown in Table 1 offer a robust framework to comprehend the implications of GigaWind technology within various future potential economic and policy landscapes.

Table 1. Scenarios and sensitivities (all run with and without GigaWind)

Scenario	Description	Key Assumptions for 2035	Key Assumptions for 2050
Current IRA Incentives scenario	Conservative market opportunity cases	IRA incentives	IRA incentives expired, no further support
Extended IRA Incentives scenario	Intermediate market opportunity cases	IRA incentives	IRA incentives extended until 2050 at current levels

Net-Zero Policy scenario	Optimistic market opportunity cases	IRA incentives	Net-zero emissions constraint in 2050
Constrained Network Expansion sensitivity	Constrained transmission network expansion variants of Current IRA and Net-Zero scenarios	Expansion limited to 1.5%/yr from 2022 levels	Expansion limited to 1.5%/yr from 2035 levels
Hydrogen Economy sensitivity	Impact of electrolytic hydrogen demand due to increased demand for electricity in Current IRA and Net-Zero scenarios	8 GT of green hydrogen required outside of the power system	9/31 GT of green hydrogen required outside of the power system for Current IRA/Net-Zero Policy scenarios
High Gas Prices sensitivity	Impact on system transformation due to higher gas prices post 2035	Same as base scenarios	US average natural gas price increases from around $4 per mmBTU in base scenarios to $6 per mmBTU

Results and key takeaways

Potential deployment of GigaWind technology could reach ~230 GW by 2035 under expected cost and performance with policy incentives brought by the Inflation Reduction Act (IRA)

Figure 3, depicts the 2023-2035 cumulative new capacity deployments and the 2035 final capacity mix under the IRA incentives modeled. When GigaWind is available to be deployed, 230 GW[7] of total GigaWind capacity would be built by 2035 in the least cost capacity mix. This projection is founded upon the anticipated cost-effectiveness and optimized performance of the technology, further propelled by the policy incentives established by the IRA. The figure shows how GigaWind reduces deployment of conventional wind while also increasing the wind share in the mix and moving the system from solar dominated to wind dominated generation.

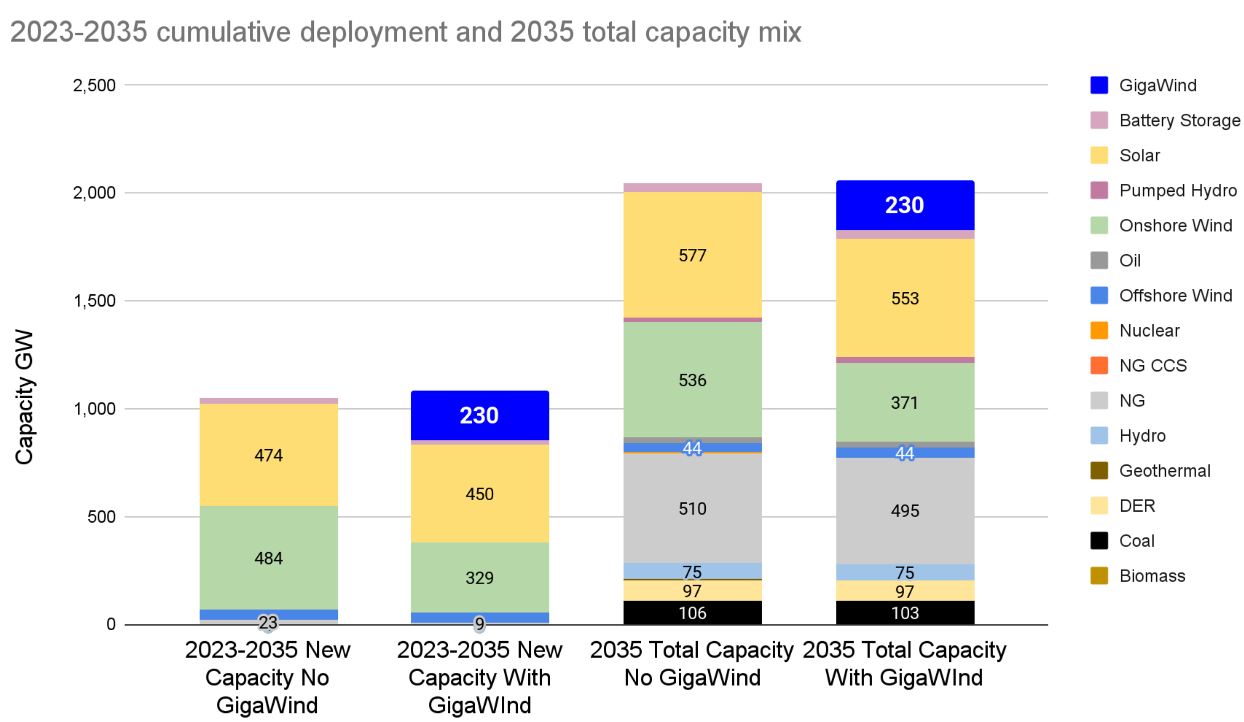

Figure 3. 2023-2035 cumulative new deployments and 2035 final capacity mix

[7] Maximum volume under assumed supply-chain constraints

The rate at which the supply chain and project development capacity for GigaWind can scale will be the limiting constraint for GigaWind deployment until 2035, not project economics. We find it is profitable to deploy even more GigaWind by 2035 if the industry can scale up faster than modeled growth rate constraints.

In our baseline scenarios, GigaWind cumulative 2023-2035 deployment is restricted to 230 GW by what Radia has identified as a limiting constraint. Figure 4 provides a visual representation of GigaWind deployments from 2023 to 2035 in an unconstrained scenario, where it reaches 590 GW based on cost and performance projections from Radia. However, this deployment faces constraints stemming from anticipated supply chain bottlenecks. These bottlenecks are a result of both expected production limitations, assumed to be 65% of the standard onshore wind capacity deployment in the absence of GigaWind, as the technology scales up, and anticipated restrictions on the capacity available to operate the WindRunner aircraft, which is crucial for transporting components from production to their intended destinations.

