US Green Hydrogen Production: Strategic Approaches to Enhancing Economic Viability and Market Development

by

Brandon Meehan

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Submitted to the MIT Sloan School of Management and
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Author	MIT Sloan School of Management and Department of Mechanical Engineering May 10, 2024
Certified by	Sili Deng, Thesis Supervisor Assistant Professor, Mechanical Engineering
Certified by	Daniel Freund, Thesis Supervisor Assistant Professor, Operations Management
Accepted by	Nicolas Hadjiconstantinou Chair, Mechanical Engineering Committee on Graduate Theses
Accepted by	Maura Herson Assitant Dean, MBA Program, MIT Sloan School of Management

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Abstract

As the global imperative for sustainable energy solutions intensifies, green hydrogen emerges as a potential player in a sustainable energy future. This thesis explores the viability and economic landscape of green hydrogen production within the United States. It places emphasis on the pivotal role of renewable energy credit (REC) matching criteria and strategic operational adjustments in enhancing its economic feasibility. Through a detailed examination of the effects of hourly and annual REC matching, this study illuminates the complex interplay between public policy, business strategies, and the inherent variability of renewable energy sources.

Central to this investigation is the assessment of two primary levers which may change the underlying economics of green hydrogen: REC matching criteria, which dictate the temporal alignment between renewable energy generation and hydrogen production, and strategic electrolyzer curtailment, a novel operational strategy designed to optimize the sale of both hydrogen and electricity. The analysis utilizes robust datasets including 4 years of hourly wind and solar resource availability in the U.S. at a 3km resolution, 4 years of hourly nodal power prices, and infrastructural cost data.

The findings reveal significant regional disparities in the cost-effectiveness of green hydrogen production. The middle regions of the U.S., particularly Texas, emerge as optimal locations. These disparities are further nuanced by the chosen REC

matching criteria, where less stringent annual matching notably reduces regional cost disparities by accommodating the variability of solar energy production. Moreover, strategic electrolyzer curtailment emerges as a critical mechanism for cost reduction, offering substantial savings, especially in regions characterized by high electricity price volatility.

This research contributes to the burgeoning field of green hydrogen studies by providing a comprehensive analytical framework that integrates technical, economic, and policy dimensions. It offers actionable insights for policymakers and industry stakeholders, suggesting pathways to enhance the competitiveness of green hydrogen. By meticulously balancing the imperative of sustainability with economic considerations, this thesis charts a course towards establishing green hydrogen as a significant contributor to the hydrogen market, poised to catalyze a profound shift in the U.S. decarbonization effort.

Thesis Supervisor: Sili Deng
Title: Assistant Professor, Mechanical Engineering

Thesis Supervisor: Daniel Freund
Title: Assistant Professor, Operations Management

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Chapter 1

Introduction

As the United States endeavors to align with the global initiative towards a more sustainable and environmentally-friendly future, green hydrogen emerges as a pivotal element within its energy strategy. Green hydrogen, produced via electrolysis powered by renewable energy sources, holds the potential to significantly reduce carbon emissions across various sectors, including transportation, industry, agriculture, and power generation.

However, the journey towards a green hydrogen economy is fraught with technical, economic, and policy-related challenges. The viability of green hydrogen as a sustainable energy solution within the United States hinges on a complex interplay of factors, including advancements in electrolysis technology, the availability and cost of renewable energy, and supportive public policies. This study aims to navigate these intricacies by assessing the economic landscape of green hydrogen production, exploring the impact of public policy mechanisms and business strategies on its feasibility and competitiveness.

Through a comprehensive examination of renewable energy credit matching constraints and strategic operational curtailment, this research seeks to illuminate pathways towards an economic integration of green hydrogen within the U.S. energy system. The overarching objective is to contribute valuable insights to industry stakeholders and policy makers.

1.1 U.S. Decarbonization

As part of its commitment to the Paris agreement, the U.S. has set very aggressive decarbonization goals in an effort to combat the effects of global warming. The U.S. aims to have net-zero greenhouse emissions by 2050. Carbon emissions have been steadily decreasing in recent years with net emissions of 6.7 GT CO2e[1] in 2005, 5.8 GT CO2e in 2015, and 5.5 GT CO2e in 2021, meaning there is 82% left of the 2005 emissions to reach its lofty goal. Several intermediate goals have also been set, the one being 50% reduction of the 2005 emissions by 2030, and 100% clean electricity by 2035. Achieving these goals requires a transformative approach to energy production, consumption, and infrastructure, leveraging both legislative frameworks and technological innovations. Among the key strategies is the advancement of green hydrogen technology, which is poised to play a pivotal role in the U.S.'s decarbonization efforts. [17]

Figure 1-1 shows U.S. greenhouse gas emissions breakdown by sector [33]. The bulk of carbon emissions come from transportation, electric power, and industry, though there are still meaningful emissions from the commercial and residential sector, and agriculture. Many of the carbon-free solutions for each sector involve moving away from the internal combustion engine and towards purely electric solutions. This means that not only will the electricity sector need to reduce its carbon emissions, it

[1] CO_2e is equivalent CO2 emissions. It also includes emissions of other greenhouse gases

will also need to grow substantially, around 40% by 2035 [6], in order to support the carbon-neutral goal of the other sectors.

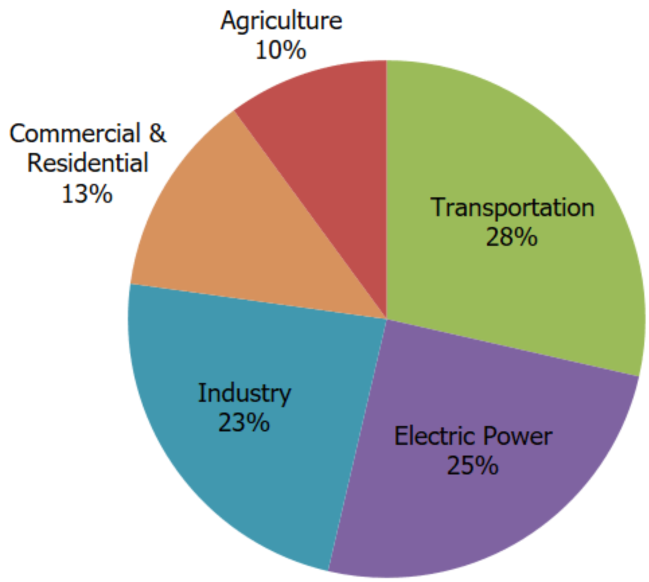

Figure 1-1: Total U.S. Greenhouse Gas Emissions by Economic Sector [33]

1.1.1 US Electricity Generation

US electricity is generated from multiple sources. Historically, the bulk of electricity was generated by coal power plants. By 2015, the widespread use of fracking technology in the early 2000s lowered the price of natural gas, and gas turbines surpassed coal as the greatest power generator. Other prominent power sources include nuclear power, and various renewables (mainly hydroelectric power, wind power, and solar power). Coal and natural gas emit carbon into the atmosphere, while nuclear, hydroelectric, wind and solar do not [8]. See Figure 1-2 for the breakdown of US power production by source.

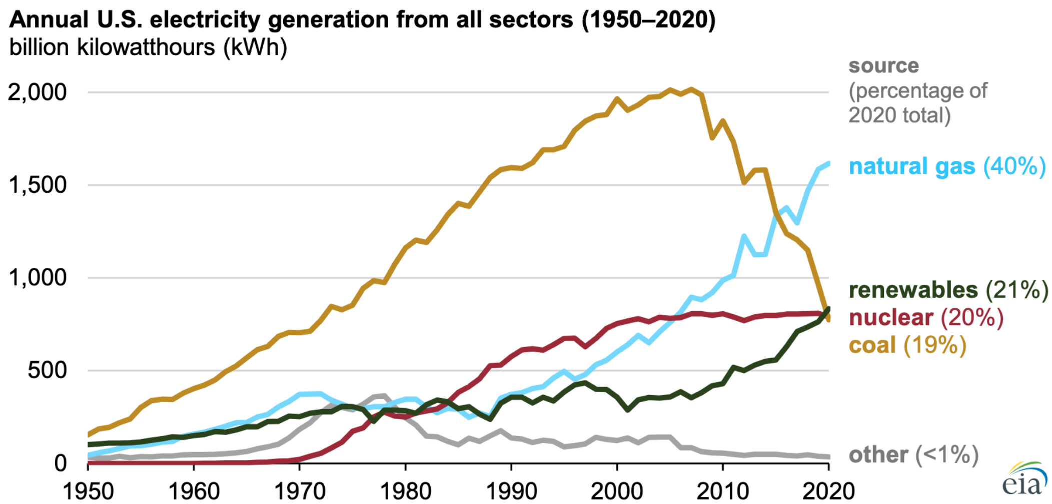

Figure 1-2: Total U.S. Greenhouse Gas Emissions by Economic Sector [8]

The transition away from coal and towards natural gas greatly reduced carbon emissions in the US. Coal plants emit approximately twice as much greenhouse gas as natural gas plants for the same volume of electricity. However, to reach net-zero by 2050, all natural gas plants must be retired or refurbished to burn renewable gas [6]. This presents an incredibly challenging problem, first simply due to the massive change in infrastructure, and second due to the variability associated with renewable power.

Renewable Energy Production Variability

Renewable energy can come in many forms: hydroelectric, wind, offshore wind, solar, geothermal, etc. However, the bulk of the energy transition in the US is expected to come from wind and solar resources. This is because wind and solar resources are both relatively cheap to produce and widely available across the U.S.

The greatest challenge with wind and solar power is the high production variability. Solar power only produces energy during the day, and wind power only produces energy while its windy. Thus, a controllable, throttle-able, on-demand power source is needed to fill in the gaps when renewable power generation cannot produce enough electricity to meet demand. Currently, this need is met by natural gas and coal power plants, but a low-carbon solution is needed to meet the U.S.'s decarbonization goals.

Potential solutions

Addressing the challenges posed by the variability of renewable energy sources requires a multifaceted approach, incorporating both innovative technologies and strategic infrastructural developments. This section elaborates on potential solutions that could facilitate the transition away from fossil fuels towards a more sustainable energy system, while also discussing the challenges associated with each solution:

1. **Expansion of Transmission Networks**: Enhancing the U.S. electricity transmission network is crucial for pooling energy supply and demand across broader geographic areas, thus mitigating discrepancies between energy generation and consumption. This strategy helps reduce the impact of variability in renewable energy production and prevents power shortages, ensuring a more reliable and balanced national energy supply. However, this approach faces significant regulatory and financial hurdles that can impede rapid deployment and integration. [21]

2. **Localized Generation Technologies**: Developing energy generation technologies near consumption sites can significantly reduce transmission losses and dependency on centralized power systems. This includes deploying rooftop solar panels, which, despite their benefit of reducing transmission losses, face challenges such as production variability and difficulties in scaling. Additionally,

Small Modular Reactors (SMRs) represent a significant technological innovation with the potential to transform local energy markets. By installing these reactors close to high-demand areas, they can provide a consistent, low-carbon power source. However, SMRs face their own set of challenges, including a complex regulatory environment, public perception issues, technological hurdles, and high costs. [1]

3. **Development of Energy Storage Technologies**: Addressing the production variability of wind and solar power requires robust energy storage solutions:

    (a) **Electrical Energy Storage**: Technologies like lithium-ion and iron-ore batteries are crucial for managing supply during periods of low renewable energy generation. However, these technologies face challenges in achieving the combination of high potential output and long-duration storage, and there are technological hurdles specific to materials like iron ore. [2]

    (b) **Thermal Energy Storage**: Capturing solar energy to heat materials stored in the ground provides a continuous energy supply, but requires significant volume and footprint to achieve enough thermal mass. [28]

    (c) **Gravitational Energy Storage**: This method uses excess energy to pump water into elevated reservoirs, allowing the generation of hydroelectric power during low renewable production periods. However, its feasibility is limited to areas near suitable dams.

    (d) **Chemical Energy Storage**: Producing green hydrogen through electrolysis stores energy in chemical form, which can be converted back to electricity or used as fuel. While promising, this solution faces high production costs and lacks extensive utility-scale infrastructure for widespread adoption.

Given the diverse nature of these challenges, it is likely that a combination of these solutions will need to be used in concert to effectively meet the U.S.'s decarbonization goals. Each technology and strategy offers unique benefits and faces distinct hurdles, underscoring the need for a comprehensive, integrated approach to achieving a sustainable and resilient energy future.

1.1.2 Green Hydrogen's Role in Decarbonization

Green hydrogen, produced through the electrolysis of water using renewable energy sources, offers a versatile and zero-emission energy solution. Its applications range from replacing fossil fuels in industrial processes, to generating ammonia for agricultural fertilizer, to serving as a storage medium for renewable energy, and to powering fuel cell vehicles. As the U.S. progresses towards its decarbonization targets, green hydrogen is poised to address some of the most daunting challenges in reducing emissions, especially in sectors traditionally reliant on internal combustion engines [9] [10] [11].

1.2 Hydrogen Market

The hydrogen market has witnessed significant growth, reaching 95 million tonnes with an estimated market value of around $200 billion in 2022. Its use are primarily for oil refining and the production of industrial chemicals [9]. Concurrently, hydrogen stands on the brink of broader application within the emerging green economy, pointing towards a future rich with potential for sustainable energy solutions.

1.2.1 Hydrogen Uses

Hydrogen's utility in the oil refining sector represents 43% of its global market demand, where it is predominantly produced on-site, either as a byproduct of other processes or through dedicated production efforts. Furthermore, industrial applications, such as ammonia and methanol production and the manufacture of chemicals for the steel and metal industry, consume 56% of the global hydrogen supply [9].

Looking ahead, the versatility of hydrogen positions it as a pivotal element in achieving decarbonization objectives. Notably, its potential applications in hydrogen fuel cell vehicles and hydrogen-powered gas turbines highlight the role of hydrogen as an integral component of a low-carbon future, offering sustainable alternatives to traditional fossil fuel-based technologies. However, several challenges impede its widespread adoption. For hydrogen fuel cell vehicles, key issues include the high cost of fuel cell production, the limited infrastructure for hydrogen fueling stations, and the efficiency of hydrogen production from renewable sources [12]. The challenge for hydrogen-powered gas turbines lies in adapting current turbine technology to handle hydrogen as a fuel, which involves significant engineering adjustments to accommodate hydrogen's high reactivity and chemical properties [23].

Additionally, the overall success of hydrogen in these applications hinges on its production methods. Currently, the majority of hydrogen is produced via processes that emit carbon, such as steam methane reforming, unless paired with carbon capture technologies. Transitioning to green hydrogen production, which uses renewable energy for electrolysis, is crucial but remains cost-prohibitive and energy-intensive. As such, further technological advancements and reductions in electrolyzer costs are essential to make green hydrogen economically competitive. Addressing these challenges requires not only technical innovations but also supportive policies and incentives to build the necessary infrastructure and market for hydrogen-based solutions. [11]

1.2.2 Hydrogen Production

The production of hydrogen is categorized by its associated carbon emissions: gray hydrogen is derived from fossil fuels without carbon capture; blue hydrogen is also fossil fuel-based but includes carbon capture to mitigate emissions; and green hydrogen, the most environmentally friendly option, is produced using renewable energy sources without direct emissions. Presently, the majority of hydrogen is produced via gray methods [11]. However, the shift towards green hydrogen production is deemed essential for meeting global decarbonization targets, underscoring the imperative for advances in electrolysis technology and the expansion of renewable energy capacities.

1.3 Green Hydrogen Plant

Green hydrogen emerges as a key player in the transition towards a net-zero emissions economy. This section explores the intricacies of a green hydrogen plant, which represents the convergence of renewable energy technologies and advanced electrolysis processes. By harnessing the power of renewable resources to split water into hydrogen and oxygen, green hydrogen plants offer a promising pathway to carbon-neutral energy production.

1.3.1 Anatomy

The green hydrogen production process involves using renewable electric power to split water into its constituent elements, hydrogen and oxygen. The breakdown of the key components of this process are:

1. **Electrolyzer:** At the heart of a green hydrogen project is the electrolyzer. This device consumes electric power to drive a chemical reaction known as electrolysis. During electrolysis, water (H2O) is split into hydrogen gas (H2) and oxygen gas (O2). The hydrogen gas is then captured.

2. **Renewable Power Generation:** The electricity required to operate the electrolyzer is generated from renewable energy sources. As these generators produce electricity with no carbon emissions, they produce renewable energy credits (RECs). Renewable power sources include wind, solar, hydroelectric and geothermal sources. Nuclear power may also be used to produce carbon-free hydrogen, though it still consumes uranium. Hydrogen produced from nuclear power is called pink hydrogen.

3. **Grid Connection:** A green hydrogen plant may also connect to the conventional electrical grid, serving multiple purposes. This connection can transfer power from renewable sources to the electrolyzer, act as a supplementary power source during low renewable generation, or facilitate the sale of excess renewable power back to the grid.

1.3.2 The Inflation Reduction Act and REC Matching

The Inflation Reduction Act (IRA) is a comprehensive legislative package passed in August 2022 by the U.S. Congress. It tackles a broad range of issues, one of which is climate change and energy. To that end, legislation provides financial incentives and support for renewable energy projects, carbon capture technologies, and the development of low-carbon infrastructure. These financial incentives extend to both low-carbon emission energy production and hydrogen production in the form of production tax credits (PTC). [25]

Renewable Energy Credits and Renewable PTCs

To facilitate a market for renewable energy, the U.S. and many world governments have created renewable energy credits (RECs). A REC represents a certain amount of energy generated from renewable sources, which can be sold or retired by consumers to claim renewable energy usage.

The IRA gives PTCs for REC generation. For qualifying newly constructed green energy generation infrastructure, a PTC of 2.5 cents per kilowatt-hour (kWh) is to be awarded, adjust for inflation each year. These awards are granted for the first 10 years of energy production. [14]

Green Hydrogen PTCs

For the production of green hydrogen, an PTC of $3/kg is granted for the first 10 years of production, adjusted for inflation [32]. This PTC stacks with the PTC granted for green energy generation. Thus, a green hydrogen plant may harvest PTCs from both wind/solar energy generation, and the PTCs from green hydrogen production.

REC Matching Criteria

The temporal matching of RECs with hydrogen production is a hot debate for green hydrogen production. When green hydrogen is produced, the associated RECs from renewable energy must also be retired. In the most stringent case of REC matching, RECs must be produced at the same time that the hydrogen is produced. Thus, whenever renewable power sources are not generating (when its not sunny or windy), green hydrogen production must cease. In the least stringent case of REC matching, the timing of REC production and consumption does not matter. For example, RECs from July could be used to offset conventional grid energy consumption in December. [30] [34]

The two most commonly discussed forms of REC matching are hourly matching and annual matching. In hourly matching, RECs used for green hydrogen production must originate from the same hour that the green hydrogen is produced. In annual matching, RECs used for green hydrogen production must originiate from the same year that the hydrogen is produced. [30] [34]

Under hourly matching, green hydrogen production must cease frequently. For example, in a green hydrogen plant with only solar power, hydrogen production at night is not feasible[2]. However, under annual production, excess RECs may be generated during the day, and then consumed during periods without sunlight.

1.3.3 Grid Interactions and Power Markets

Understanding power markets and grid interactions is essential for green hydrogen plants, which often engage in buying and selling electricity.

Power Dispatch

The way power market regulators dispatch generators (tell generators to turn on) is quite complex. Unregulated power markets (markets run privately instead of by the state) stay true to the principals of economic supply and demand. Market administrators predict the quantity of electricity demanded at a given time. Electricity demand is generally assumed to be price inelastic (demand does not vary with price). Power generators (supply) then bid into the market at their marginal cost to produce.

[2]However, solar panels used with battery storage would allow for hydrogen production at night, though this study does not analyze that type of system

The lowest cost generators are first dispatched into the market, followed by the subsequent cheapest producers until the quantity supplied is equal to the demand. The price of electricity is then set by the last bid by the suppliers.

Renewable energy sources (wind, solar, hydroelectric) have the lowest marginal cost of production. Their marginal cost of production is near zero, with most of their cost simply coming from maintenance. Natural gas has the next lowest marginal cost of production, driven by the price of natural gas. Finally, coal has the highest marginal cost of production, driven by the cost of coal.

Transmission, Congestion, Locational Marginal Price

Transmission also plays a major role in determining the price of power. Its not enough to just consider the supply and demand of electricity across the entire region. Electricity must also be transported through power lines.

The electric grid contains many focal points called nodes. Nodes are places where generators may supply electric power, and consumers may consume electric power. Transmission is used to connect these nodes and pool the supply and demand which exists in a region. In this way, power markets are more stable. If there is a power deficit at one node, excess power from another node may be shuttled to the power-deficient node.

If the demand for power transported through a transmission line is greater than the line capacity, the transmission line is said to have congestion. In order to account for congestion, the power prices are raised at the node with high power demand. In this way power suppliers closer to the node (that won't need to use the congested transmission line) are more incentivized to produce power. In turn, power consumers are also disincentivized from consuming power.

Location marginal price (LMP) is the power price at a specific node. It accounts for both the regional supply and demand of power, as well additional costs from congestion. The price at which power is sold or purchased is set by the LMP of the respective node. Additional fees are also associated with the purchase of power.

Demand Response

Demand response is a concept where large energy consumers are paid by market organizers to curtail (limit) their electricity consumption when electricity prices are high. This reduces the congestion through transmission lines, and in turn reduces the LMP.

1.4 Choosing the Best REC Matching Constraint: A Balance of Sustainability and Economics

The method chosen for matching RECs to hydrogen production plays a pivotal role in defining the sustainability profile of the resulting hydrogen. Stringent REC matching criteria, which mandate the exclusive use of renewable energy for hydrogen production, undoubtedly underscore a commitment to maximum sustainability. This approach aligns with the purest environmental ethos, ensuring that hydrogen production contributes minimally to carbon emissions. However, the adoption of less stringent REC matching, which permits the supplementation of renewable power with conventional grid energy during periods of low renewable output, introduces a pragmatic dimension to green hydrogen production. While this may slightly dilute the "greenness" of the hydrogen produced, it enhances economic viability by ensuring continuous production and may ultimately result in a much larger green hydrogen market and a much greater sustainability impact. This balancing act between sustainability and economics is essential in shaping policies and strategies that will support the growth and acceptance of green hydrogen as a cornerstone of the future energy landscape.

1.4.1 Recent Updates on the IRA

At the end of 2023, the Treasury Department's provided more clarity into the REC matching requirements for green hydrogen production. They plan to gradually shift towards more stringent renewable energy matching criteria using a phased approach: green hydrogen plants must transition from annual to hourly matching by 2028. This transition underscores a nuanced policy effort to align hydrogen production more closely with real-time renewable energy generation, enhancing the sustainability and "greenness" of hydrogen.

While the decision for matching criteria has already been made, this paper will still evaluate and compare the two most popular forms of REC matching: hourly and annual. Through the analysis, we can draw conclusions about how the Treasury's decision may change the green hydrogen market, and make recommendations on potential changes.

1.5 Research Objective

Green hydrogen could be a key contributor to sustainable energy systems, although the extent of its impact remains uncertain. This study seeks to assess the viability of green hydrogen within the United States, investigating the influence of public policy (through matching constraints) and business practices (via strategic curtailment) on its economic landscape.

1.5.1 Problem Statement

In general, this thesis aims to address the following questions:

1. What is the cost of producing green hydrogen in the U.S. as compared to conventional gray hydrogen?

2. Where may green hydrogen be economically produced, and with what mix of renewable energy technologies?

3. What are some potential levers which may change the underlying economics?

Two levers are investigated: matching criteria, and strategic electrolyzer curtailment.

Matching Criteria and its Effect on Renewable Energy Technology Mix

Initially, I delve into the effects of renewable energy credit (REC) matching requirements in the Inflation Reduction Act (IRA), focusing on two primary models: hourly and annual REC matching. Hourly REC matching, the stricter of the two, mandates that green energy generation *each hour* surpasses the energy consumed in hydrogen production. Essentially, all energy must be derived from green energy sources. Conversely, annual REC matching requires that green energy generation *each year* exceeds the energy consumed in hydrogen production. This allows for periods of time when green energy is produced in excess (and sold to the grid) and periods of time when less green energy is produced than consumed (meaning that energy is purchased from the grid). These criteria have profound implications on the mix of renewable energy technology used for green energy production, influencing both the geographical distribution of green hydrogen facilities in the U.S. and the overall production costs.

Hourly REC matching may disadvantage energy technologies with high variability. With highly variable energy production, electrolyzer run-time will decrease leading to a lower production volume. Thus, the cost of electrolyzer infrastructure will increase on a per-unit basis. Although both wind and solar power sources exhibit variability, solar energy's output is concentrated to just daylight hours, making it substantially more variable. Consequently, hourly REC matching might incline towards wind or combined wind and solar solutions due to their relatively steadier energy supply.

Conversely, annual REC matching is less affected by power output variability, tending to favor the most cost-effective green energy sources. Since the costs of wind and solar energy production are closely tied to weather conditions, annual REC matching could encourage more homogeneous energy solutions, either all-wind or all-solar. However, the price of power also plays a more significant role in annual matching, as power is both purchased (with fees) and sold to the grid more regularly. Thus, mixing could help protect against intermittent periods of high power prices. Also a greater number of purchasing fees would also encourage greater mixing.

Thus, the choice of matching criteria has a profound effect on what the green hydrogen economy will look like in the U.S. Under hourly matching, we expect to see a greater number of mixed renewable energy solutions with intermittent operations and unsteady hydrogen production. Under annual matching, we expect to see a greater number of homogeneous renewable energy solutions with steady electrolyzer operations and hydrogen output. These significant financial and operational impacts don't just affect the producer, but also the consumer of green hydrogen. Under hourly matching, customers who wish to have a steady supply of green hydrogen will have to adapt for intermittent operations. To do this, they may have to pay for costly storage (either green energy storage or hydrogen storage), and come up with plans for green hydrogen shortages.

How do REC matching requirements transform the landscape of green hydrogen production in the U.S.? Do they confer advantages to specific technologies, such as wind or solar or a mix of the two? Do these requirements offer benefits to particular regions more significantly than others? What is the equivalent dollar-value of annual matching vs hourly matching constraints?

Strategic Electrolzyer Curtailment Strategy

Then, I examine how businesses may alter operations to lower production costs. A facility producing green hydrogen utilizes both renewable and conventional grid electricity (in the case of annual matching) to power electrolyzers for hydrogen generation, with surplus power being sold back to the grid. Therefore, there is always an opportunity cost to producing hydrogen: the cost of energy. By strategically curtailing electrolyzer load in response to power prices, hydrogen producers may optimally monetize both hydrogen and energy. This leads to a natural question:

Can strategic curtailment of the electrolyzer lower the levelized cost of hydrogen, and if so, by how much? Is the impact of strategic curtailment more pronounced under annual or hourly matching requirements? Furthermore, does it have a more significant effect when using wind or solar energy solutions?

1.5.2 Business Implications

Following the enactment of the Inflation Reduction Act (IRA), this thesis gains particular relevance within the energy sector. The IRA introduces new tax incentives, prompting energy companies to reassess the economic viability of green hydrogen production. This research aims to identify strategies for reducing the levelized cost of hydrogen (LCOH), thereby enhancing the feasibility of green hydrogen as an energy source.

Central to this analysis are the renewable energy credit (REC) matching requirements mandated by the IRA. The thesis evaluates how these matching criteria might influence the costs and feasibility of green hydrogen initiatives, offering fresh perspectives on the regulatory landscape. By scrutinizing the interplay between IRA provisions and green hydrogen project economics, the research endeavors to provide actionable insights that could lower the LCOH.

Additionally, this thesis investigates the impact of strategic curtailment strategies on green hydrogen plant operations. These insights offer businesses practical guidance to maximize marginal revenue. This approach provides an additional pathway for companies to gain a competitive advantage in an evolving green hydrogen market.

In essence, this study is designed to furnish energy companies and policymakers with strategic insights for navigating the nascent green hydrogen market. It aims to influence both corporate decision-making and public policy formulation, steering them towards more sustainable and economically viable energy solutions.

1.5.3 Hypothesis

This study proposes several hypotheses to guide its investigation. These hypotheses will be evaluated by examining the design of green hydrogen plants across the entirety of the continental U.S.

1. **Green hydrogen production cost:**

    (a) **Under annual REC matching**, more than 10% of geographic locations in the U.S. may produce green hydrogen at cost parity with gray hydrogen. *Cost parity will be assessed at the mean gray hydrogen price of $2.13 [29].*

(b) **Under hourly REC matching**, less than 2% of geographic locations in the U.S. may produce green hydrogen at cost parity with gray hydrogen. *Less than 2% of green hydrogen designs will fall below $2.13 [29].*

2. **The value of annual matching over hourly matching constraints** exceeds half the price of gray hydrogen. The difference in production costs will be assessed at the median LCOH for all geographic locations in the U.S.

3. **Renewable energy composition:**

    (a) **Hourly REC matching** is predicted to lead to a higher adoption of wind energy solutions than annual matching; a higher adoption of hybrid (wind and solar) energy solutions than annual matching; and a lesser adoption of all solar energy solutions than annual matching.

    (b) **Annual REC matching** is predicted to favor homogeneous energy solutions (either all-wind or all-solar).

4. **Strategic electrolyzer curtailment effects:** Strategic electrolyzer curtailment will reduce the cost of green hydrogen across all scenarios, irrespective of the REC matching requirement or geographic location. However, the cost reduction will be most pronounced under annual REC matching conditions and in regions characterized by high electricity price volatility.

1.5.4 Research Objectives

In order to systematically investigate the proposed hypotheses, this study sets forth to evaluate the ideal design and performance of green hydrogen plants under the following conditions:

1. Green hydrogen plant design under ***hourly*** REC matching criteria
    (a) ***without*** strategic electrolyzer ***curtailment***.
    (b) ***with*** strategic electrolyzer ***curtailment***.
2. Green hydrogen plant design under ***annual*** REC matching criteria
    (a) ***without*** strategic electrolyzer ***curtailment***.
    (b) ***with*** strategic electrolyzer ***curtailment***.

Results for the entirety of the continental U.S. will be generated for these objectives. Then, the initial hypotheses may be tested by analyzing the statistics of the results.

1.5.5 Planned Recommendations and Insights

The culmination of this research offers a suite of targeted recommendations for both policymakers and businesses, designed to navigate the complexities of the green hydrogen market. For policymakers, the study suggests specific adjustments to the green hydrogen Production Tax Credit (PTC), aiming to align its competitiveness with that of gray hydrogen. Additionally, insights into the trade-offs of annual versus hourly REC matching provide a strategic lens through which policy can influence the growth of the green hydrogen economy. On the business front, the research points out optimal geographic regions within the U.S. for green hydrogen production, underscoring the benefits of strategic curtailment and the potential financial advantages of engaging in demand response programs with ISOs. These recommendations not only pave the way for a more economically viable green hydrogen sector but also align with broader environmental and sustainability goals.

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Chapter 2

Data Sources

The primary datasets used in the study are weather data and power price data. The study uses hourly data from the years of 2019 through 2022. Other non-temporal data include infrastructure costs, operational costs, tax credits, and tax rates.

2.1 Wind and Solar Resource Data

The hydrogen plant design considered in this study consists of wind power generation, solar power generation, and an electrolyzer. Thus, historical wind and solar resource across the United States is a primary data input.

Wind and solar data were obtained from the National Oceanic and Atmospheric Administration (NOAA) High Resolution Rapid Refresh (HRRR) dataset. The HRRR dataset is a real-time, 3-km resolution, hourly updated weather forecasting dataset covering the the entire continental US. It contains over 160 measurements taken at various altitudes above the earth's surface, for approximately 2 million coordinates. It is also completely public through several common sources (AWS, Google) [22]. The data can be easily accessed using the HERBIE software [3]. The measurements of interest for this study are those pertaining to wind and solar resource. After data reduction, the 4 year weather dataset is just under 250GB of data.

Table 2.2: Meteorological Data Variables from NOAA HRRR

Data variables	Wind Speed North/South	80m
	Wind Speed East/West	80m
	Temperature	2m
	Downward Short Wave Radiation Flux	surface-level
Frequency	Hourly, instantaneous	
Resolution	3km	
Datapoints	2M coordinates	
Data size	250GB	
Source	NOAA HRRR	

2.1.1 Wind Resource

For wind resource, the notable data variables are wind speed North, v_{80m}, and wind speed East, u_{80m}, at 80m above surface level. These two parameters may be combined to obtain the total wind speed, V_{80m}, at the approximate height of most industry wind turbines.

$$V_{80m} = \sqrt{{v_{80m}}^2 + {u_{80m}}^2}$$

The total wind speed may then be fed into a typical wind turbine power curve to obtain the wind net capacity factor (NCF). For this study a GE Model 2.5XL Wind Turbine Power Curve (Figure 2-1) from the National Renewable Energy Laboratory

(NREL) System Advisor Model (SAM) was used to derive the NCF [31]. There are three noteworthy inflection points on the power curve:

1. For wind speeds under 3.5m/s, the power output of the wind turbine is zero.
2. For wind speeds between 12.5 and 25m/s, the power output of the wind turbine is at its maximum, meaning the NCF is 1.
3. For wind speeds above 25m/s, the power output of the wind turbine returns back to zero. Above 25m/s, the wind turbine blades are angled in a way that the motor does not turn to avoid potential damage.

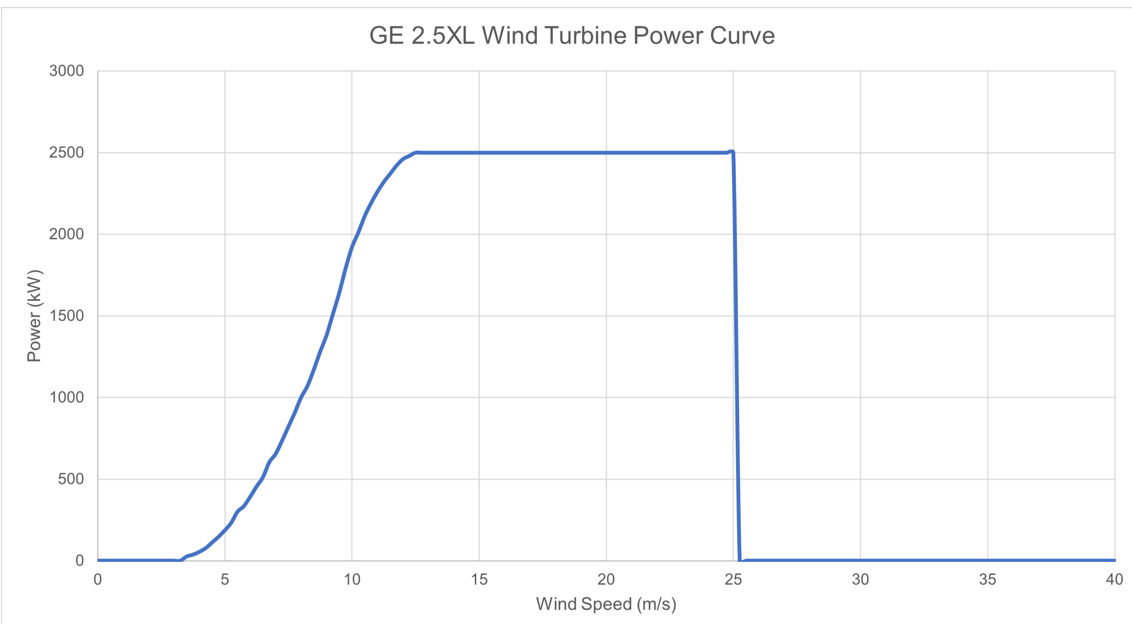

Figure 2-1: GE 2.5XL Wind Turbine Power Curve [31]

The final wind NCF results may be observed in many different time horizons. To properly appreciate the granularity of this dataset, Figure 2-2 shows the wind NCF data for one point in time.

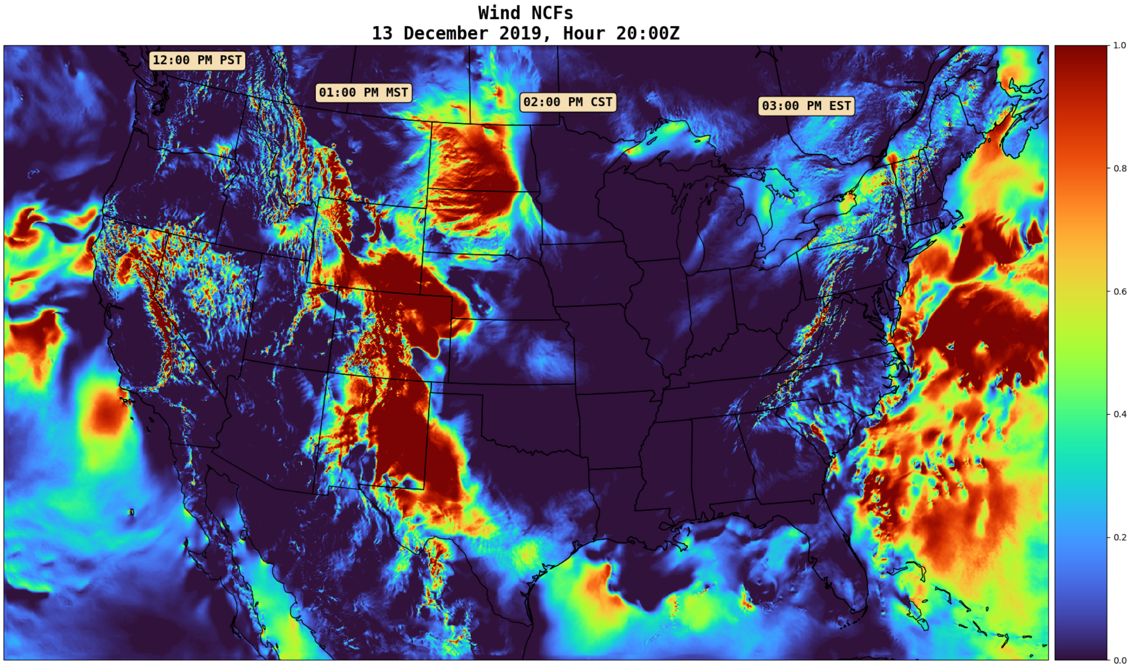

Figure 2-2: Wind NCF, 13 Dec 2019

Figure 2-3 displays the average wind NCF for the continental US. It shows very strong wind resource in the midwestern regions, typically along mountain range ridges.

Many seasonal patterns may also be observed in the data, on a mean 24-hour scale, and on a mean monthly scale. Appendix A shows these results. Generally, wind resource is stronger during night-time hours and winter months, and weaker during day-time hours and summer months.