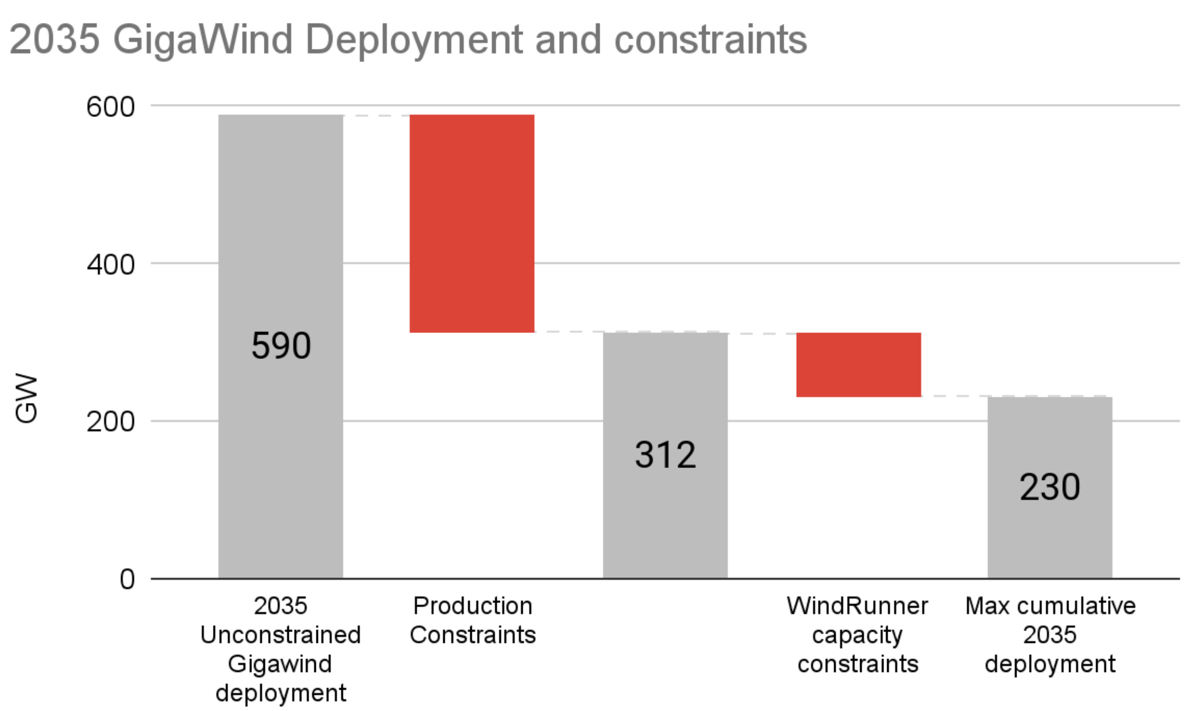

Figure 4. 2023-2035 GIgaWind potential deployment and constraints

Extending IRA incentives through 2050 would induce an additional 230 GW post-2035 deployment and targeting net-zero power sector emissions by 2050 would push GigaWind deployment from 2035-2050 to 500 GW.

As shown in Figure 5, the trajectory of GigaWind deployment beyond 2035 hinges on assumptions regarding sustained policy support for decarbonization. If we extend the IRA incentives as an indicator of continued decarbonization support through 2050, we anticipate additional GigaWind deployment to align with the deployment projected for the 2023-2035 period, resulting in a cumulative GigaWind deployment of 460 GW from 2023 to 2050. However, if we intensify decarbonization efforts to achieve net-zero emissions in the entire U.S. power sector by 2050, the demand for GigaWind surges, accelerating deployment between 2035 and 2050 and increasing the total GigaWind deployment to 720 GW by 2050. In an unlikely scenario where no additional decarbonization measures are taken, GigaWind's deployment after 2035 continues at a more modest pace, with approximately 50 GW of additional deployment.

Figure 5. Cumulative new GigaWind capacity deployed over time under different scenarios

GigaWind remains the most competitive source of renewable energy available, even after the scheduled expiration of the IRA, and an increase in gas prices post-2035 could lead to an additional deployment of 200 GW of GigaWind by 2050.

Even if there's no further policy support for renewable energy post-2035, Figure 5 presents an intriguing scenario in the High Gas sensitivity setting, where gas prices climb from around $4 per MMBTU to $6 per MMBTU. In this scenario, we witness the deployment of approximately 200 GW of GigaWind between 2035 and 2050. This remarkable surge in GigaWind deployment, driven by the rising gas prices, underscores its pivotal role in the energy landscape. This growth can be attributed to GigaWind's exceptional capacity factors and cost-effectiveness, enabling it to substitute for firm generation sources and reduce a significant portion of gas-fired generation.

Turning to Figure 6, it offers a visual comparison of new capacity deployments between 2035 and 2050, considering the expiration of IRA incentives and elevated gas prices. Notably, GigaWind emerges as the technology with the most substantial growth, bridging the gap left by reduced new natural gas generation capacity. These findings emphasize the value of deploying more GigaWind as a safeguard against potential natural gas price spikes. Furthermore, the absence of flexibility from natural gas under the High Gas sensitivity prompts an additional 20 GW deployment of conventional wind, driven by increased operational synergies.

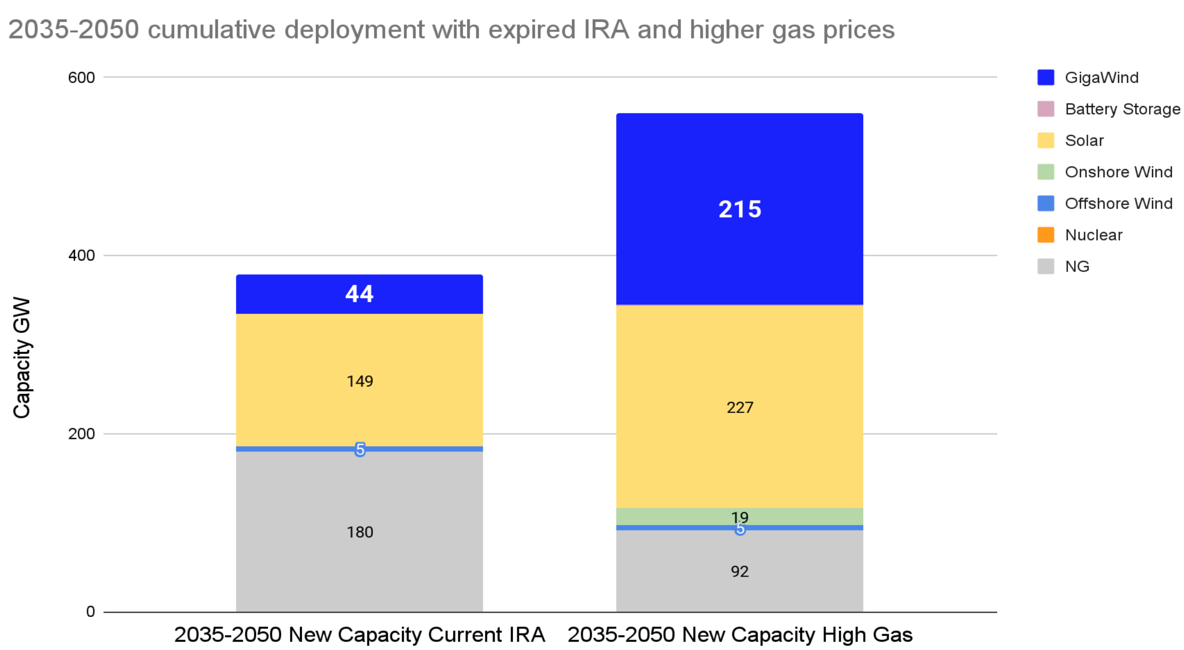

Figure 6. 2035-2050 new capacity deployments with expired IRA incentives and under higher gas prices