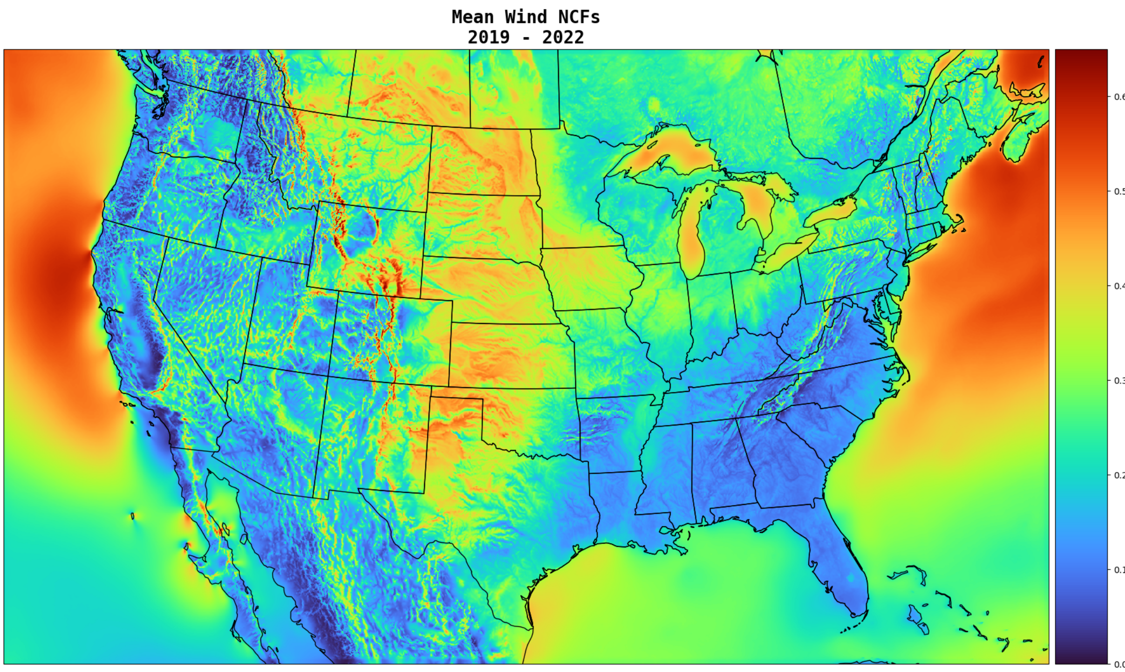

Figure 2-3: Mean Wind NCF 2019 - 2022

2.1.2 Solar Resource

For solar resource, the most notable data is downward short-wave radiation flux at the earth's surface. This is synonymous with more the commonly used term, global horizontal irradiance (GHI), which is the primary input for calculating solar panel power output. Another important data variables is the air temperature at 2m above the earth's surface. Solar panel and inverter performance varies with temperature.

For this study, solar panel performance specifications were obtained from NREL SAM. The solar panel model is a Jinko Solar Company JKM400M-72-V [31]. The performance specifications are listed in Table 2.3. A direct-current (DC) to alternating-current (AC) ratio of 1.3 was used for the system, meaning that the maximum power output of the solar panels (DC) is 1.3 times greater than the maximum power output of the power inverter (AC). It is economical to overbuild the solar panel output to maximize the inverter use.

Table 2.3: Jinko Solar Company JKM400M-72-V
Performance Specifications [31]

Max Power	$P_{\mathrm{pan}_{\mathrm{max}}}$	400 Wdc
Irradiance Reference	G_{ref}	1000 W/m^2
Cell Temperature Reference	T_{ref}	25 °C
Temperature Adjustment Coefficient	α	-1.61 W/°C

With the weather data and performance specifications, it is possible to calculate the solar panel power output and NCF using the following equations where P_{pan} is the solar panel power output, GHI is the global horizontal index, G_{ref} is the reference GHI from the solar panel specifications, α is the temperature adjustment coefficient,

T_{2m} is the ambient temperature 2 meters above the surface, T_{ref} is the reference temperature from the solar panel specifications, η_S is with solar NCF, and $R_{DC/AC}$ is the DC-to-AC ratio [16].

$$P_{pan} = min\left(\frac{GHI}{G_{ref}} + \alpha\left(T_{2m} + T_{ref}\frac{GHI}{800} - T_{ref}\right),\ P_{pan_{max}}\right) \tag{2.1}$$

$$\eta_S = min\left(\frac{P_{pan}}{P_{pan_{max}}}R_{DC/AC},\ 1\right) \tag{2.2}$$

The final solar NCF results may be observed in many different time horizons. To properly appreciate the granularity of this dataset, Figure 2-4 shows the solar NCF data for one point in time. It is easy to visualize clouds covering certain portions of the U.S.

Figure 2-5 displays the average solar NCF for the continental U.S. It shows very strong solar resource in the Southwest region of the US.

Many seasonal patterns may also be observed in the data, on a mean 24-hour scale, and on a mean monthly scale. Appendix B shows these results. Generally, solar resource is stronger during day-time hours and summer months, and weaker during night-time hours and winter months.

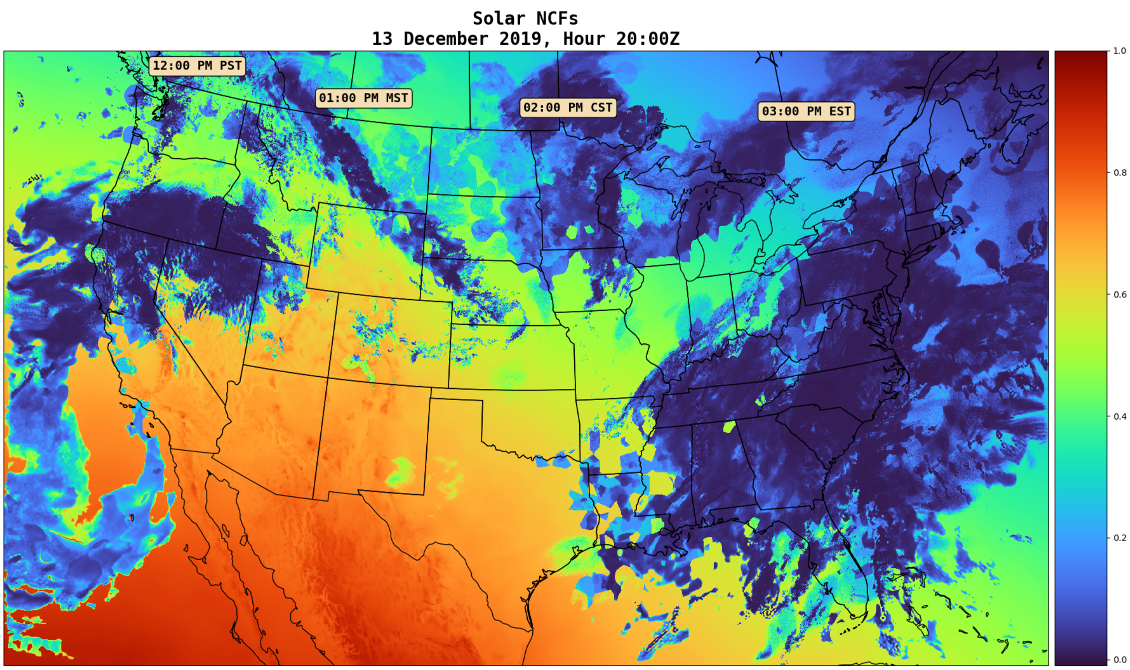

Figure 2-4: solar NCF, 13 Dec 2019

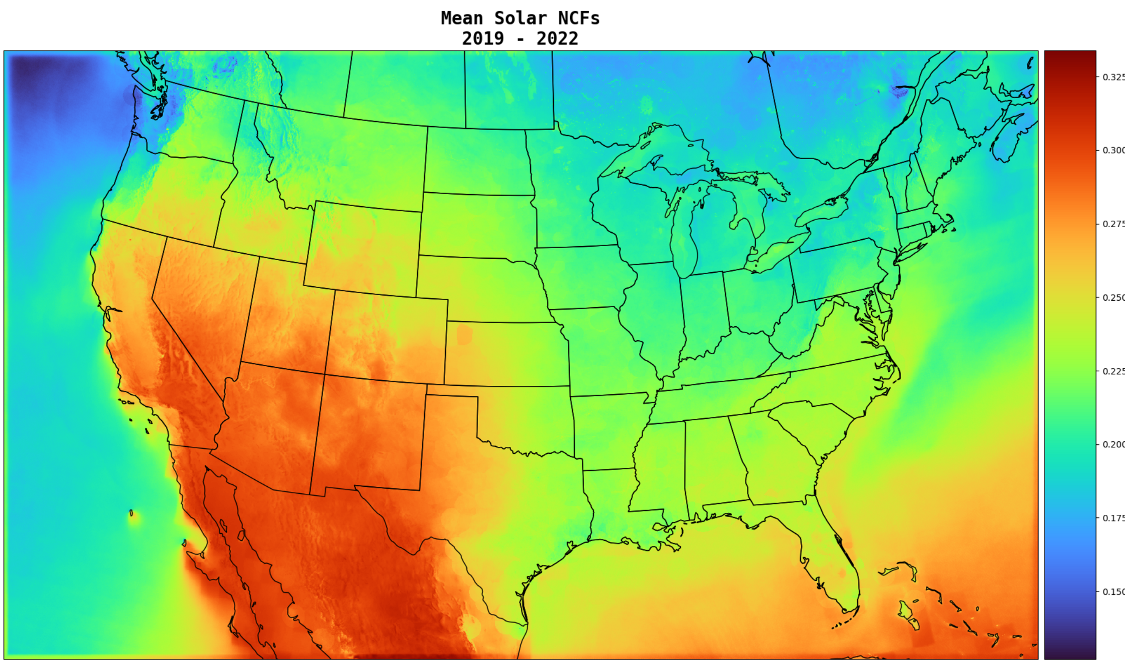

Figure 2-5: Mean Wind NCF 2019 - 2022

2.1.3 Anti-Correlation of Wind and Solar Resources

An important conclusions may be drawn from the seasonal patterns that exist within renewable energy resource. As described before, wind resources generally produce more during nighttime hours, and during the winter months. On the other hand, solar resources produce more during daytime hours, and during the summer. Thus, wind and solar resource exhibit slight negative correlation. See Appendix A and B for more insights into the seasonal patterns of wind and solar resources.

This anti-correlation can be useful for green hydrogen production. When matching criteria are strict, like hourly matching, an inherent penalty exists when renewable energy is not produced: the electrolzyer must shutdown and stop producing hydrogen. This in turn will raise the LCOH. Thus, as the temporal matching of hydrogen becomes more strict the advantage conferred by anti-correlation will become more drastic.

2.2 Power Price Data

Green hydrogen plants have frequent interactions with the electric grid. Power is frequently purchased from (in the case of annual matching) and sold to the electric grid. Thus, the price of power is critical data for the study.

This study uses locational marginal price (LMP) data from various Independent System Operators (ISOs) who run power markets. The ISOs include California ISO (CAISO) [5], the Electric Reliability Council of Texas (ERCOT) [13], Midcontinent ISO (MISO) [18], New England ISO (NEISO) [15], New York ISO (NYISO) [7], Pennsylvania-New Jersey-Maryland ISO (PJMISO) [24], and Southwest Power Pool Iso (SPPISO) [27]. The dataset contains average hourly LMPs for over 15,000 nodes across the 7 unregulated power markets. After data reduction, the 4 year power price dataset is around 400 MB of data.

Table 2.6: Power Price Data Specifications

Data Variables	Locational marginal price
Frequency	Hourly, time-averaged
Datapoints	17,000 nodes
Data Size	400MB
Source	Various

2.2.1 Locational Marginal Price

Figure 2-6 displays the median power price for each node in the dataset. It generally shows high power prices in California (CAISO) and in the Northeast (NEISO). However, it should be noted that the distribution of power prices varies greatly across ISOs. ERCOT, for instance, has highly variable LMPs compared to its counterparts. Figure 2-7 shows the standard deviation of power prices for each node in the dataset.

Again, seasonal patterns may also be observed in the data, on a mean 24-hour scale, and on a mean monthly scale. Appendix C shows these results. Considering annual seasonality, power prices are higher during the middle of Summer (when people run their air conditioning) and middle of Winter (when people run their heaters), and lower during the shoulder months. Considering daily seasonality, power prices are higher in the late afternoon (right after people get home from work) and lower during the nighttime.

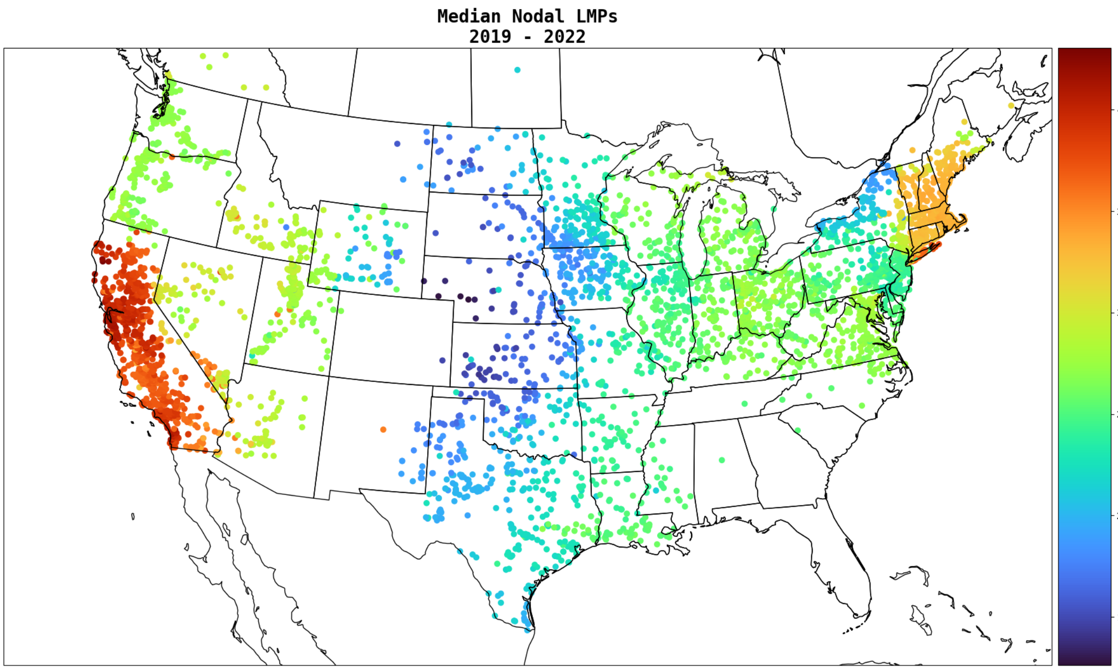

Figure 2-6: Median LMP ($/MWh) 2019 - 2022

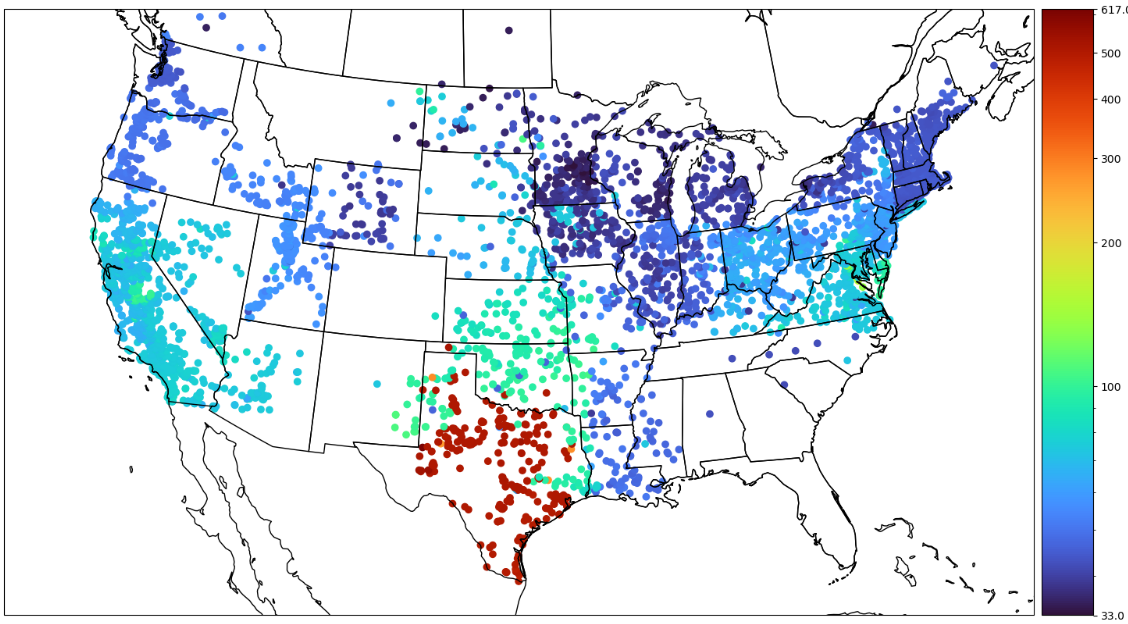

Figure 2-7: Standard Deviation of LMP (\$/MWh) 2019 - 2022

2.3 Non-temporal Data

2.3.1 Infrastructure Data

The costs associated with renewables production will not be explicitly stated, though projections may be found with a subscription to Bloomberg New Energy Finance. The data includes capital expenditures, operational expenditures, and spend curves associated with wind farms, solar farms, and electrolyzers. The data also included some operational performance specifications, such as the electrolyzer specific energy consumption. To give a more clear picture of each data, Table 2.7 shows each infrastructure costs, its unit, an order of magnitude, and a brief description.

Table 2.7: Infrastructure Data

Data	**Unit**	**Order of Magnitude**	**Description**
Wind Farm CapEx	$ / kW	1,000	The capital cost associated with building a wind farm on a per-kilo-watt basis.
Solar Farm CapEx	$ / kW	1,000	The capital cost associated with building a solar farm on a per-kilo-watt basis.
Electrolyzer CapEx	$ / kW	1,000	The capital cost associated with building an electrolyzer on a per-kilo-watt basis.
Transmission Capex	$ / mi	1,000,000	The capital cost associated with building a transmission line on a per-mile basis.
Wind Farm OpEx	$ / MWh	1	The operational cost associated with producing one mega-watt-hour of power from a wind farm.
Solar Farm OpEx	$ / MWh	1	The operational cost associated with producing one mega-watt-hour of power from a solar farm.
Electrolyzer OpEx	$ / kW	100	The operational cost associated with operating a one kilo-watt capacity electrolyzer.
Infrastructure Spend Curves	%	10	The percent of capital costs spent each year leading up to the commencement of operations.
Electrolyzer Specific Consumption	kWh / kg	10	The number of kilo-watt-hours required to produce one kilogram of hydrogen.

2.3.2 Regulatory

Other non-time series data include federal and state tax rates, MACRS (accelerated) depreciation allowances, and production tax credit (PTC) data. The federal tax rate was assessed at 21% and the state tax rate was assessed at 4%[1]. The depreciation associated with green hydrogen plant assets was assessed using a combination of 5-year and 15-year MARCRS depreciation. Depreciation tables may be found on IRS website [26]. Finally, the production tax credit for green hydrogen was assessed at $3/kg [32], and the production tax credit for renewable energy production was assessed at 2.5 cents/kWh, inflation adjusted to the commencement of operations [14].

[1]For simplicity, the tax rate was held constant accross the entire U.S.

Chapter 3

Methods

The green hydrogen plant design in this study consists of three main components: wind farm, solar farm, and electrolyzer. An optimal green hydrogen plant design will balance the sizing of wind generation, solar generation, and electrolyzer to minimize the LCOH. To meet the "green" requirement the design must also meet the corresponding matching requirements set out by the IRA.

This section provides on overview of how to assess green hydrogen plant designs (what is the levelized cost of hydrogen), and provides methods for optimizing the design of green hydrogen plants under certain conditions. These methods will then be used to meet the research objective outlined in section 1.5.4.

First, an intuitive model for green hydrogen plants is developed. This model assesses hydrogen plant operations on the hourly level over an entire year and a lifetime level (5 years of construction and 30 years of operation). It is helpful for understanding how operations translate to finances.

Second, a simplified version of the LCOH function is developed. It is still just as robust as the intuitive model, but lays the groundwork for coding, computational methods, and optimization methods.

Finally, optimization methods are discussed for each of the four cases laid out in the objectives section 1.5.4.

3.1 Intuitive Approach to Green Hydrogen Plant Modeling

First, an intuitive model for green hydrogen plants is developed. This model is intended to illustrate how each piece of a green hydrogen plant interact and how those interactions contribute to finances. It is not is not set up for computational algorithms.

It is also worth noting that the model developed in this section does not include the strategic curtailment strategy. That strategy is mathematically introduced in Section 3.3.

3.1.1 Annual (Physical) Model

The outputs of the annual (or physical) model are the annual wind energy generation, the annual solar energy generation, the annual hydrogen production, the annual revenue associated with energy sales, and the annual costs associated with energy purchases (only in the case of annual matching). To generate these outputs, one must look at each hour, h, in the year.

Annual Energy Generation

To calculate annual wind energy generation, E_{W_y}, and solar energy generation, E_{S_y}, one must sum product of the wind size, W, or solar size, S, with the net capacity factor, η, with for each hour, h, in the year. For reference, there are 8760 hours in a year.

$$E_{W_y} = \sum_{h=1}^{8760} \eta_{W_h} W \tag{3.1}$$

$$E_{S_y} = \sum_{h=1}^{8760} \eta_{S_h} S \tag{3.2}$$

Annual Hydrogen Production

Hydrogen production is linked to energy production through the matching constraints. To simplify the model going forward, it is helpful to classify hours in which more energy is produced than the electrolyzer capacity and hours in which less energy is produced than the electrolyzer capacity. Let Z represent the electrolyzer capacity. Let η_{Z_h} represent the electrolyzer target throttle in each hour, which may assumed to be 100% for now. Let the overproduction hours be classified as set_o and the underproduction be classified as set_u.

$$set_o \text{ contains all } h \text{ for which } \eta_{W_h} W + \eta_{S_h} S \geq \eta_{Z_h} Z$$

$$set_u \text{ contains all } h \text{ for which } \eta_{W_h} W + \eta_{S_h} S < \eta_{Z_h} Z$$

To calculate the annual hydrogen production, one must sum the quotient of the electrolyzer energy consumption with the electrolyzer specific energy consumption, SEC_Z, for each hour in the year. In the case of annual matching, the renewable power generation will be sized so that the electrolyzer may run at full throttle all of the time. Thus, the electrolyzer consumption is constant each hour, and equal to the electrolyzer capacity, $\eta_{Z_h} Z$. In the case of hourly matching, the electrolyzer may not run at full throttle all of the time, due to the stricture matching constraint.

Thus, the electrolyzer energy consumption must be less than or equal to the energy generation from wind and solar.

$$\text{Annual matching: } H_{2_y} = \frac{1}{SEC_Z} \sum_{h=1}^{8760} \eta_{Z_h} Z \tag{3.3}$$

$$\text{Hourly matching: } H_{2_y} = \frac{1}{SEC_Z} \sum_{h=1}^{8760} \begin{cases} \eta_{Z_h} Z & \text{for } h \text{ in } set_o \\ (\eta_{W_h} W + \eta_{S_h} S) & \text{for } h \text{ in } set_u \end{cases} \tag{3.4}$$

Annual Grid Revenue and Costs

When more energy is produced than the electrolyzer capacity, energy may be sold to the grid, resulting in annual grid revenue, R_{grid_y}. In the case of annual matching only, energy may be purchased from the grid when generation is less than electrolyzer capacity, resulting in annual grid costs, C_{grid_y}. The price at which energy is sold and purchased, LMP_h, changes each hour. Note that energy purchases have additional fees, while energy sales do not.

$$R_{grid_y} = \sum_{h=1}^{8760} LMP_h * \begin{cases} \eta_{W_h} W + \eta_{S_h} S - \eta_{Z_h} Z & \text{for } h \text{ in } set_o \\ 0 & \text{for } h \text{ in } set_u \end{cases} \tag{3.5}$$

$$C_{grid_y} = \sum_{h=1}^{8760} (LMP_h + Fees) * \begin{cases} 0 & \text{for } h \text{ in } set_o \\ \eta_{Z_h} Z - (\eta_{W_h} W + \eta_{S_h} S) & \text{for } h \text{ in } set_u \end{cases} \tag{3.6}$$

Again, this initial model does not use the strategic curtailment strategy. This strategy is introduced into the model in Section 3.3.

3.1.2 Lifetime (Financial) Model

The lifetime (or financial) model uses the outputs of the annual model to generate the levelized cost of hydrogen, $LCOH$. The $LCOH$ is the sum of all discounted cashflows divided by the sum of the discounted hydrogen production over the lifetime of the project. More simply, it is the price required for the project to break-even.

$$\text{LCOH} = \frac{\text{Discounted Cashflows}}{\text{Discounted Hydrogen Production}} = \text{Break Even Price}$$

The cashflows include the grid revenues and grid costs from the annual model. Newly introduced cashflows include capital expenditures, operational expenditures, taxes, and production tax credits.

Hydrogen production is a direct output of the annual model. It is assumed that the annual hydrogen production is repeated each year for the lifetime of the project.

A project time span begins 5 years prior to commercial operation declaration (COD) and ends 30 years after. All discounts are relative to COD, y = 0. Infrastructure is built in years $y = -4$ through $y = 0$, and hydrogen production occurs in years $y = 1$ through $y = 30$. Production tax credits apply only in years $y = 1$ through $y = 10$.

Lifetime Hydrogen Production

Assuming a discount rate of r, the discounted lifetime hydrogen production, $H_{2_{DL}}$, may be solved as follows.

$$H_{2_{DL}} = \sum_{y=1}^{30} \frac{H_{2_y}}{(1+r)^y} \tag{3.7}$$

Lifetime Grid Revenues and Costs

Similarly, the discounted lifetime grid revenues and costs are as follows.

$$R_{grid_{DL}} = \sum_{y=1}^{30} \frac{R_{grid_y}}{(1+r)^y} \tag{3.8}$$

$$C_{grid_{DL}} = \sum_{y=1}^{30} \frac{C_{grid_y}}{(1+r)^y} \tag{3.9}$$

Lifetime Capital Expenditures

The major capital expenditures, $CapEx$, include infrastructure costs from the wind farm, solar farm, and electrolyzer. The gross capital expenditure is calculated as follows.

$$CapEx = (CapEx_W * W + CapEx_S * S + CapEx_Z * Z) \tag{3.10}$$

Infrastructure costs are incurred in different proportions in the years leading up to COD. For example, if infrastructure takes 3 years to develop, the first year may require half of the total funds, and the last two years may each require a quarter of the total funds. Mathematically, the portions of the total capital cost each year are represented by the spend curve, SC_y. Then, the discounted lifetime capital expenditures is calculated as follows.

$$\begin{aligned} CapEx_{DL} = \sum_{y=-4}^{0} (&CapEx_W * SC_{W_y} * W + CapEx_S * SC_{S_y} * S \\ &+ CapEx_Z * SC_{Z_y} * Z) \frac{1}{(1+r)^y} \end{aligned} \tag{3.11}$$

Lifetime Operational Expenditures

The major operational expenditures, $OpEx$, include costs from the wind farm, solar farm, and electrolyzer use.

$$OpEx_{DL} = \sum_{y=1}^{30} (OpEx_W * W + OpEx_S * S + OpEx_Z * Z) \frac{1}{(1+r)^y} \tag{3.12}$$

Lifetime Taxes

Taxes are incurred on the cashflows from operation and offset by the deprecation of infrastructure. Federal and state governments allow for modified accelerated cost recovery system (MACRS) depreciation, as opposed to typical linear depreciation. Note that due to accelerated depreciation, taxes are frequently negative (the government owes money to the project) instead of positive in early years of operation.

It is best to first define a net tax rate, t_{net}, as the combination of state and federal tax rates, t_s and t_f respectively. Note to simplify this study, the state tax rate is assumed to be constant across the entire US.

$$t_{net} = (t_s + (1 - t_s) * t_f) \tag{3.13}$$

Then the tax rate is applied to grid revenues and offset by grid costs, operational expenses, and depreciation each year. The proportion of assets depreciated each year is given by $MARCS_y$.

$$Taxes_{DL} = \sum_{y=1}^{30} \Big(R_{grid_y} - C_{grid_y} - OpEx_y - CapEx * MACRS_y \Big) t_{net} \frac{1}{(1+r)^y} \tag{3.14}$$

Lifetime Production Tax Credits

The federal government provides production tax credits (PTC) for the generation of renewable energy and green hydrogen during the first ten years after COD. These are used to further offset taxes.

$$PTC_{DL} = \sum_{y=1}^{10} (PTC_W * E_{W_y} + PTC_S * E_{S_y} + PTC_Z * H_{2_y}) \frac{1}{(1+r)^y} \tag{3.15}$$

Levelized Cost of Hydrogen

Bringing it all together, the $LCOH$ may be calculated by summing all the discounted costs offset by the discounted revenues and PTCs, divided by the discounted hydrogen production.[1]

$$LCOH = \frac{C_{grid_{DL}} + CapEx_{DL} + OpEx_{DL} + Taxes_{DL} - R_{grid_{DL}} - PTC_{DL}}{H_{2_{DL}}} \tag{3.16}$$

3.2 Simplifying the LCOH Function

While the intuitive approach is useful for understanding green hydrogen plant mechanics, it does little in the way of improving our understanding of the mathematical function of $LCOH$. This section mathematically combines and simplifies terms. It also lays the groundwork for optimization methods in the next section.

[1]To meet the "break even price" definition for $LCOH$, the expression needs to be adjusted for taxes on the sale of hydrogen. To make this adjustment, simplify divide the expression by $1 - t_{net}$. For simplicity, this paper uses the definition that is not adjusted for taxes.

Annual Energy Generation

The annual wind energy generation, E_{W_y}, and solar energy generation, E_{S_y}, may be simplified using the average net capacity factor. Equations 3.1 and 3.2 reduce to the following.

$$E_{W_y} = 8760 * W * \eta_{W_{avg}} \tag{3.17}$$

$$E_{S_y} = 8760 * S * \eta_{S_{avg}} \tag{3.18}$$

Annual Hydrogen Production

Recalling the classification of overproduction hours as set_o and underproduction hours as set_u, we may define several new terms to help simplify the hydrogen production expression. These terms allow us to define the $LCOH$ function without the numerous sums and conditional statements.

First, let H_W represent the sum of all wind net capacity factors in which energy is overproduced[2], and let H_W^* represent the sum of all wind net capacities in which energy is underproduced.

$$H_W = \sum_{set_o} \eta_{W_h}$$

$$H_W^* = \sum_{set_u} \eta_{W_h}$$

Similarly, the terms for solar net capacity factors may be defined as H_S for overproduction hours[3] and H_S^* for underproduction hours.

$$H_S = \sum_{set_o} \eta_{S_h}$$

[2]This term is not used in the final expression for LCOH, but is defined for the sake of logical completion

[3]See footnote 2

$$H_S^* = \sum_{set_u} \eta_{S_h}$$

Next, let H_Z be the sum of all overproduction hours and H_Z^* be the sum of all underproduction hours.[4]

$$H_Z = \sum_{set_o} \eta_{Z_h}$$

$$H_Z^* = \sum_{set_u} \eta_{Z_h}$$

Using these new definitions, it is possible to rewrite the hourly matching hydrogen production expression, 3.4, as the following.

$$\text{Hourly: } H_{2_y} = \frac{H_Z Z + H_W^* W + H_S^* S}{SEC_Z} \tag{3.19}$$

The annual matching expression, 3.3, also changes using the term for average electrolyzer target throttle, $\eta_{Z_{avg}}$.

$$\text{Annual: } H_{2_y} = 8760 \frac{\eta_{Z_{avg}} Z}{SEC_Z} \tag{3.20}$$

Annual Grid Revenue and Costs

We may redefine grid revenue and costs in a similar fashion to hydrogen production.

First, let L_W represent the sum of the product of wind net capacity factor and power price for each hour in which energy is overproduced, and let L_W^* represent the same for each hour in which energy is underproduced.

$$L_W = \sum_{set_o} LMP_h * \eta_{W_h}$$

[4]See footnote 2

$$L_W^* = \sum_{set_u} LMP_h * \eta_{W_h}$$

Similarly, let the terms for solar be defined as L_S for overproduction hours and L_S^* for underproduction hours.

$$L_S = \sum_{set_o} LMP_h * \eta_{S_h}$$

$$L_S^* = \sum_{set_u} LMP_h * \eta_{S_h}$$

Finally, the terms for the electrolyzer be defined as L_Z for overproduction hours and L_Z^* for underproduction hours.

$$L_Z = \sum_{set_o} LMP_h * \eta_{Z_h}$$

$$L_Z^* = \sum_{set_u} LMP_h * \eta_{Z_h}$$

Using these new terms, we may redefine the annual grid revenue equation, 3.5, and annual grid costs equation, 3.6, as the following.

$$R_{grid_y} = L_W W + L_S S - L_Z Z \tag{3.21}$$

$$C_{grid_y} = -L_W^* W - L_S^* S + L_Z^* Z \tag{3.22}$$

Lifetime Hydrogen Production

As the annual hydrogen production is independent of the year, it is helpful to breakout the discounted lifetime sum factor, DL_{30}.

$$DL_{30} = \sum_{y=1}^{30} \frac{1}{(1+r)^y} \tag{3.23}$$

Then the equation for discounted lifetime hydrogen production, 3.7, reduces to the following.

$$\text{Hourly matching: } H_{2_{DL}} = \frac{H_Z Z + H_W^* W + H_S^* S}{SEC_Z} DL_{30} \tag{3.24}$$

$$\text{Annual matching: } H_{2_{DL}} = 8760 \frac{\eta_{Z_{avg}} Z}{SEC_Z} DL_{30} \tag{3.25}$$

Lifetime Grid Revenue and Costs

Using the same approach for liftime hydrogen production, the equations for lifetime grid revenues and costs, 3.8 and 3.9 respectively, reduce to the following.

$$R_{grid_{DL}} = (L_W W + L_S S - L_Z Z) * DL_{30} \tag{3.26}$$

$$C_{grid_{DL}} = (-L_W^* W - L_S^* S + L_Z^* Z) * DL_{30} \tag{3.27}$$

Lifetime Capital Expenditures

The capital expenditures expressions may be simplified by introducing a new discounted lifetime sum factors for the spend curves, SC_{DL}.

$$SC_{DL} = \sum_{y=-4}^{0} SC_{y} \frac{1}{(1+r)^{y}} \tag{3.28}$$

Using this new term, the lifetime capital expenditures expression, 3.11, reduces to the following:

$$\begin{aligned} CapEx_{DL} = (&CapEx_W * SC_{W_{DL}} * W \\ &+ CapEx_S * SC_{S_{DL}} * S \\ &+ CapEx_Z * SC_{Z_{DL}} * Z) \end{aligned} \tag{3.29}$$

Lifetime Operating Expenses

Using the DL_{30} term defined above, the discounted lifetime operating expense expression, 3.12, reduces to the following.

$$OpEx_{DL} = (OpEx_W * W + OpEx_S * S + OpEx_Z * Z)DL_{30} \tag{3.30}$$

Lifetime Taxes

The equation for discounted lifetime taxes may be reduced using the DL_{30} term and a new term for the discounted sum of MACRS depreciation, $MACRS_{DL}$.

$$MACRS_{DL} = \sum_{y=1}^{30} MACRS_{y} \frac{1}{(1+r)^{y}} \tag{3.31}$$

Using these terms, the equation for discounted lifetime taxes, 3.14, reduces to the following.

$$\begin{aligned}Taxes_{DL} = \Big(&\big(L_W + L_W^* - OpEx_W - CapEx_W * MACRS_{DL}\big)W \\ &+ \big(L_S + L_S^* - OpEx_S - CapEx_S * MACRS_{DL}\big)S \\ &+ \big(-L_Z - L_Z^* - OpEx_Z - CapEx_Z * MACRS_{DL}\big)Z\Big)t_{net}\end{aligned} \tag{3.32}$$

Lifetime Production Tax Credits

Another discounted lifetime sum factor, DL_{10}, may be introduced to simplify the equations for production tax credits.

$$DL_{10} = \sum_{y=1}^{10} \frac{1}{(1+r)^y} \tag{3.33}$$

Using this term, the expression for discounted lifetime production tax credits, 3.15, reduces to the following.

$$\begin{aligned}\text{Hourly matching: } PTC_{DL} = &\\ &\Big(PTC_W * (8760 * W * \eta_{W_{avg}}) \\ &+ PTC_S * (8760 * S * \eta_{S_{avg}}) \\ &+ PTC_Z * \left(\frac{H_Z * Z + H_W^* * W + H_S^* * S}{SEC_Z}\right)\Big) * DL_{10}\end{aligned} \tag{3.34}$$

Annual matching: $PTC_{DL} =$

$$\left(PTC_W * (8760 * W * \eta_{W_{avg}}) + PTC_S * (8760 * S * \eta_{S_{avg}}) + PTC_Z * \left(8760 \frac{\eta_{Z_{avg}} Z}{SEC_Z}\right)\right) * DL_{10} \quad (3.35)$$

Levelized Cost of Hydrogen

As a reminder, the expression for levelized cost of hydrogen, 3.16, is copied below.

$$LCOH = \frac{C_{grid_{DL}} + CapEx_{DL} + OpEx_{DL} + Taxes_{DL} - R_{grid_{DL}} - PTC_{DL}}{H_{2_{DL}}}$$

To arrive at the final simplified expression for $LCOH$, terms which are independent of overproduction/underproduction status each hour should be isolated. As these terms are independent of hour, they are constants, neither a function of W or S. These terms all occur in the numerator of the $LCOH$ function. Let C_W represent terms that scale directly with W, C_S represent terms that scale directly with S, and C_Z represent terms that scale directly with Z.

$$C_W = CapEx_W * (SC_{W_{DL}} - MARCRS_{DL} * t_{net}) + OpEx_W * DL_{30}(1 - t_{net}) - PTC_W * 8760 * \eta_{W_{avg}} * DL_{30}$$

$$C_S = CapEx_S * (SC_{S_{DL}} - MARCRS_{DL} * t_{net}) + OpEx_S * DL_{30}(1 - t_{net}) - PTC_S * 8760 * \eta_{S_{avg}} * DL_{30}$$

$$C_Z = CapEx_Z * (SC_{Z_{DL}} - MARCRS_{DL} * t_{net}) + OpEx_Z * DL_{30}(1 - t_{net})$$

The remaining terms in the numerator are all dependent on overproduction/underproduction status each hour. These condense to the following.[5]

$$-DL_{30}(1 - t_{net})\big((L_W + L_W^*)W + (L_S + L_S^*)S - (L_Z + L_Z^*)Z\big)$$

Finally, with these defined terms it is possible to rewrite the expression for $LCOH$ as the following:

Hourly matching:

$$LCOH = -PTC_Z \frac{DL_{10}}{DL_{30}} + \frac{C_W W + C_S S + C_Z Z - DL_{30}(1 - t_{net})(L_W W + L_S S - L_Z Z)}{\frac{DL_{30}}{SEC_Z}(H_Z Z + H_W^* W + H_S^* S)} \tag{3.36}$$

Annual matching:

$$LCOH = -PTC_Z \frac{DL_{10}}{DL_{30}} + \frac{C_W W + C_S S + C_Z Z - DL_{30}(1 - t_{net})\big((L_W + L_W^*)W + (L_S + L_S^*)S - (L_Z + L_Z^*)Z\big)}{8760 DL_{30} \frac{\eta_{Z_{avg}} Z}{SEC_Z}} \tag{3.37}$$

[5]The hydrogen production tax credit terms are not listed here because they may be pulled out of the fraction in the final expression

3.3 Modeling Strategic Curtailment Strategy

Introducing the strategic curtailment strategy directly into the expression for $LCOH$ is difficult because it is recursive. The curtailment strike price is dictated by the $LCOH$, and in turn the $LCOH$ is dictated by the strike price. Computational methods are used to solve this issue.