Availability of GigaWind lowers total system cost by $9B-yr in 2035 and by $8B-yr to $15B-yr in 2050 across scenarios due to added system value

Figure 7 compares the annualized total system cost, or the total cost of bulk electricity supply — i.e., yearly opex plus annualized cost of investment and fixed O&M in the final year of each planning period, 2035 and 2050 — across scenarios. The figure also shows the percentage reduction in total system cost for each scenario when GigaWind becomes an available technology. This system's savings show GigaWind´s system value far outweighs its cost. System value of GigaWind is dependent on other technologies in the mix and the operational constraints in the system. As such, system cost reductions vary by scenario from $9B-yr and $8B-yr in the 2023-35 and 2035-2050 periods respectively under existing IRA incentives, to $15B-yr under extended IRA incentives, and $26B-yr in a net-zero scenario.

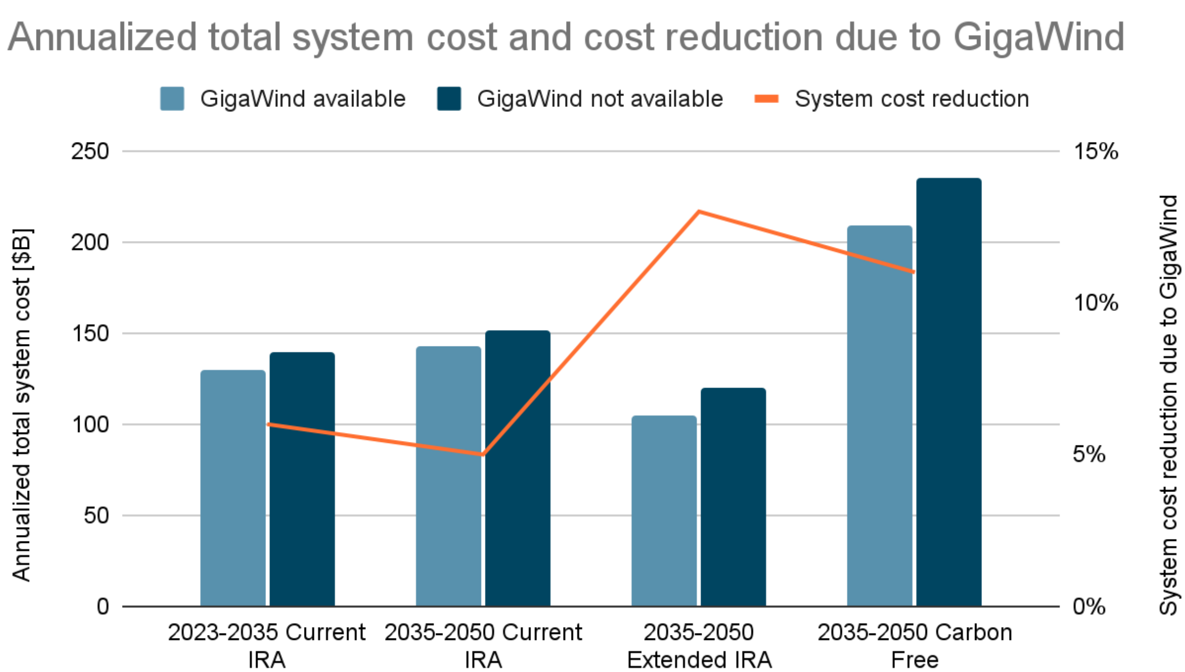

Figure 7. Annualized total system cost (investments plus operation) under different scenarios and impact of adding GigaWind

Improved operational profile of GigaWind helps lower carbon emissions by 15% in 2035 and by 16-31% in 2050 depending on the scenario for scenarios without strict carbon constraints (i.e., no Net-Zero policy)

Figure 8 presents a comparison of total carbon emissions in the power system across different scenarios that do not incorporate a Net-Zero approach, displayed on an annualized basis. Additionally, the figure illustrates the percentage reduction in total carbon emissions for each scenario upon the introduction of GigaWind technology. These reductions in emissions highlight the superior operational performance of GigaWind in comparison to other renewable energy sources. Importantly, GigaWind's efficiency reduces the necessity for flexibility from fossil-fueled generation, and these reductions are achieved without the need for additional carbon restrictions or incentives. Consequently, the degree of emissions reduction varies by scenario: a 15% decrease in emissions is observed during the 2023-2035 period when GigaWind becomes available, a 16% decrease under current policies in the 2035-2050 period, and a remarkable 31% reduction under extended IRA incentives in the same 2035-2050 period.

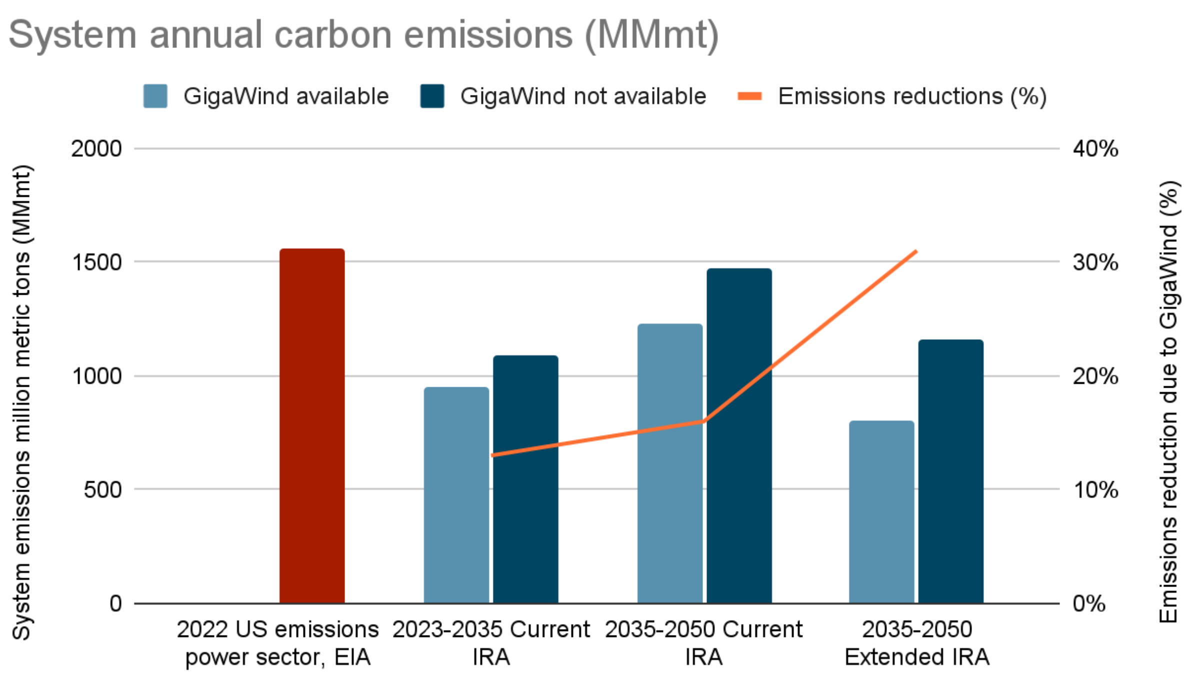

Figure 8. Yearly power system emissions under different scenarios and impact of adding GigaWind