3.3.1 Strategic Curtailment in the LCOH Function

Each hour, there is an option to either produce and sell hydrogen, or to sell generated power.[6] These options result in two possible revenues.

Sell hydrogen:

$$\text{Revenue} = \frac{\text{Power Generation}}{\text{Specific Energy Consumption}}(LCOH(1 - t_{net}) + PTC_Z)$$

Sell power:

$$\text{Revenue} = \text{Power Generation} * LMP_h(1 - t_{net})$$

The strike price is the power price (LMP_h) where the marginal revenue from selling hydrogen is equal to the marginal revenue from selling power. Thus, the strike price may be defined as follows.

$$P_{strike} = \frac{LCOH + \frac{PTC_Z}{1-t_{net}}}{\text{Specific Energy Consumption}} \tag{3.38}$$

[6] In the case of annual matching, you also have the option to not purchase power. This also includes avoiding fees. When assessing annual cases, fees will be added to LMP_h. Strictly speaking, fees should only be assessed when avoiding the purchase of energy (not the sale of energy); however, it is assumed this will have negligible effects on the results

Using this strike price, it is possible to maximize the joint revenue from both hydrogen and energy. For power prices above the strike price, the electrolyzer will be curtailed down to 5% of its total capacity. Below the strike price, the electrolyzer will run at full capacity.[7]

$$\text{for } LMP_h > P_{strike}, \eta_{Z_h} = 5\%$$

$$\text{for } LMP_h \leq P_{strike}, \eta_{Z_h} = 100\%$$

3.3.2 Computational Methods for the Recursion

Now that the strike price is defined, it is possible implement the strategic curtailment strategy with the following steps.

1. Given the wind farm size (W), solar farm size (S), and electrolyzer size(Z), solve for the LCOH without a strike price (or $P_{strike} = \infty$).

2. Update the strike price using equation 3.38 and the $LCOH$ from the previous step.

3. Solve for the LCOH with the new strike price.

4. Repeat steps 2 and 3 until the difference between the strike price and LCOH is sufficiently small.[8]

[7] In Y = 10, the government stops granting production tax credits, meaning that the strike price will decrease. For simplicity, this study does not change the strike price at year 10, meaning that less curtailment than optimal will occur. Overall, this should be a relatively small effect, as we are already curtailing for extraordinarily large power prices and the curtailment in the first 10 years is more valuable than curtailment in the next set of years due to the time-value of money.

[8] In practice, the LCOH stop changing all-together after 5 iterations. This is because power prices in the dataset are discrete, not continuous. At a certain point, the new strike price no longer changes the curtailment hours and the LCOH and strike price remain constant with each iteration.

Note that with this strategy, it is impossible for the strike price to jump too low. Each successive update of strike price will be lower and lower, with the limit being $P_{strike} = LCOH$.

3.4 Optimization

As dictated in the objectives section, there are four cases of interest that I wish to explore. These are repeated below:

1. Green hydrogen plant design under ***hourly*** REC matching criteria
   (a) ***without*** strategic electrolyzer ***curtailment***.
   (b) ***with*** strategic electrolyzer ***curtailment***.
2. Green hydrogen plant design under ***annual*** REC matching criteria
   (a) ***without*** strategic electrolyzer ***curtailment***.
   (b) ***with*** strategic electrolyzer ***curtailment***.

First, I will give an overview of the constraints and optimization criteria for each case. Second, I will show how the system dimensionality may be reduced through the scalability. Finally, I will show the optimization methods used, namely mini-batch stochastic gradient descent.

3.4.1 Constraints

Each of these four cases exhibit different permutations of the following constraints: the edge constraints, the matching constraint, and the curtailment constraint.

Edge Case Constraints

All cases are subject a minimum and maximum constraint on wind and solar size. These constraints come into play when the green hydrogen plant solution is unbounded in a direction. A visual describing these constraints is shown in left-hand-side of Figure 3-1.

$$\text{Wind size constraint: } 0 \leq W \leq 5 \text{ MW} \tag{3.39}$$

$$\text{Solar size constraint: } 0 \leq S \leq 5 \text{ MW} \tag{3.40}$$

Matching Constraint

The matching constraint only pertains to annual matching. The hourly matching case does not require a constraint, as the hourly REC matching requirement is inherently followed in the equation 3.4. The matching constraint is as follows.

$$\text{Annual matching constraint: } \eta_{W_{avg}} W + \eta_{S_{avg}} S \geq \eta_{Z_{avg}} Z \tag{3.41}$$

Notice that this constraint may simply be illustrated as a line with intercepts at $W = \frac{Z}{\eta_{W_{avg}}}$ and $S = \frac{Z}{\eta_{S_{avg}}}$. To meet the constraint, the design, (W, S), simply must be above the line. Figure 3-1 compares the design space for hourly and annual matching, taking into account both the edge constraints and the matching constraint.

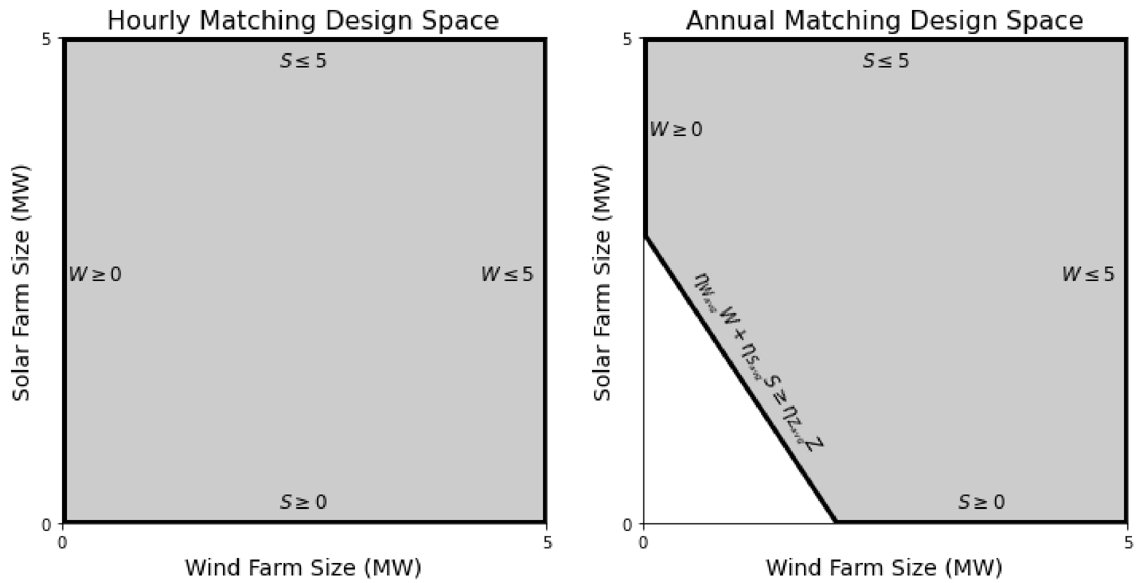

Figure 3-1: Design Space Comparison: Hourly vs Annual Matching Constraints

Curtailment Constraint

The curtailment constraint dictates the electrolyzer target throttle based on the current energy price. It is given by the following.

$$\text{Curtailment constraint: } \eta_{Z_h} = \begin{cases} 5\% & \text{for } LMP_h > P_{strike} \\ 100\% & \text{for } LMP_h \leq P_{strike} \end{cases} \tag{3.42}$$

For cases without the curtailment constraint, one should assume the electrolyzer target throttle is 100%.

3.4.2 Optimization Criteria by Case

Next, I will outline how each constraint is used in each case of interest.

Objective 1a: Hourly REC Matching

Hourly REC matching represents the base case. It is not subject to the matching or curtailment constraint, just the edge-case constraints. The electrolyzer throttle, eta_{Z_h}, is fixed at 100%.

$$\text{Hourly: } \min_{W,S,Z} LCOH \text{ subject to eq. 3.39 \& 3.40} \tag{3.43}$$

Objective 1b: Hourly REC Matching with Electrolyzer Curtailment

Hourly REC matching with curtailment introduces the curtailment constraint, 3.42, meaning the electrolyzer throttle may now toggle between 5% and 100%.

$$\text{Hourly with Curtailment: } \min_{W,S,Z} LCOH \text{ subject to eq. 3.42 \& 3.39 \& 3.40} \tag{3.44}$$

Objective 2a: Annual REC Matching

Annual REC matching introduces the matching constraint, 3.41. The electrolyzer throttle, eta_{Z_h}, is again fixed at 100%.

$$\text{Annual: } \min_{W,S,Z} LCOH \text{ subject to eq. 3.41 \& 3.39 \& 3.40} \tag{3.45}$$

Objective 2b: Annual REC Matching with Electrolyzer Curtailment

Finally, Annual REC matching with curtailment uses both the matching constraint, 3.41, and the curtailment constraint, 3.42. Again, the electrolyzer throttle may now toggle between 5% and 100%.

$$\text{Annual with Curtailment: } \min_{W,S,Z} LCOH \text{ subject to eq. 3.41 - 3.40} \tag{3.46}$$

3.4.3 Reducing System Dimensionality

The system is initially 4-dimensional. Wind size, solar size, and electrolyzer size represent the design variables. LCOH represents the dependent variable. However, the system described is completely scalable, meaning that if the required hydrogen production were to change, an existing design of wind, solar, and electrolyzer may be directly scaled in equal proportions to meet the new production level, without any change to LCOH. Thus, we may assume the electrolyzer size to be constant, and all derivatives with respect to electrolyzer size to be zero. This reduces the system to 3 dimensions: wind size, solar size, and LCOH.

3.4.4 System Derivatives

This section outlines the derivatives of the $LCOH$ with respect to the two design variables (after reducing dimensionality): wind farm size (W) and solar farm size (S).

Hourly

As a reminder, the equation for hourly LCOH , 3.36, is shown below.

$$LCOH = -PTC_Z \frac{DL_{10}}{DL_{30}} + \frac{C_W W + C_S S + C_Z Z - DL_{30}(1 - t_{net})(L_W W + L_S S - L_Z Z)}{\frac{DL_{30}}{SEC_Z}(H_Z Z + H_W^* W + H_S^* S)}$$

The derivatives are as follows:

$$\frac{dLCOH}{dW} = \Big(Z\big(H_Z C_W - H_W^* C_Z - DL_{30}(1-t_{net})(H_Z L_W + H_W^* L_Z)\big) + S\big(H_S^* C_W - H_W^* C_S + DL_{30}(1-t_{net})(H_W^* L_S - H_S^* L_W)\big)\Big) \div \left(\frac{DL_{30}}{SEC_Z}(H_Z Z + H_W^* W + H_S^* S)^2\right) \quad (3.47)$$

$$\frac{dLCOH}{dS} = \Big(Z\big(H_Z C_S - H_S^* C_Z - DL_{30}(1-t_{net})(H_Z L_S + H_S^* L_Z)\big) + W\big(H_W^* C_S - H_S^* C_W + DL_{30}(1-t_{net})(H_S^* L_W - H_W^* L_S)\big)\Big) \div \left(\frac{DL_{30}}{SEC_Z}(H_Z Z + H_S^* S + H_W^* W)^2\right) \quad (3.48)$$

Annual

As a reminder, the equation for annual LCOH , 3.37, is shown below.

$$LCOH = -PTC_Z \frac{DL_{10}}{DL_{30}} + \frac{C_W W + C_S S + C_Z Z - DL_{30}(1-t_{net})\big((L_W + L_W^*)W + (L_S + L_S^*)S - (L_Z + L_Z^*)Z\big)}{8760 DL_{30} \frac{\eta_{Z_{avg}} Z}{SEC_Z}}$$

The derivatives are as follows:

$$\frac{dLCOH}{dW} = \frac{C_W - DL_{30}(1-t_{net})(L_W + L_W^*)}{8760 DL_{30} \frac{\eta_{Z_{avg}} Z}{SEC_Z}} \quad (3.49)$$

$$\frac{dLCOH}{dS} = \frac{C_S - DL_{30}(1-t_{net})(L_S + L_S^*)}{8760 DL_{30} \frac{\eta_{Z_{avg}} Z}{SEC_Z}} \quad (3.50)$$

3.4.5 Optimization Methods

The optimization approach is applied to 2 million coordinates accross the U.S. Thus, it is imperative to find efficient optimization methods to reduce the computational expense of running each case.

In this section, I discuss the issue of function convexity, discuss potential optimization approaches, and finally outline the chosen optimization approach.

LCOH Function Convexity

The LCOH function was tested for convexity by observation. 48 coordinates were tested, one for each U.S. state. The LCOH was calculated over the entire design space shown in Figure 3-1 and 3-dimensional plot renderings we're used to visually test convexity. For hourly matching, convexity was seen for each of the 48 coordinates. Thus, I assumed convexity would hold for the rest of the U.S. For annual matching, convexity was observed for all coordinates when grid fees are in excess of \$15/MWh. Below \$15/MWh, some cases showed non-convex LCOH function shapes. This phenomena deserves further study, though it is not explored in this analysis. The result derived later in this thesis assume grid fees of \$20/MWh, and it is assumed convexity would hold at all coordinates in the U.S.

Choosing an Optimization Method

Three methods of optimization were explored: gradient decent, stochastic gradient decent, and mini batch gradient decent. All of these methods apply well to convex functions with no constraints (though constraints may be layered in, as discussed later on). Ultimately, mini batch gradient decent was chosen for its balance of robustness and speed.

Gradient decent (GD) is a well-known and robust optimization method that applies well to convex functions with no constraints. The procedure is straightforward: in each iteration the gradients of the function are calculated, then, a step is made in the gradient direction which lowers the objective function, and the process repeats. As this method uses the full dataset to calculate the gradients, its step direction is very accurate; however, it is also quite slow. Code runtime for all 2M coordinates under GD was approximately 2hr per iteration. [20] [19] [4]

Stochastic gradient decent (SGD) is very similar, but instead of using all of the dataset to calculate the gradients, only one randomly selected point is used. In the case of the green hydrogen plant, this translates to a single hour of the dataset being used to calculate the gradients (instead of four years of data). SGD is more advantageous than GD in in terms of speed (code runtime on the order of seconds per iteration), but the calculated gradients are quite inaccurate. The steps taken are often wild and in the wrong direction. Many coordinates do not converge on a solution. [20] [19] [4]

A balance of the two forms of optimization is mini batch gradient decent. Instead of using the full dataset or one randomly selected hour, a random sample of hours is used. In this case, it was found that a sample size of 10% of the data yielded robust gradients, with acceptable code runtime (around 6m per iteration). When testing 48 coordinates (of the 2M), it was found that a maximum of 40-50 iterations were needed to reach the optimal solution, resulting in a code which can easily complete overnight. [19] [4]

Mini Batch Gradient Decent

Implementing mini batch GD is relatively straightforward.

1. **Choose initial conditions.**

2. **Randomly sample a set of hours from the data.** To hold true to the seasonality of a day, hours were sampled in 24-hour chunks starting each starting at 00:00 UTC.

3. **Calculate the LCOH and gradients** using the sample data and equations 3.36-3.37, and 3.47 - 3.50.

4. **Step to the next condition using the gradients,** where n is the iteration number and α is the learning rate.[9]

$$W_{n+1} = W_n - \alpha\big(\frac{\partial LCOH}{\partial W}\big)_n$$

$$S_{n+1} = S_n - \alpha\big(\frac{\partial LCOH}{\partial W}\big)_n$$

5. **Enforce required constraints**

   (a) If using the matching constraint, eq. 3.41, one must ensure the (W, S) condition is above the matching constraint line. If the step forced the condition below the line, the condition should be moved to the nearest point on the line.

$$\text{If } S_n < -W_n \frac{\eta_{W_{avg}}}{\eta_{S_{avg}}} + \frac{Z}{\eta_{S_{avg}}},$$

$$\text{then } S_n^* = \frac{-W_n \eta_{W_{avg}} \eta_{S_{avg}} + S_n \eta_{W_{avg}}^2 + \eta_{S_{avg}} Z}{\eta_{S_{avg}}^2 + \eta_{W_{avg}}^2}$$

$$\& \; W_n^* = \frac{-S_n \eta_{S_{avg}} \eta_{W_{avg}} + W_n \eta_{S_{avg}}^2 + \eta_{W_{avg}} Z}{\eta_{W_{avg}}^2 + \eta_{S_{avg}}^2}$$

[9] The learning rate was chosen after a few experiments. A bigger learning rate may help the model converge more quickly, but could also result in an unstable model.

(b) Additionally, the minimum and maximum wind and solar size constraints must also be enforced. As these are unidimenional, they are easier to enforce. If the constraint is crossed, simply bring the violating condition back inside the design space.

6. **Update the strike price** using equation 3.38, if using the curtailment constraint 3.42.

7. **Repeat steps 2-5** until the change in $LCOH$ is sufficiently small between steps.

Chapter 4

Results

As introduced in the objectives section, results were generated for green hydrogen plants under four sets of conditions[1], relisted below. This chapter will briefly list some of the assumption used when analyzing the cases, present an overview of the results, explicitly test the research hypotheses, and finally discuss the rationale behind the findings. The next chapter will discuss the limitations of this research, potential future work, and present recommendations for stakeholders in the green hydrogen market.

Research Objectives:

1. Green hydrogen plant design under ***hourly*** REC matching criteria

   (a) ***without*** strategic electrolyzer ***curtailment***.

   (b) ***with*** strategic electrolyzer ***curtailment***.

[1] Note that cases 1b and 2b are not put through the optimization procedure discussed in 3.4.5. The wind and solar sizes from cases 1 and 2 are copied over when introducing the strike-price logic. Thus, results for wind and solar size for cases 1b and 2b are not shown, as they are simply a repeat of cases 1 and 2. While it is possible to re-optimize each coordinate using the curtailment logic, this method allows for a more direct comparison between cases with and without strategic curtailment.