Introduction of GigaWind lowers average electricity price in 2035 by 4% and by 5% to 16% in 2050 due to increased penetration of renewable energy and increased hours with renewables as marginal resource

Figure 9 shows the average price of electricity across scenarios and its change when GigaWind becomes available for deployment. When GigaWind is available for deployment the average price of electricity in the system goes down across all scenarios. This is due to increased penetration of renewables in the system and an increased number of hours with renewable energy as the marginal resource thanks to GigaWind expected cost and performance.

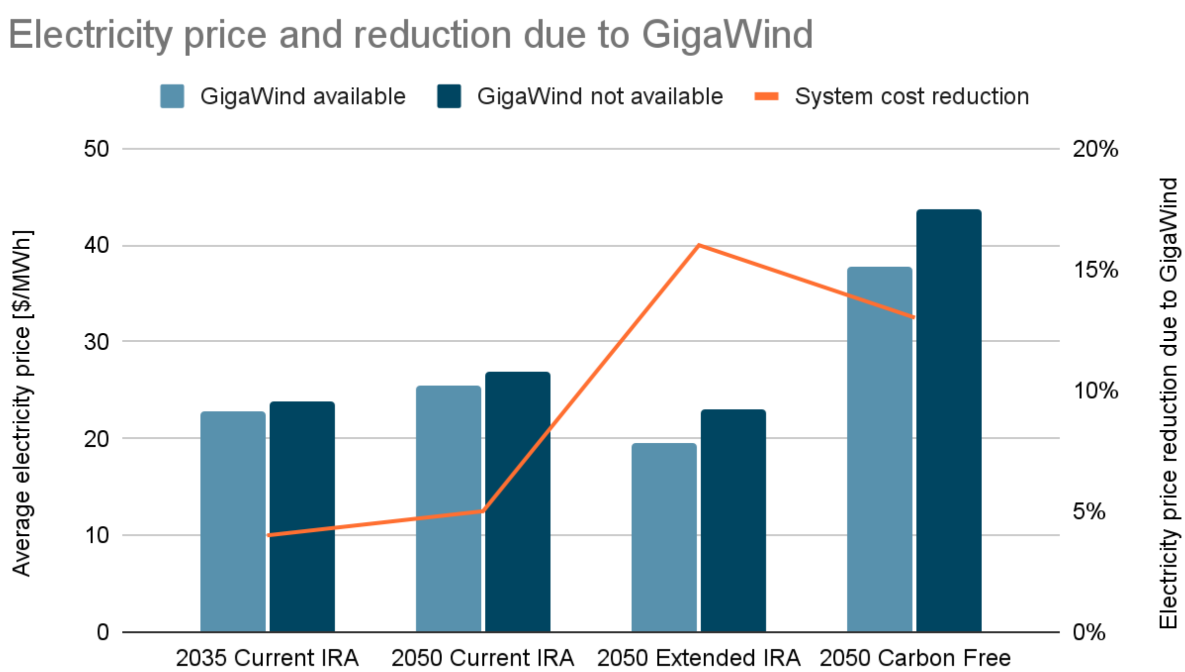

Figure 9. US average electricity price under different scenarios and impact of adding GigaWind

By 2035, GigaWind technology could contribute ~20% of total electricity generation, playing a crucial role in the decarbonized energy mix.

Figure 10 shows the resulting energy mix — i.e., percentage contribution to total supplied demand — by resource for 2035 with and without GigaWind available. As shown in the figure, when GigaWind is available around 20% of total supplied demand is served by the technology. A majority of the energy being supplied by GigaWind replaces energy that otherwise would have been supplied by conventional onshore wind and solar power. However, around a quarter of the energy supplied by GigaWind displaces the use of fossil-fueled generation by reducing the energy shares of natural gas and coal in the system. This translates into further emission reductions and higher share of clean energy due to the availability of GigaWind.

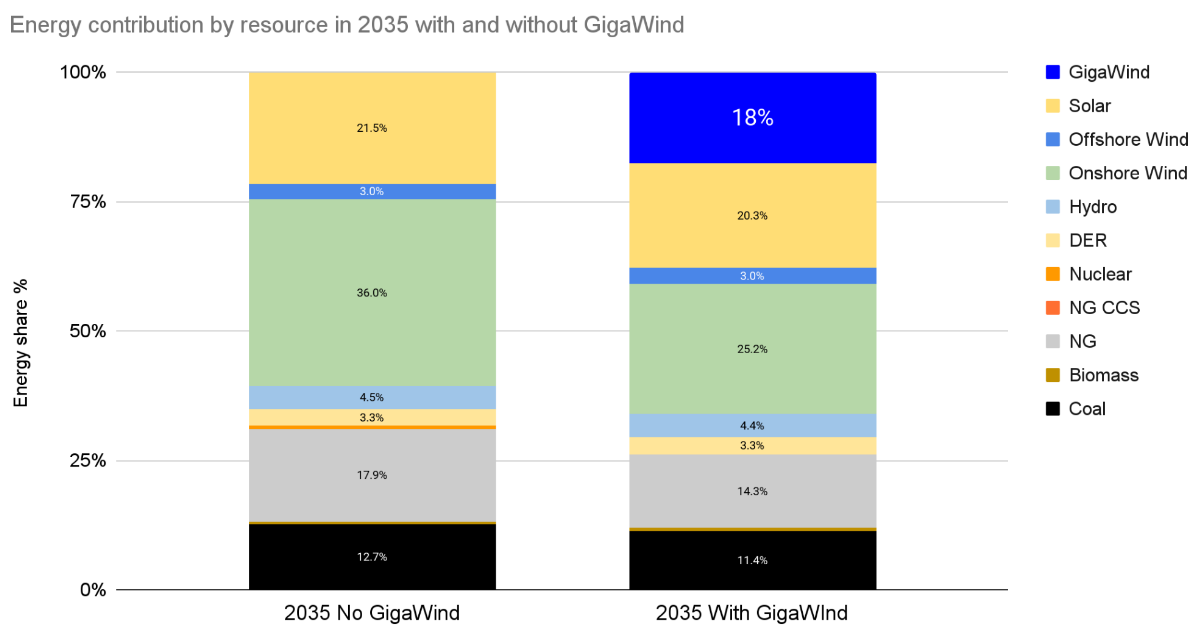

Figure 10. 2035 energy shares by resources with and without GigaWind availability

By 2050, GigaWind could supply 17-40% of total U.S. electricity generation depending on decarbonization targets and level of green hydrogen demand

Figure 11 shows the resulting energy mix by resource for 2050 with and without GigaWind available under the different policy support scenarios. Despite expired IRA incentives, GigaWind continues to serve around 20% of demand through 2050 under the Current IRA scenario. However, extended policy support greatly increases the role of GigaWind in 2050, pushing the energy share to 30% and making the technology the #1 electricity source in the United States. Around a third of GigaWind's energy further displaces fossil fuels in this scenario by reducing generation from coal and natural gas plants. In the event of a net-zero policy, GigaWind's energy share increases further to 40% and the technology sees uncontested dominance in U.S. electricity supply, even reducing the need for natural gas with carbon capture and sequestration by around half.

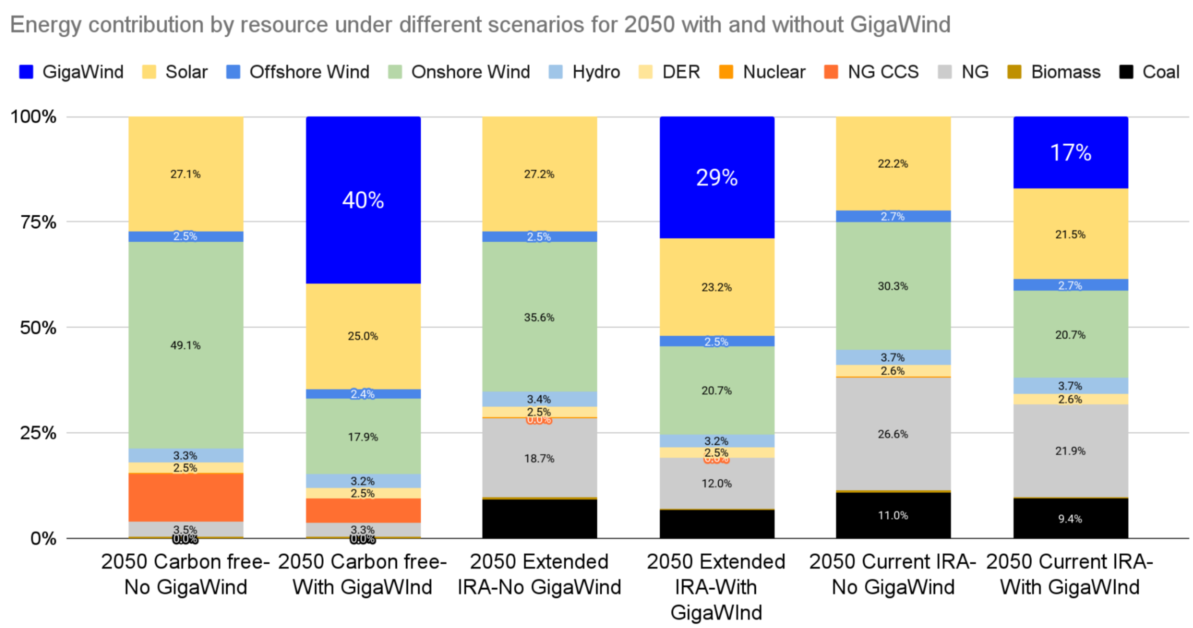

Figure 11. 2050 energy shares by resources with and without GigaWind availability

GigaWind displaces both conventional onshore wind as well as reduces the need for new natural gas generators. Gas-fired capacity declines by 60% in 2035 when GigaWind is available and GigaWind also slightly reduces the need for new solar PV (5%) and storage (7%), while driving a 30% decline in deployment for conventional onshore wind when GigaWind is available.

Figure 12 shows changes in the 2035 capacity mix by making GigaWind available. As shown in Figure 3, 230 GW of GigaWind will be deployed in 2035 when available. This GigaWind capacity displaces a number of resources in the system starting with 62% reduction in new gas-fired combustion turbine capacity compared to the case without GigaWind. Conventional onshore wind is reduced by 32% also showing the biggest absolute capacity reduction with 154 GW of capacity replaced by GigaWind. This makes conventional onshore wind and GigaWind direct competitors and substitutes. Additionally, GigaWind reduces the need for storage capacity by 7% and substitutes a small share of solar generation (5%) due to high capacity factor and improved operational profile.

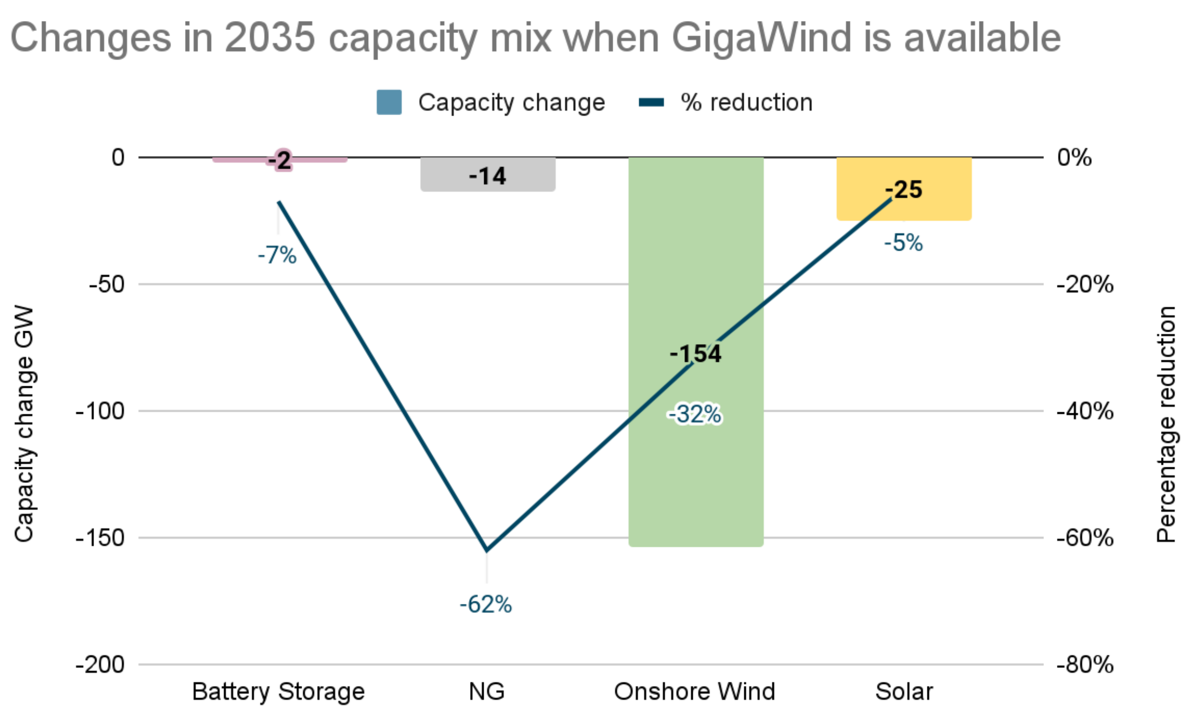

Figure 12. 2035 capacity mix changes due to GigaWind becoming available

Constrained transmission build-up has limited impact on GigaWind deployment by 2035, while reducing deployment of standard onshore wind by 12%.