2. Green hydrogen plant design under ***annual*** REC matching criteria

   (a) ***without*** strategic electrolyzer ***curtailment***.

   (b) ***with*** strategic electrolyzer ***curtailment***.

4.1 Assumptions

The following assumptions were used when generating results:

1. a discount rate of 10%.

2. a COD in 2031. All dollar amounts are 2031 dollars.

3. a constant electrolyzer capacity of 1 MW.

4.2 Overview

This overview sets the stage by highlighting key takeaways and fostering a common understanding before explicitly testing the hypotheses in the subsequent section. The plots provided aim to offer a broad comparison of hydrogen economics across the U.S., rather than pinpointing specific locations for infrastructure development. These plots are particularly useful for illustrating general trends and regional variations in hydrogen production costs.

To ensure clarity about the precision of the analysis, I use contour plots instead of continuous color plots. This choice underscores the coarse level of detail inherent in the study, suitable for macro-level insights rather than fine-grained analysis. Furthermore, the data presented has undergone spatial averaging of coordinates to smooth out extreme variations and present a more generalized view of the economic landscape.

4.2.1 Hourly

LCOH

The LCOH is generally reported in \$/kg, but the following plots normalize the cost to the price of gray hydrogen[2]. The hourly matching LCOH ranges from below 1.5 times the gray hydrogen price to above 4 times the gray hydrogen price. The cheapest areas to produce generally align with where wind resource is available, mainly in the Midwest and Texas regions. The most expensive area to produce is in the Pacific Northwest, followed by the Southeast. See figure 4-1.

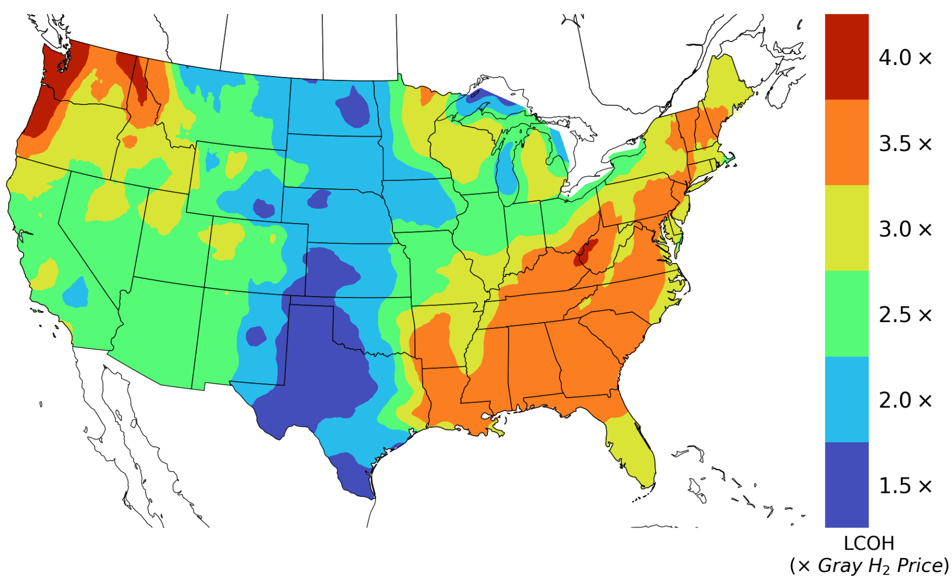

Figure 4-1: LCOH, Hourly Matching

[2]The price of gray hydrogen is assessed at \$2.13/kg [29]

Renewable Energy Mix

The renewable energy use varies amongst regions of the country. The midwest generally shows an even split of wind and solar capacity, with a slight inclination towards wind. The East and West regions are dominated by solar capacity, with some even mixes along ridge lines. The bulk of Texas has a 25-75 wind-solar mix. See figures 4-2, 4-3, 4-4.

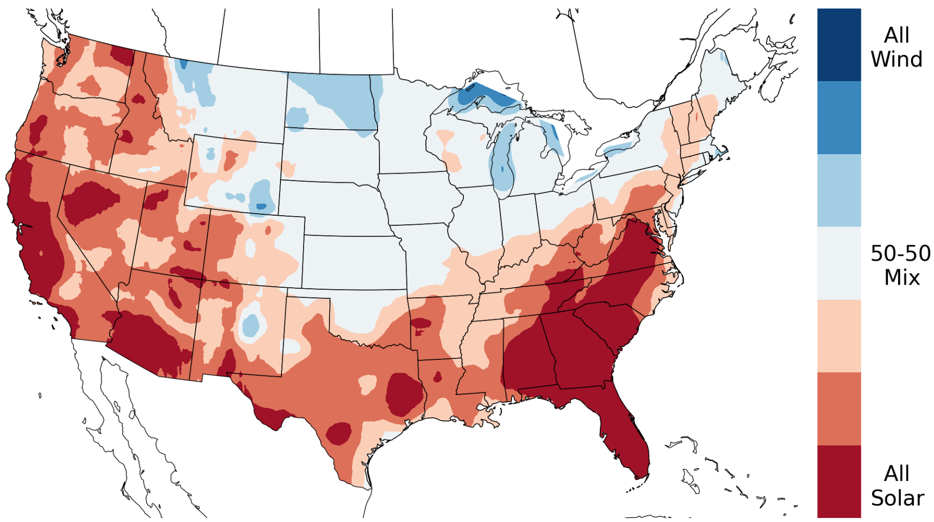

Figure 4-2: Renewable Energy Mix by Capacity, Hourly Matching

Savings from Strategic Curtailment

Like the LCOH, savings are reported in a normalized form relative to the price of gray hydrogen. Savings from strategic curtailment appear to be most concentrated in areas with high power price volatility (see Figure 2-7 for map of power price volatility). Texas shows the greatest amount of savings, above 12% of the price of gray hydrogen,

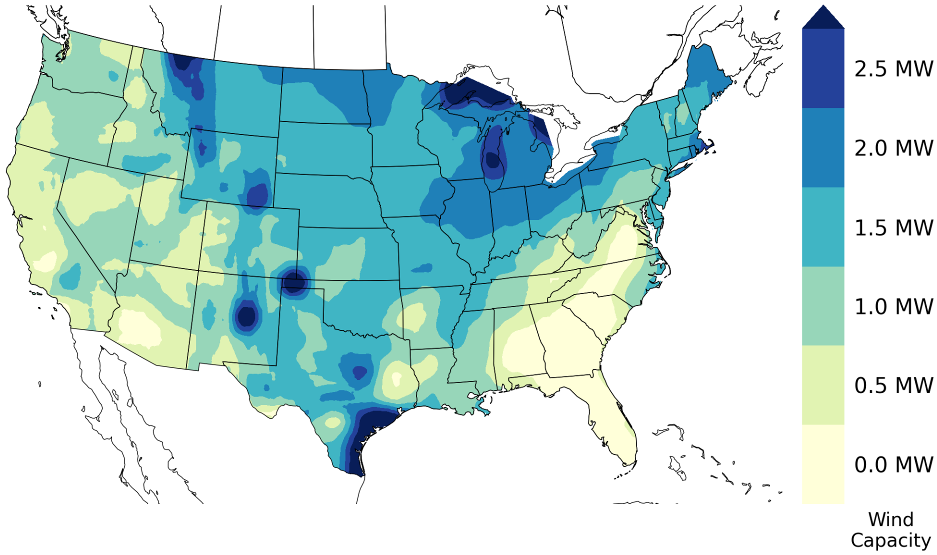

Figure 4-3: Wind Farm Size, Hourly Matching

followed by California and the greater New York City area. There are also noticeable dark green pocket scattered throughout the Midwest.

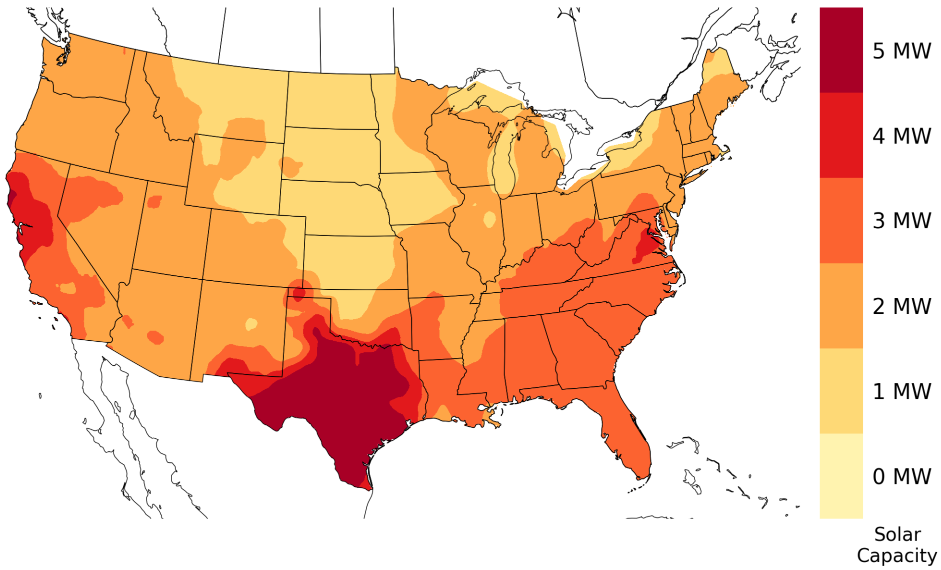

Figure 4-4: Solar Farm Size, Hourly Matching

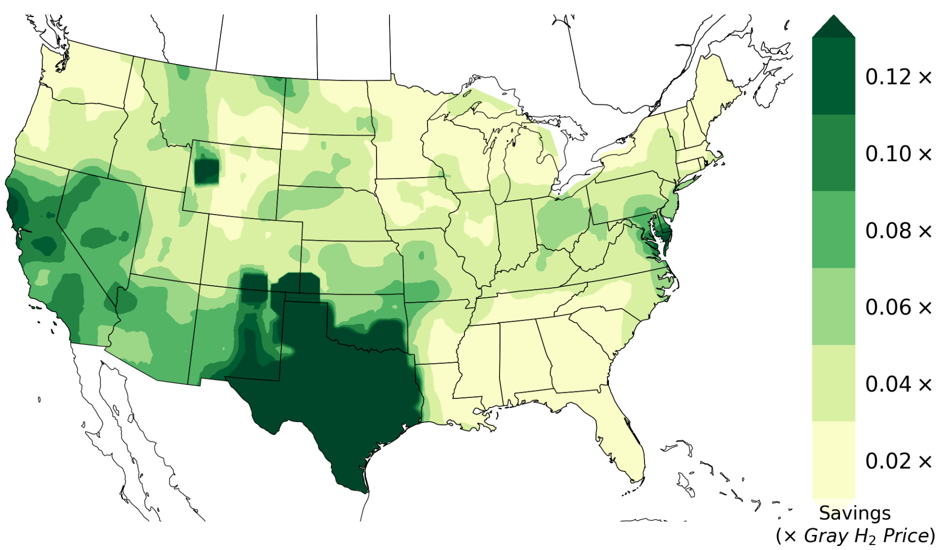

Figure 4-5: Savings from Strategic Curtailment, Hourly Matching

4.2.2 Annual

LCOH

Again, the LCOH is generally reported in \$/kg, but the following plots normalize the cost to the price of gray hydrogen[3]. The annual matching LCOH is much less than hourly matching. It ranges from below 1.3 times the price of gray hydrogen to above 1.8 times the price of gray hydrogen. The cheapest areas to produce still align with where wind resource is available, mainly in the Midwest and Texas regions, though notably even these regions appear to have significant solar usage. The most expensive areas to produce are in the Pacific Northwest and Northeast. The Southwest and Southeast regions rank in the middle. See figure 4-6.

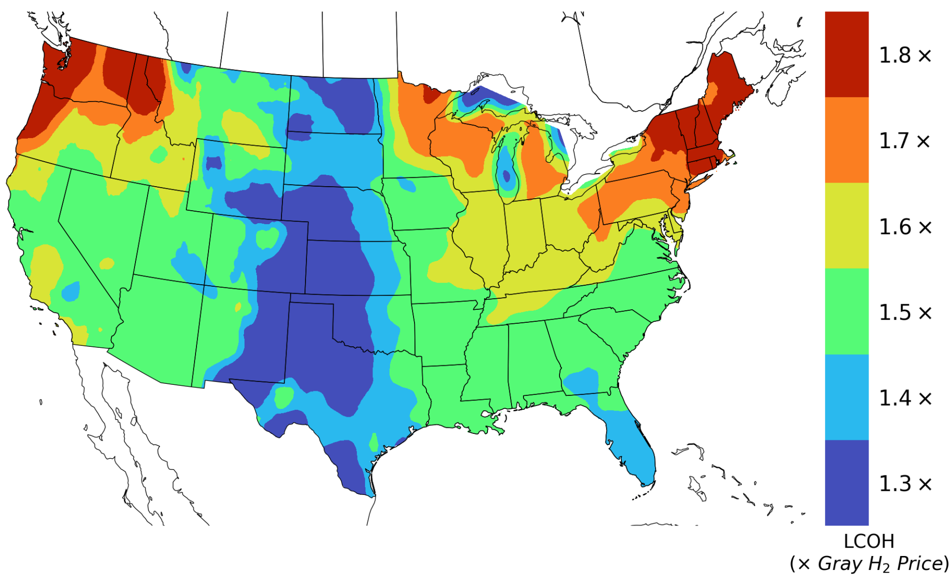

Figure 4-6: LCOH, Annual Matching

[3]The price of gray hydrogen is assessed at \$2.13/kg [29]

Renewable Energy Mix

The renewable energy capacity distribution is bimodal. Regions are dominated by either wind or solar generation, with few areas having a mix of the two. The bulk of the US has an all solar mix. The Midwest and Texas have a greater mix of wind and solar. Finally, the Northern Midwest Region favors all wind. See figures 4-7, 4-8, 4-9.

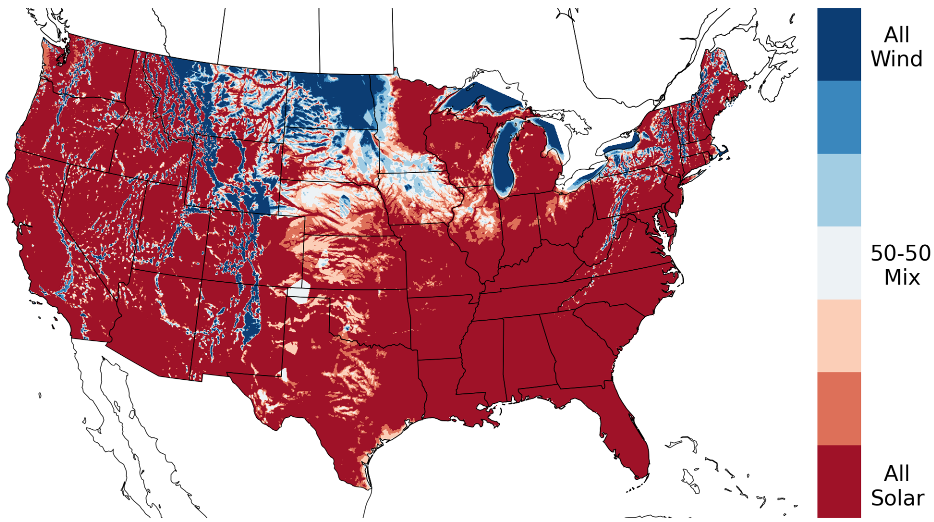

Figure 4-7: Renewable Energy Mix by Capacity, Annual Matching

Savings from Strategic Curtailment

The savings from strategic curtailment are greater for annual matching, compared to hourly matching. Savings range from zero to above 18% of the price of gray hydrogen. Again, savings from strategic curtailment appear to be most concentrated in areas marked by high power price volatility (see figure 2-7 for map of power price volatility).

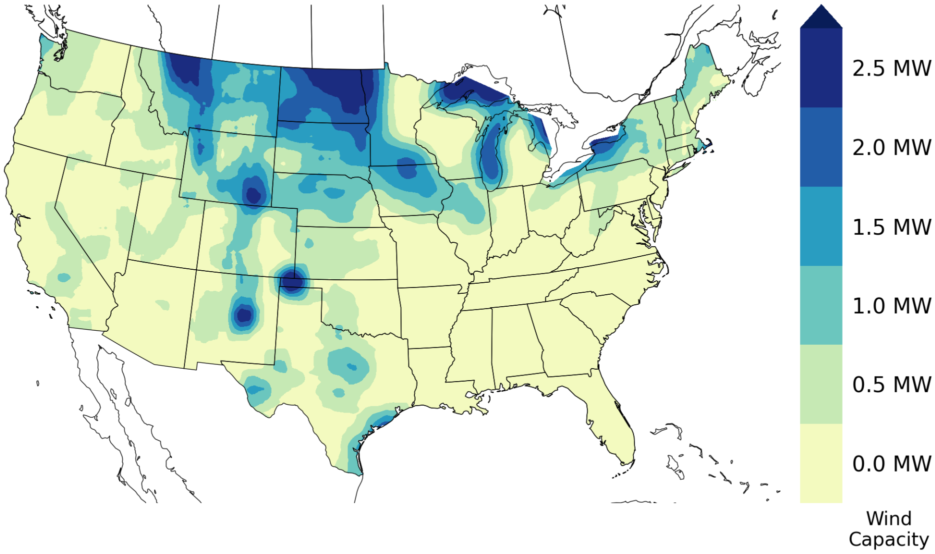

Figure 4-8: Wind Farm Size, Annual Matching

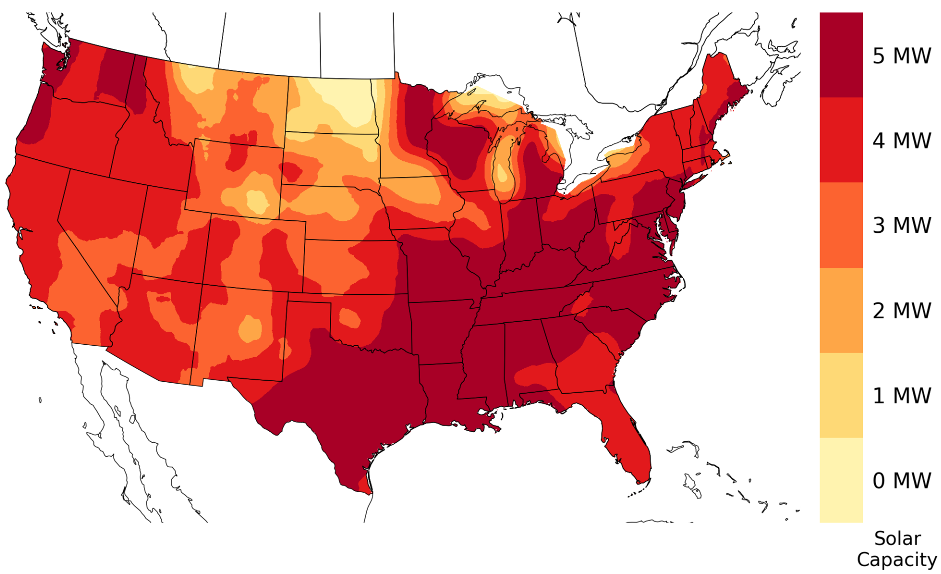

Figure 4-9: Solar Farm Size, Annual Matching

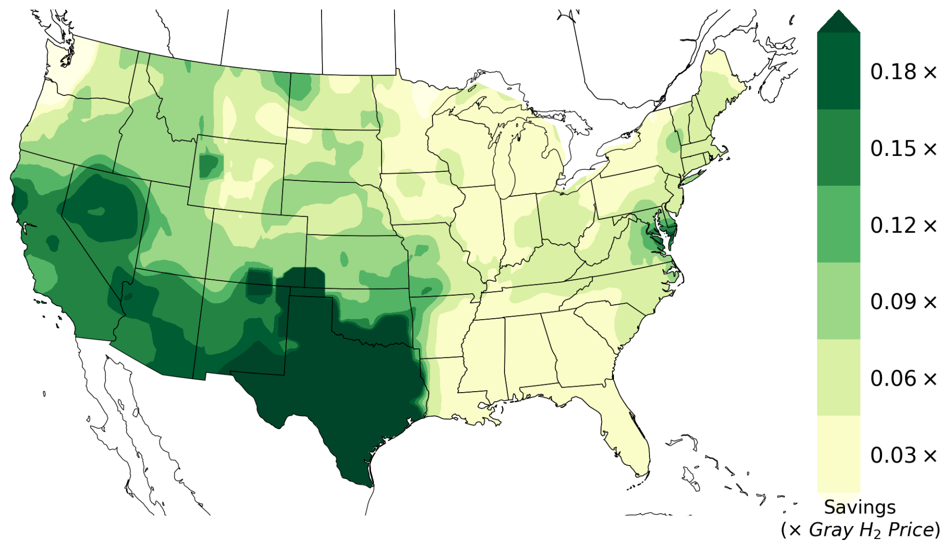

Figure 4-10: Savings from Strategic Curtailment, Annual Matching

4.3 Hypothesis Testing

The hypotheses laid out in the objectives section are relisted below. This section will systematically test each hypothesis and provide brief explanations for the results. A more in-depth discussion is provided in the next section.