Figure 13 shows the impact of imposing constraints on the pace of transmission expansion (limited to 1.5%/year increase in capacity). Under constrained network expansion, GigaWind capacity remains unchanged while conventional onshore wind is reduced by 12% due to higher dependency on sites that are further away from load centers. Solar, gas-fired turbines, and battery storage increase in the system due to their ability to be deployed closer to load. No additional GigaWind is observed since in 2035 it has already reached its maximum deployment capacity as shown in Figure 4.

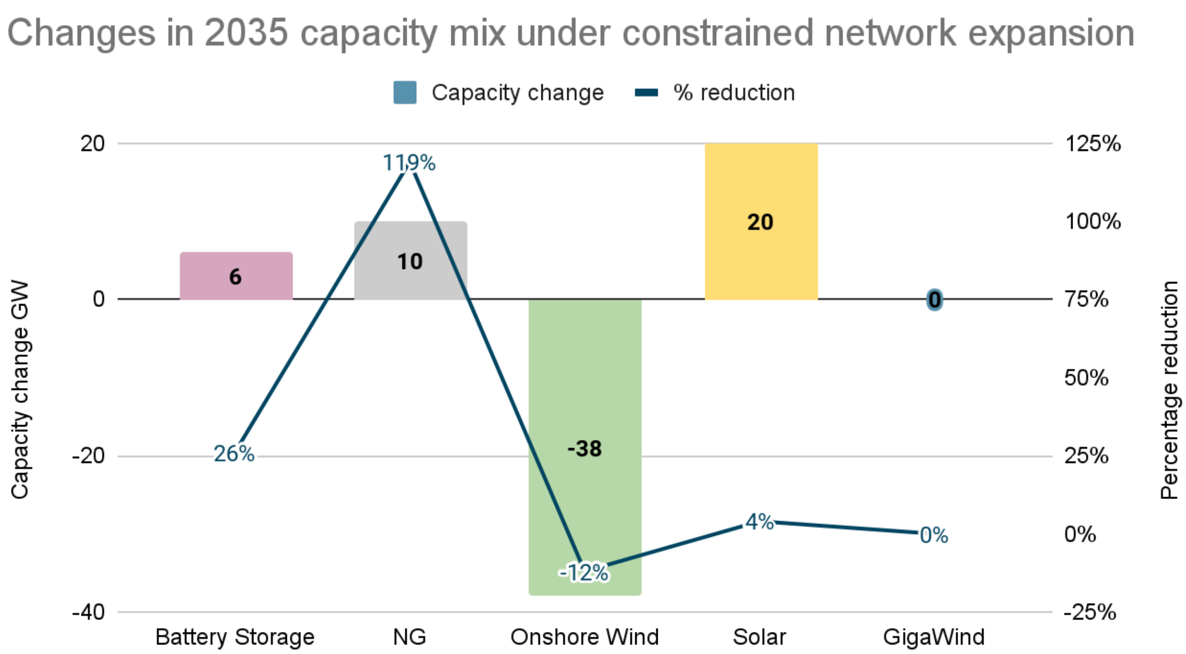

Figure 13. 2035 capacity mix changes due to imposing network expansion constraints in scenario with GigaWind available

Additional demand for electricity to produce ‘green’ hydrogen expands the market opportunity for GigaWind. In a net-zero scenario, GigaWind deployment post-2035 increases from 500 GW to 650 GW due to increased electricity demand for green H2 production.

In the 2050 Net-Zero scenario under the Hydrogen Economy sensitivity the system must supply 31 gigatons of green hydrogen annually. This green hydrogen is produced by economical deployment and operation of electrolyzers across the different regions to supply their local demands. Figure 14 shows the impact of the increased electricity demand coming from electrolyzers’ operation on the 2050 capacity mix. As seen in the figure, green hydrogen production creates system flexibility on the demand side reducing the need for flexibility on the supply side; thus reducing battery storage, combustion turbine (running on clean H2 in 2050), and fossil-fueled turbines with carbon capture and sequestration. At the same time, the increased demand for clean electricity creates a substantial additional market opportunity for renewables, driving an increase of around 150 GW for GigaWind deployment while at the same time increasing the need for solar (160 GW) and conventional onshore wind (80 GW).

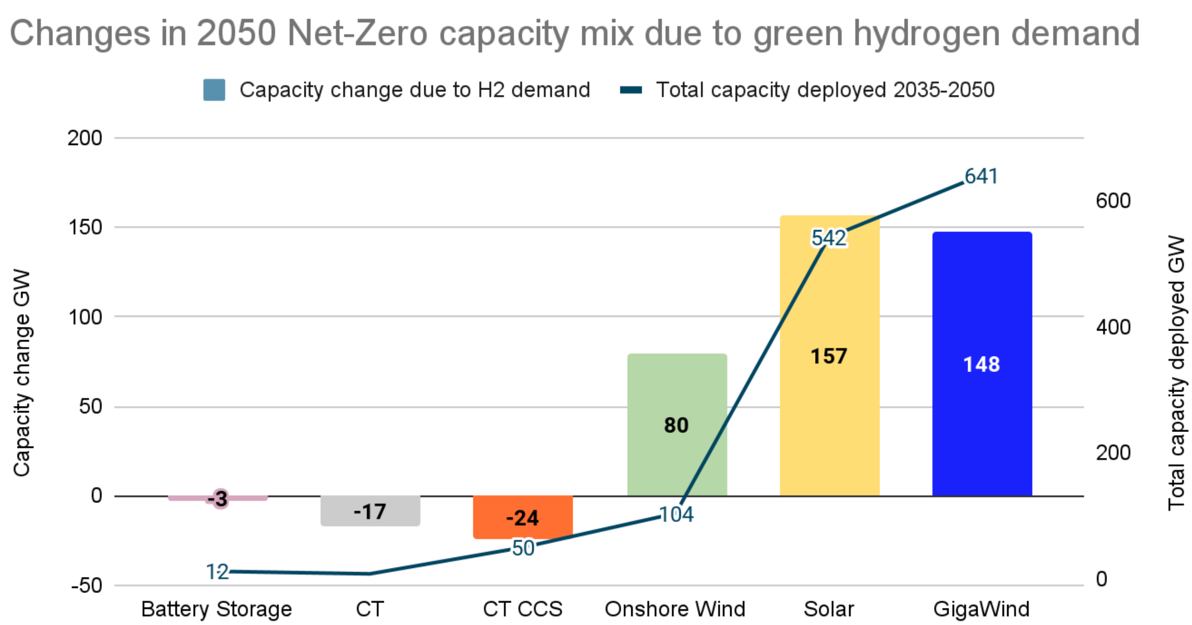

Figure 14. 2050 capacity mix changes in Net-Zero scenario due to green hydrogen electricity demand when GigaWind is available

A note on interpretation of modeled results

Optimization modeling used in this work assumes rational economic behavior from all actors. The modeling also has limited ‘frictions’ on deployment of infrastructure (e.g., power generation or transmission capacity), scale-up of industry supply chains (e.g., wind and solar), or consumer adoption of alternative products (e.g., EVs, heat pumps).

Real world outcomes will contend with various non-cost related challenges that may slow the pace of change relative to modeled results.

Modeling results should thus be interpreted as indications of the relative alignment of economic incentives.

In other words, these results indicate what decisions make good economic sense for consumers and businesses to make. This is likely a necessary condition, but whether or not actors make such decisions in the real world depends on many factors we are unable to model.

Additionally, modeled outcomes reflect a least-cost optimization process. There are likely many alternative outcomes with near-optimal costs (e.g., similar costs within a few percent of these outcomes) which may offer advantages in terms of other important outcomes related to the distribution of costs and benefits associated with energy systems. Various stakeholders may prefer one or more of these alternative portfolios to the outcomes presented herein.

Readers should interpret modeled results accordingly.

Appendix

GigaWind cost and performance inputs from RADIA

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Summary

Radia provided DeSolve with wind turbine net capacity factor for each hour of an average representative year for each of the geographical points provided by DeSolve. The net capacity factor profiles were provided both for a 'standard wind' technology and for Radia's GigaWind technology.

In addition, Radia also provided both overnight capital cost (in $/kW) and average yearly operating costs ($/kW/Yr) for installed standard and GigaWind capacities.

The following sections outline Radia's internal and jointly developed techno-economic modeling capabilities, approach, and assumptions for these deliverables.

Basis of Estimate

The basis of the estimate described herein will provide details of cost models, financial assumptions, and various energy generation related assumptions.

Each wind farm is assumed to produce power and generate revenue for 30 years after commercial operation date (COD).

Cost Modeling

This section describes both capital and operating cost models and results for the wind technologies.

Capital Costs

Radia's internal capital cost models have been developed in conjunction with NREL, DNV, Fichtner Engineering and Consultants, and CREADIS. They have also been augmented with and calibrated against two-way data exchanges with many of the world's top wind turbine OEMs.

The wind turbine machine costs come from component-level "bottoms-up" estimates for each of the major turbine components: tower, blade, hub, blade pitch system, rotor yaw system, main bearing, hvac system, generator, high and low speed shafts, gearbox, bedplate frame, and nacelle cover. These component weights and costs are assumed to be a function of the turbine nameplate capacity and rotor diameter and have many regression data points to yield distributions of these parameters.

In order to capture the impact of future learning and attendant cost reductions on the wind energy technology, NREL's Advanced Technology Baseline (ATB) is used to scale down costs from today's estimates. The 'moderate' outlook is employed in this scenario.

For capital costs of the wind installation that are not related to the wind turbines themselves, NREL's LandBOSse is used as a foundation to estimate the costs for:

- Turbine erection
- Civil works (roads, clearing)
- Electrical collection (trenched cabling)

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- Substation and regional interconnect spur line
- Turbine foundation and installation
- Development costs, fees, and management costs

The LandBOSse models have been augmented in some areas to align with expected trends for wind farms that have fewer, larger, more powerful wind turbines. Additionally, to accommodate the aerial delivery of the wind turbine blades, semi-prepared runway costs are also estimated using both internal Radia models and expert consultant input for additional civil works costs.

For the standard wind technology, ground transportation is estimated for each component, for a nominal distance that is indicative of the United States geographies. The components are transported in the form of blades, hubs, tower sections, drivetrains, and nacelles.

For the GigaWind wind turbine blades, detailed aerospace engineering performance simulations inform the fuel, maintenance, crew, insurance, and depreciation costs to transport the blades by air.

Finally, once the full wind farm capex has been computed, an additional 3% contingency is applied.

Yearly Operating Costs

Radia operating costs models have been developed with Fichtner Associates with added refinement related to U.S. land acquisition and lease rates for private and public lands.

Each year, the costs to operate the wind facilities include the following items:

- Operations and Maintenance contract (includes 10% escalation every 5 years for the duration of the wind farm lifetime)
- Wind plant maintenance and management
- Substation maintenance and management
- Land leases (includes 2% per year escalation)
- Insurance

Wind Turbine Technology

The specifications and design parameters used for the wind technologies modeled for the DeSolve study are provided in Table 1. The capacity is optimized specifically for each location to minimize LCOE, and the bounds allowed were 180 to 320 W/m2. All GigaWind turbines used a 104m blade, which yields a 212m rotor diameter with a hub diameter of approximately 4m. The remaining parameters for both standard and GigaWind turbines are provided in Table 1.

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Table 1: Wind turbine specific parameters.

		Standard Wind	GigaWind
Nameplate Capacity	MW	4.5	<optimized uniquely for each point>
Rotor Diameter	m	150	212
Hub Height	m	100	140
Max Power Coefficient		0.49	0.49
Max Tip Speed	m/s	88.0	90.0
Optimum Tip Speed Ratio		8.0	10.0
Max Efficiency		95%	95%

Figure 1 shows the power curve comparison for both the V150 turbine (4.2MW rated power) and the R212 turbine with a 7.4MW nameplate capacity. The GigaWind turbine's larger swept area leads to faster rise time of the power production with increasing wind speed. The 212m rotor diameter paired with a 7.4MW capacity leads to a lower specific power, and thus a lower rated speed than the V150-4.2MW.