Hypotheses:

1. **Green hydrogen production cost:**

    (a) **Under annual REC matching**, more than 10% of geographic locations in the U.S. may produce green hydrogen at cost parity with gray hydrogen[4].

    (b) **Under hourly REC matching**, less than 2% of geographic locations in the U.S. may produce green hydrogen at cost parity with gray hydrogen

2. **The value of annual matching over hourly matching constraints** exceeds half the price of gray hydrogen. The difference in production costs will be assessed at the median LCOH for all geographic locations in the U.S.

3. **Renewable energy composition:**

    (a) **Hourly REC matching** is predicted to lead to a higher adoption of wind energy solutions than annual matching; a higher adoption of hybrid (wind and solar) energy solutions than annual matching; and a lesser adoption of all solar energy solutions than annual matching.

    (b) **Annual REC matching** is predicted to favor homogeneous energy solutions (either all-wind or all-solar).

4. **Strategic electrolyzer curtailment effects:** Strategic electrolyzer curtailment will reduce the cost of green hydrogen across all scenarios, irrespective

[4]The price of gray hydrogen is assessed at $2.13/kg [29]

of the REC matching requirement or geographic location. However, the cost reduction will be most pronounced under annual REC matching conditions and in regions characterized by high electricity price volatility.

4.3.1 Hypothesis 1: Green Hydrogen Production Cost

Figure 4-11 shows the distribution of LCOH for both hourly and annual matching. It is clear from the distribution that annual matching is cheaper than hourly matching overall. Much of this may me attributed to the more effective use of electrolyzer infrastructure under annual matching. As annually matching does not require frequent interruptions to hydrogen production, a greater quantity of hydrogen is produced for an electrolyzer of the same size. Thus, the overall cost of hydrogen is reduced under annual matching.

To test Hypothesis 1, the LCOH must be compared to conventional gray hydrogen, assessed at $2.13. Under hourly matching, a significant portion of the U.S. falls into the cost competitive range with gray hydrogen; however, only 2% reach parity with the mean cost of gray hydrogen. Under hourly matching, very few regions fall into the cost competitive range with gray hydrogen.

Hypothesis 1a Conclusion: Fail Only 2% of the U.S. reaches cost parity with gray hydrogen. Additionally, most of the solutions which reach cost parity are in the geographically restrictive areas such as the great lakes. This limitation is further discussed in Section 5.1.1.

Hypothesis 1b Conclusion: Pass Less than 1% of the U.S. reaches cost parity with gray hydrogen.

This assessment is concerning, as it is clear that green hydrogen will have difficultly establishing itself in the general hydrogen market under the current economics. The market must change, either through government policy or technological breakthrough, for green hydrogen to effectively compete against gray hydrogen.

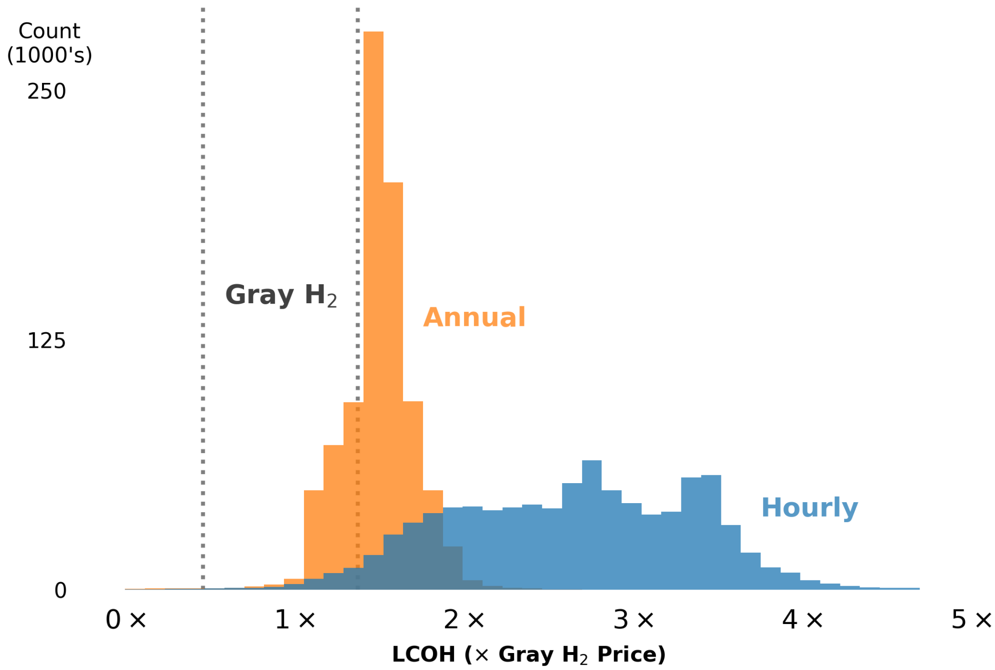

Figure 4-11: LCOH Distribution, Hourly vs Annual

4.3.2 Hypothesis 2: Value of Annual vs Hourly Matching

Looking at the distribution of annual and hourly costs, it is clear that annual has a significant advantage. When comparing medians, annually matched cases cheaper than hourly matched cases by amount equal to 1.1 times the gray hydrogen price. However, there is also a significant difference in the spread of each distribution, meaning that this advantage does not have the same dollar value for all locations. Again, reference Figure 4-11.

It is unlikely that half of the U.S. will be suitable for green hydrogen production. Naturally, production will only occur in the cheapest areas until green hydrogen demand is met. Thus, instead of comparing median LCOHs, it makes more sense to compare values for a smaller subset, perhaps the cheapest 10% of geographic locations. When comparing the lowest decile of coordinates, the advantage of annual over hourly is smaller, though still significant, at an amount equal to 0.4 times the gray hydrogen price. Thus, as we constrain green hydrogen production to the most economic locations, the value of annual matching over hourly matching begins to diminish.

Hypothesis 2 Conclusion: Pass The value of annual matching over hourly matching constraints is equal to 1.1 times the gray hydrogen price, assessed at the median. This represents a highly significant difference in economics between the two REC matching types. However, this advantage lessens as we consider only the most economic locations for green hydrogen production.

4.3.3 Hypothesis 3: Renewable Energy Composition

Figure 4-12 shows a 2D distribution of renewable energy compositions under hourly matching. As a reminder, it may be helpful to reference the overall design space for the analysis, shown previously in Figure 3-1. Note that new figure below is on a log-scale. It shows the bulk of solutions in several areas:

1. Along the solar-axis. These represent all-solar, zero-wind solutions.
2. Along the solar = 5 MW line. These represent solutions unbound in the solar-size dimension.
3. A roughly equal mix of wind and solar, centered around (wind = 1.75, solar = 1.75).

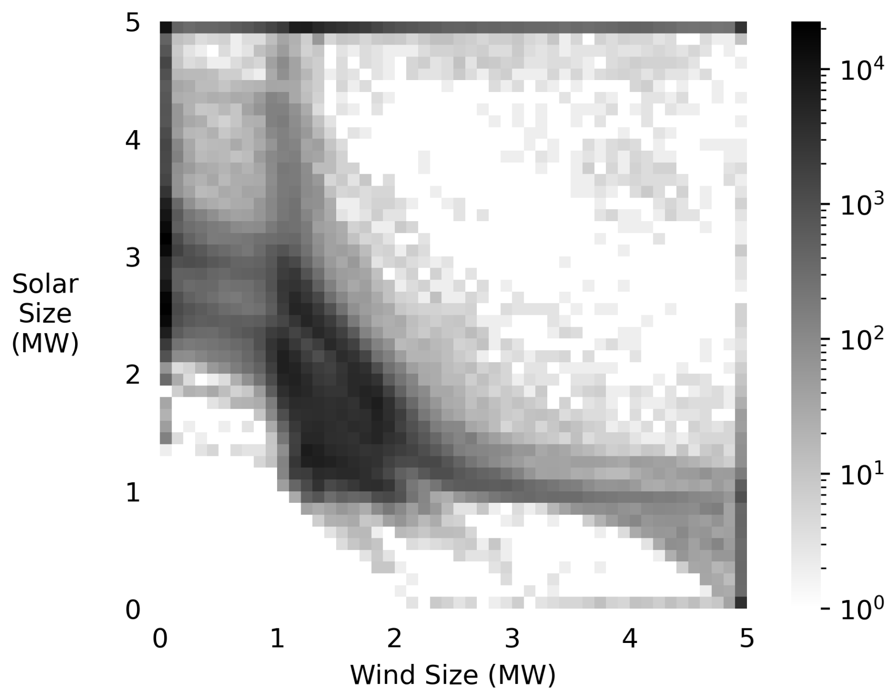

Figure 4-12: Renewable Energy Composition, Hourly

Figure 4-13 shows the 1D distribution of renewable energy composition as a percentage of total capacity. It is clear that the bulk of solutions are either all-solar or a hybrid of wind and solar.

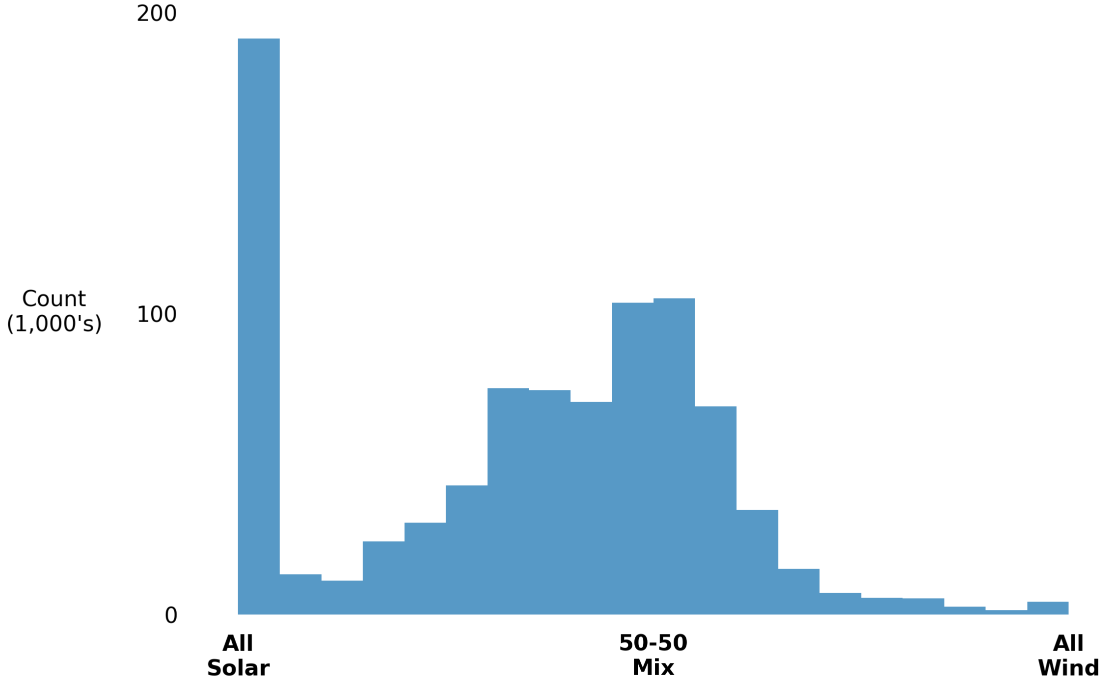

Figure 4-13: Renewable Energy Composition, Hourly

Figure 4-14 shows a 2D distribution of renewable energy compositions under annual matching. Again, note that the figure is on a log-scale. The bulk of solutions in several areas:

1. Along the solar-axis. These represent all-solar, zero-wind solutions.

2. Along the wind-axis. These represent all-wind, zero-solar solutions.

3. Along the solar = 5 MW line. These represent solutions unbound in the solar-size dimension.

4. Along a linearly downward sloping line. These represent solutions which run into the annual matching constraint line, as shown on the right-hand-side of Figure 3-1.

Figure 4-15 shows the 1D distribution of renewable energy composition as a percentage of total capacity. This distribution is bimodal: solutions are either all-solar or all-wind.

Thus overall, we confirm many of our previous notions about the effect of matching criteria on the choice of renewable energy technology. Under hourly matching, mixing renewable energy technologies presents a significant advantage. This is due to the general anti-correlation of power generations from wind farms and solar farms, as discussed in Section 2.1.3. Under annual matching, the advantage of mixed renewable energy technologies is abated and we see more homogeneous energy solutions.

Hypothesis 3a Conclusion: Partial Pass Hourly matching favors a hybrid mixture of wind and solar; not both hybrid mixtures and all-wind.

Hypothesis 3b Conclusion: Pass Hourly matching favors homogeneous energy generation. The distribution is bimodal: either all wind or all solar.

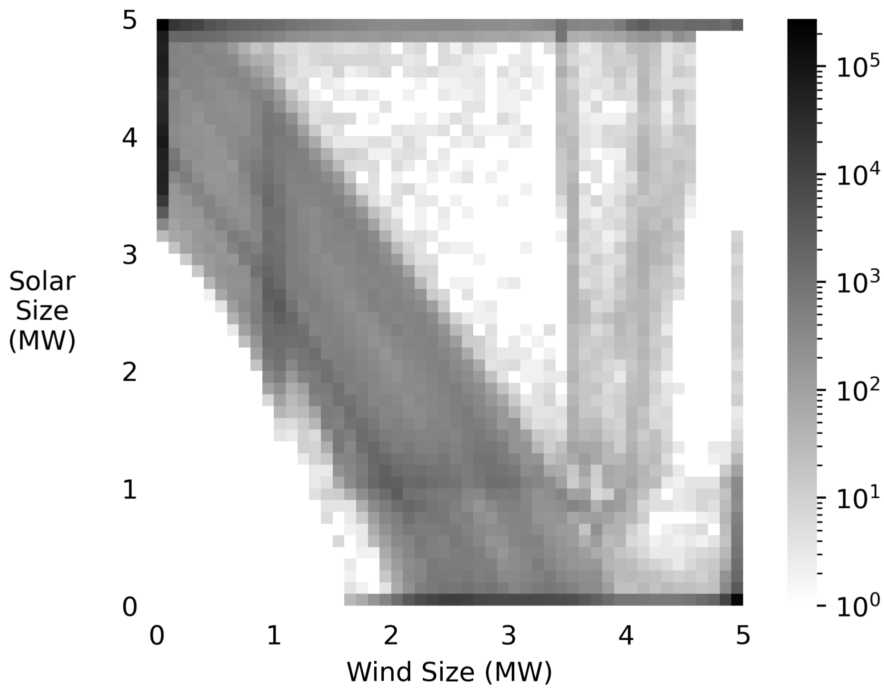

Figure 4-14: Renewable Energy Composition, Annual

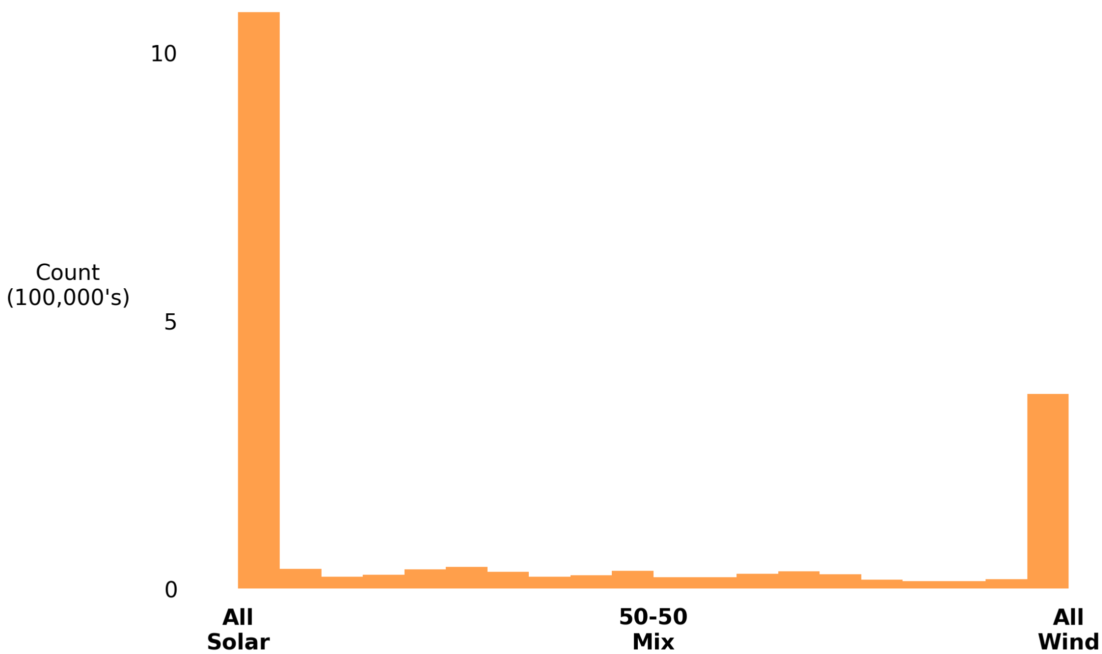

Figure 4-15: Renewable Energy Composition, Annual

4.3.4 Hypothesis 4: Strategic Electrolyzer Curtailment Effects

Figure 4-16 shows the savings resulting from strategic electrolyzer curtailment. For hourly matching, the bulk of the distribution is below 20% of the gray hydrogen cost, with a meaningful grouping of points with savings around 70% of the gray hydrogen cost. For annual matching, the bulk of the distribution is below 25%, again with a meaningful grouping of points with savings between around 70%.