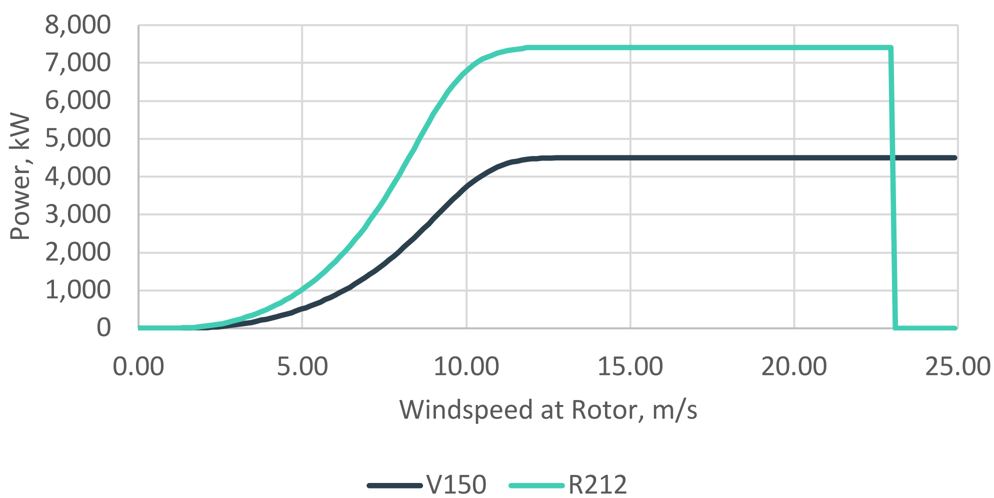

Figure 1: Power curve comparison.

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Wind Farm Energy Generation Performance

Losses for soiling, array, and availability were considered for both wind technologies. Array losses were prescribed directly due to detailed wake loss/interaction calculations being beyond the scope of this high geographic complexity study. The soiling losses are lowered for GigaWind due to being higher from the ground and the reduced air particulates observed at these heights. The array losses are also lower for GigaWind due to having fewer rows, and consequently lower cumulative wake losses across the farm landscape. The lifetime average availability of GigaWind is slightly higher due to having fewer components, and experiencing more steady, less gradient intensive, and less turbulent air which prolongs the lifetime of the components.

Table 2: Wind farm loss and interconnection costs.

		Standard Wind	GigaWind
Soiling Losses		5.8%	5.5%
Array Losses		4.4%	4.0%
Lifetime Average Availability		92.%	94%
Total Losses at Substation[1]		20.8%	19.0%
Grid interconnect line voltage	kV	400	400
Grid interconnect line distance	miles	11	11

Finally, as shown in Table 2, 11 miles of 400kV interconnection costs were assumed incurred by the wind project for all locations and both wind technologies.

To illustrate the differences in generation profile of the GigaWind technology as compared with standard onshore wind technology, Figure 2 provides the duration curves for both the V150 (standard wind platform) and the GigaWind R212 platform. Due to having overall lower losses (see Table 2), GigaWind provides more MW when operating at rated power, even though both technologies have the same total nameplate installed. Furthermore, because of GigaWind's lower rated speed, it is able to provide rated power for more hours of the year (roughly 2,800 hours as compared to standard wind's 1,700 hours). The elevated and more available production duration helps reinforce the higher capacity factor of the GigaWind technology.

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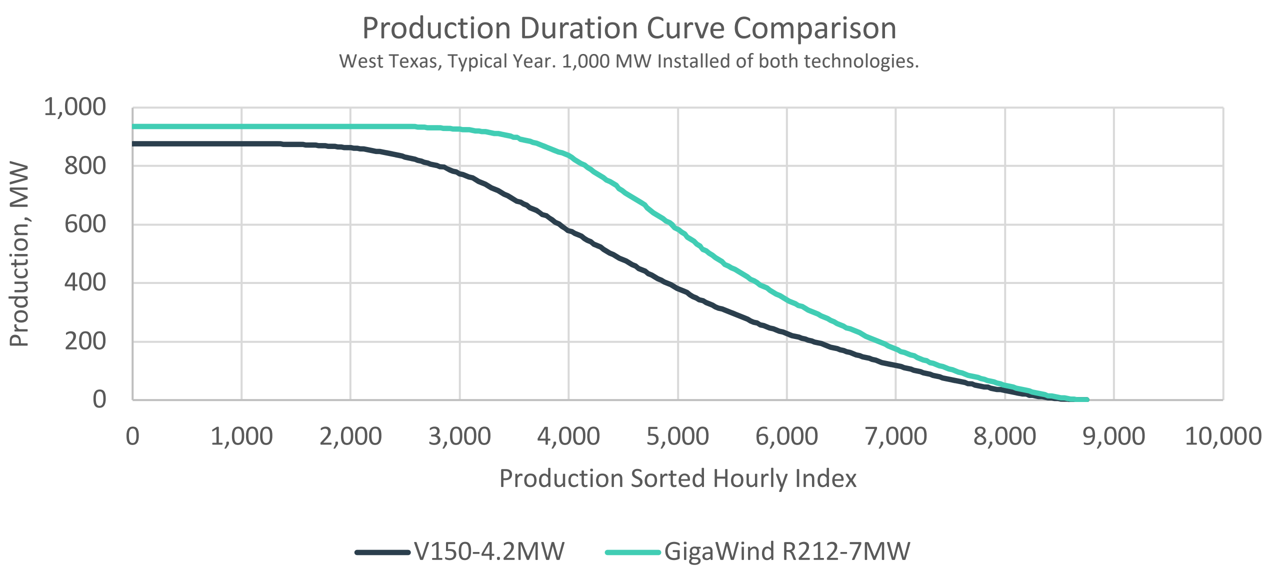

Figure 2: Production duration curves for standard and GigaWind technologies.

Performance statistics for the national grid, for both standard and GigaWind, are provided in Table 3.

Table 3: US National performance statistics for the DeSolve capacity buildout study.

		Standard Wind			GigaWind		
		MIN	MAX	AVG	MIN	MAX	AVG
Mean Wind Speed at Hub	m/s	3.38	9.39	6.62	3.50	9.84	7.11
Specific Power	W/m2	254	254	254	220	260	230
Turbine Nameplate Capacity	MW	4.50	4.50	4.50	7.77	9.18	8.11
Installed Windfarm Capital Cost	$/kW	1,570	1,666	1,612	1,338	1,612	1,464
Average Windfarm Annual Operating Cost	$/kW/Yr	15.44	44.71	32.19	13.76	44.02	33.21
Average Net Capacity Factor[1]		7.2%	54.4%	34.2%	9.6%	58.4%	41.4%
Levelized Cost of Energy[2]	$/MWh	24.44	202.63	45.52	19.45	134.11	31.02

The mean windspeed varied from as low as 3 m/s to as high as nearly 10 m/s, with averages between 6.6 and 7.1 m/s for standard and GigaWind, respectively. With specific power optimization, GigaWind selected rated powers between 7.8 and 9.2MW, with an average installed cost of $1,464/kw. GigaWind's average net capacity factor for the US was 41.4%, as compared with the V150's 34.4%. Finally, due to lower capital costs and high capacity factor, GigaWind's national average LCOE was 31.02$/MWh, which is approximately 32% lower than that of standard onshore wind technology.