These results align with expectations; however, it is interesting to see how some areas experienced significantly greater savings, northwards 70% of the gray hydrogen price, from strategic curtailment. These groupings are limited to a few geographic locations within Texas which experienced extreme power prices for significant periods, the most major event being Winter Storm Uri in 2021. This illustrates a great advantage of strategic electrolyzer curtailment: by building this strategy into the operations of a green hydrogen plant, one may capitalize on extreme events, effectively hedging against high power prices.

Hypothesis 4 Conclusion: Pass All cases show savings resulting from electrolyzer curtailment, but saving for annual matching are meaningfully greater than those for hourly matching.

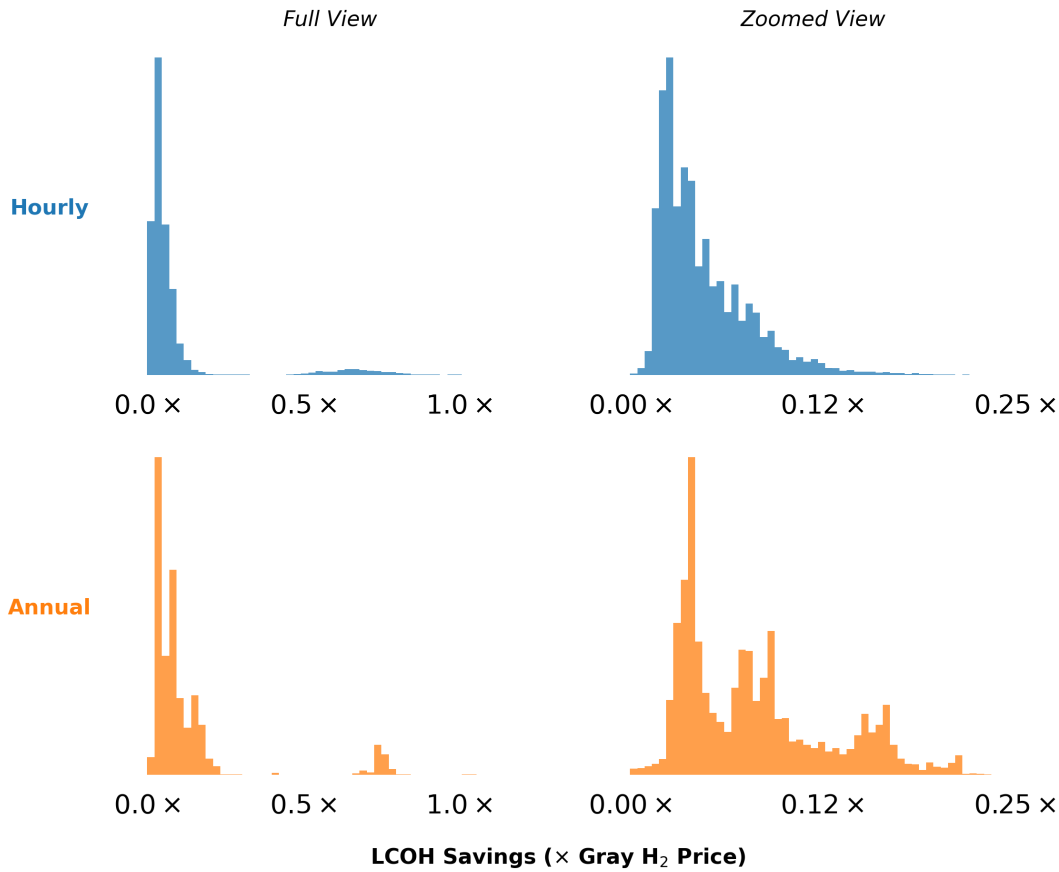

Figure 4-16: Savings from Electrolyzer Curtailment

4.4 Discussion

The analysis conducted in this thesis provides a comprehensive overview of the economic landscape for green hydrogen production across the U.S., exploring the intricacies of how policy and operational strategies can influence its viability. The findings reveal a nuanced picture of regional differences, cost implications, and the potential pathways to make green hydrogen a competitive alternative to traditional hydrogen sources.

4.4.1 Economic Landscape of Green Hydrogen

Our exploration into the economic feasibility of green hydrogen production has pinpointed the middle region of the U.S. as the most cost-effective area. This includes Texas, Oklahoma, Kansas, Nebraska, North Dakota, South Dakota, Eastern Colorado, and Eastern New Mexico. The middle region benefits from an abundance of renewable resources, with the northern part boasting high wind NCFs and the southern areas enjoying both high wind and solar NCFs. Texas, in particular, emerges as the most favorable state for green hydrogen production, attributed to its exceptional renewable energy potential.

Conversely, the Northeast and Northwest regions face challenges due to their lower wind and solar NCFs, positioning them as less attractive for green hydrogen production. The Southeast and Southwest, while not as prohibitive as the former regions, still present moderate production costs. Notably, the annual REC matching criteria bring a level of parity across regions, especially benefiting areas with strong solar resources due to the matching criteria's flexibility.

Despite these regional disparities, the overarching conclusion indicates major economic hurdles for green hydrogen production in competing with gray hydrogen, priced at approximately \$2.13/kg. This reality suggests that, in the near term, green hydrogen's market will likely be confined to entities motivated by sustainability goals rather than cost competitiveness alone.

4.4.2 REC Matching, Renewable Energy Mix, and the Geography of Viable Green Hydrogen Plants

As described before, a mix of both wind a solar technologies presents a great advantage under more stringent REC matching criteria due to the anti-correlation of the two resources. Thus, hourly matching greatly favors regions which have high wind and solar resources. This limits viable hydrogen production to a smaller portion of the U.S., mainly the middle region of the country.

Less stringent matching criteria lessen the advantage of mixing energy technologies, resulting in more homogeneous energy solutions. This effectively widens the viable regions for hydrogen production. Under annual matching, hydrogen production in the Southeast and Southwest are on more equal footing with the middle of the country. These areas have relatively high solar resource, but low wind resource, and benefit from the less stringent matching criteria. Thus, the choice of REC matching will shape the green hydrogen market beyond simple financials. It will also dictate where green hydrogen is produced in the U.S.

4.4.3 Strategic Curtailment Assessment

Strategic curtailment emerges as a critical tool in enhancing the economic attractiveness of green hydrogen, particularly in regions characterized by significant electricity price variability. Texas, once again, stands out as a prime location where strategic curtailment can yield substantial cost savings, potentially lowering green hydrogen production costs to parity with gray hydrogen under certain conditions. Notably though, all regions benefit from the strategy. This breakthrough indicates a path toward making green hydrogen cost-competitive with gray hydrogen, at least in specific geographic and market conditions.

This chapter has presented a detailed analysis of the economic viability and strategic benefits of green hydrogen production in various U.S. regions, under different REC matching criteria and the application of strategic curtailment. The investigation tested specific hypotheses related to production costs, renewable energy mix, and the impact of strategic curtailment, highlighting key findings such as the cost-effectiveness of certain regions, the influence of REC matching on renewable energy source selection, and the economic advantages of strategic operational adjustments. Moving forward, the next chapter will address the limitations of this research, suggest directions for future work, and offer recommendations to both policymakers and businesses involved in the green hydrogen market. This transition aims to build on the insights gained, exploring how they can inform more effective strategies and policies for the development of the green hydrogen sector.

Chapter 5

Conclusion

This thesis provides a comprehensive exploration of the nascent green hydrogen industry within the U.S., assessing its economic viability, the impact of public policies, and the strategic decisions businesses must navigate to thrive. Detailed analysis has revealed significant variations in regional production costs, primarily influenced by the availability of local renewable energy resources and existing infrastructure. The examination of REC matching criteria has underscored how different legislative frameworks—hourly versus annual—can significantly impact the economic feasibility of green hydrogen projects. Hourly matching, while more stringent, poses greater challenges for consistent energy supply, whereas annual matching offers more flexibility, thus potentially lowering operational costs in regions with variable renewable outputs.

Additionally, the strategic curtailment practices studied highlight the potential for significant cost reductions in energy-intensive operations, particularly in areas with high electricity price volatility. This adaptive management strategy has proven crucial in optimizing production costs and enhancing overall economic viability.

These insights collectively illuminate the path forward for green hydrogen as a critical component of the U.S.'s clean energy transition. As we conclude, it becomes imperative to distill these insights into actionable recommendations for policymakers and businesses alike, aiming to catalyze the growth of a green hydrogen economy that is both sustainable and economically viable. The following sections will recapitulate the key findings, discuss the limitations of the current research, and propose a set of targeted recommendations that could help overcome the identified barriers and capitalize on the opportunities within the green hydrogen sector.

5.1 Limitations of Current Work

This section acknowledges the constraints and assumptions that underlie the analysis presented in this thesis. Recognizing these limitations is crucial for interpreting the findings accurately and guiding future research.

5.1.1 Geographic Restrictions

The analysis identified regions along ridge lines with high wind resources as the most economically viable locations for hydrogen production. However, these areas often present significant construction challenges or are already occupied by existing wind farms, potentially limiting their practical utility for new green hydrogen projects. Additionally, the economic assessments suggested that the Great Lakes region could be favorable for hydrogen production. It's important to note that offshore wind and solar costs, which would be relevant for such water-covered areas, were not considered in the study. As a result, these regions might not accurately reflect viable options for green hydrogen production.

5.1.2 Power Markets Dynamics and the Influence of New Infrastructure

The study presupposes that the introduction of green hydrogen plants does not alter power market dynamics, an assumption that holds for small-scale projects. In reality, the addition of significant new load and generation capacity, particularly from large-scale hydrogen production facilities, could impact power prices and dispatch strategies within Independent System Operators (ISOs). Therefore, while the findings provide valuable insights for small projects, they may not fully apply as project scale increases, necessitating more complex analysis of power market dynamics.

5.1.3 Power Market Historical Behavior Does Not Indicate Future Behavior

Texas emerged as a leading region for cost-effective hydrogen production, largely due to high power price volatility driven by extreme weather events. However, ongoing reforms in Texas aim to stabilize the power market, potentially reducing the effectiveness of strategic curtailment strategies in the future. This highlights the importance of considering how market reforms and infrastructure improvements may change the landscape of green hydrogen production viability.

5.1.4 Lack of Power Price Data for Certain Regions of the U.S.

The power price data utilized in this research covers all major unregulated power markets but lacks information on regulated markets, particularly in the Southeast and near the Rocky Mountains. The analysis used proximate unregulated market prices as a stand-in for these regions, which may not accurately reflect their specific power market dynamics. Future studies would benefit from incorporating detailed power price data from these regulated markets to provide a more comprehensive overview.

5.1.5 Cost Assumptions

The research assumed uniformity in infrastructure costs, taxes, and did not account for the costs associated with electric transmission, hydrogen storage, or distribution/transportation. These factors can significantly influence the overall cost of hydrogen production (LCOH) and vary by region. It should also be noted that the cost assumptions used are for utility-scale projects- this somewhat contradicts the power market dynamics limitation which states that the assumptions hold for small-scale projects. Addressing these variables in future analyses will be essential for generating more precise estimates of green hydrogen production costs across different U.S. regions.

5.2 Future Work

The groundwork laid by this thesis invites further investigation into several areas that could refine and expand our understanding of green hydrogen's economic and operational landscape.

5.2.1 Sensitivity Studies

Future studies could explore the impact of various factors on green hydrogen's cost competitiveness. Questions such as the required reduction in electrolyzer costs or the implications of fluctuating renewable energy prices could provide valuable insights for policymakers and investors. These sensitivity analyses could help identify the most impactful levers to reduce green hydrogen production costs.

5.2.2 Analysis of Green Hydrogen Production Seasonality

The variability in green hydrogen production, especially under hourly matching or with strategic curtailment, raises questions about seasonality and its impact on production consistency. An in-depth analysis of how production might vary with seasons, and the implications for sales and customer contracts, would be a valuable area for future research.

5.2.3 Incorporating Hydrogen Storage into Design

Integrating hydrogen storage solutions could address production variability and ensure a steady supply of green hydrogen. Future research could assess the optimal size of storage systems needed to maintain consistent delivery schedules and how storage integration affects overall production costs.

5.2.4 Assessment of Other Matching Criteria

Expanding the scope of REC matching criteria to include daily or monthly options could potentially unlock new opportunities for solar-based solutions, particularly in the southern U.S. This exploration could reveal alternative strategies to enhance the viability of green hydrogen production across a broader range of geographic regions.

By addressing these areas, future work can build on the findings of this thesis to further study the potential of green hydrogen as a critical part of a sustainable energy future.

5.3 Recommendations

The findings of this thesis underscore the critical role of supportive policies and strategic business practices in advancing the green hydrogen sector.

5.3.1 Recommendations to Policy Makers

Increase the Green Hydrogen Production Tax Credit

To enhance the competitiveness of green hydrogen against gray hydrogen, it is crucial that policymakers consider adjustments to the PTC. For projects adhering to hourly REC matching, I propose an increase in the PTC from the current \$3/kg to approximately \$4.80/kg. This adjustment would enable at least 10% of the United States to produce green hydrogen at a viable cost. For those under annual REC matching, a more modest increase to \$3.50/kg is suggested. Similarly, this change aims to enable cost parity with gray hydrogen in 10% of locations. These estimates are likely lower than the actual required increase for cost parity with gray hydrogen, due to the limitations discussed in Section 5.1.5.

Alternatively, another strategy to further support the green hydrogen plants involves extending the duration of PTCs beyond the current ten-year limit. A decade of PTCs at \$3/kg effectively equates to \$1.96/kg over the lifespan of a project, assuming a 10% interest rate[1]. Thus, extending this duration could significantly enhance the financial feasibility of green hydrogen projects. This approach not only provides a longer-term financial incentive but also provides a more steady cashflow throughout the project, ensuring that green hydrogen projects are not abandoned part-way through their lifetime, and more consistent operations overall.

[1] Reference the first term on the right-hand-side of the LCOH equations, 3.36 and 3.37

Allow Annual REC Matching for Projects which Commence Operations Prior to the End of 2032

In response to the U.S. Department of Treasury's announcement in December 2023, which set hourly REC matching as the standard for green hydrogen projects, with a transition period allowing annual matching only until 2028 [32], I propose an alternative approach. To more effectively support the development of the green hydrogen sector, all hydrogen projects that commence operations before the year of 2032 should be permitted to have 10 years of annual matching. Projects initiated post-2032 should then adhere to the hourly REC matching requirements. Given that green hydrogen projects take about 5 years to develop, this allows for a 2.5 year period where green hydrogen projects may commence operations and benefit from a lifetime of less stringent matching requirements. Additionally, these projects will not have to deal the complication of swapping matching requirements part-way through their lifetime, complicating its planned operations.

These initial projects may pave the way for future ones by jump-starting the economies of scale associated with electrolyzer manufacturing, and establishing a green hydrogen economy within the U.S. Thus, these pioneering projects may reduce barriers to entry for the subsequent hourly-matched projects, fostering a more robust and economically viable green hydrogen industry.

5.3.2 Recommendations to Businesses

Build in the Middle Regions of the U.S., Especially Texas

The economic analysis clearly identifies the middle regions of the U.S. as prime locations for green hydrogen projects, thanks to their abundant renewable resources. It is recommended that development efforts be concentrated in these areas, especially in Texas, to capitalize on their favorable conditions for green hydrogen production. Furthermore, concentrating green hydrogen projects in one region could foster synergies between separate initiatives, enabling shared supply chain logistics, and collaborative use of infrastructure such as shared hydrogen storage and pipelines, thereby enhancing overall project viability and impact.

Use Strategic Curtailment

Strategic curtailment has emerged as a straightforward and effective strategy for reducing the LCOH. By adjusting operations in response to electricity price fluctuations, businesses can significantly lower operational costs. This approach is especially beneficial in regions experiencing high power price volatility, like Texas, where careful management of energy consumption can yield considerable savings. Employing strategic curtailment allows for more flexible and economically efficient green hydrogen production, optimizing the use of renewable energy sources and enhancing the overall feasibility of projects.

Negotiate with ISOs to Allow for Demand Response Payments

Negotiating with Independent System Operators (ISOs) to participate in demand response programs offers a lucrative opportunity for green hydrogen projects. Demand response, a system where electricity consumers are compensated for reducing their power usage during peak demand periods, can be effectively leveraged by green hydrogen facilities. During times when electricity demand outstrips supply, these projects can temporarily cease operations, particularly electrolysis processes, and redirect the unused electricity back to the grid. This action contributes to grid stability by balancing demand and supply, potentially lowering electricity prices. Engaging in demand response not only allows green hydrogen operations to earn payments from ISOs but also capitalizes on selling electricity at premium rates. This dual benefit underscores the strategic advantage of integrating green hydrogen projects within broader energy management and grid support frameworks, enhancing their economic viability and supporting grid reliability.

5.4 Concluding Remarks

This thesis has provided a thorough investigation into the emerging field of green hydrogen production in the U.S., focusing on the economic implications of different policy and business approaches. By examining the nuances of production costs, REC matching requirements, and the potential for strategic curtailment, we have uncovered valuable insights that can guide both policymakers and businesses in nurturing the green hydrogen sector. The recommendations put forth aim to strike a balance between fostering sustainable energy systems and ensuring economic feasibility.

As we look towards the future, it is clear that green hydrogen holds promise as part of a diversified energy portfolio, contributing to the broader goals of energy sustainability and decarbonization. While challenges remain, the pathways identified in this research offer practical steps forward, suggesting that with the right mix of policy support and industry initiative, green hydrogen can indeed play a significant role in the U.S. energy landscape. The journey ahead for green hydrogen is one of collaborative effort and continuous exploration, with the potential to make a meaningful impact on a sustainable energy future.

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Appendix A

Wind Resource Seasonality

A.1 Monthly Seasonality

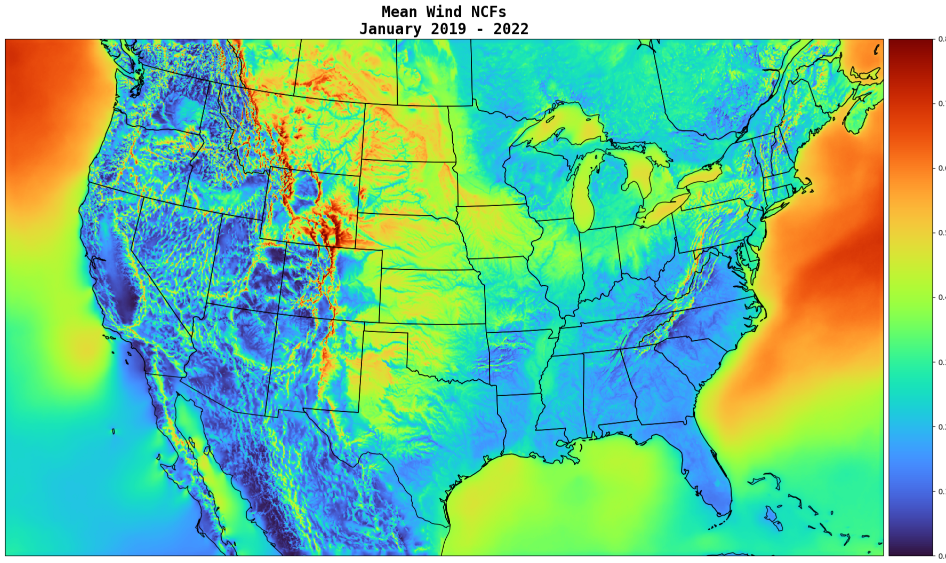

Figure A-1: Mean Wind NCF - January

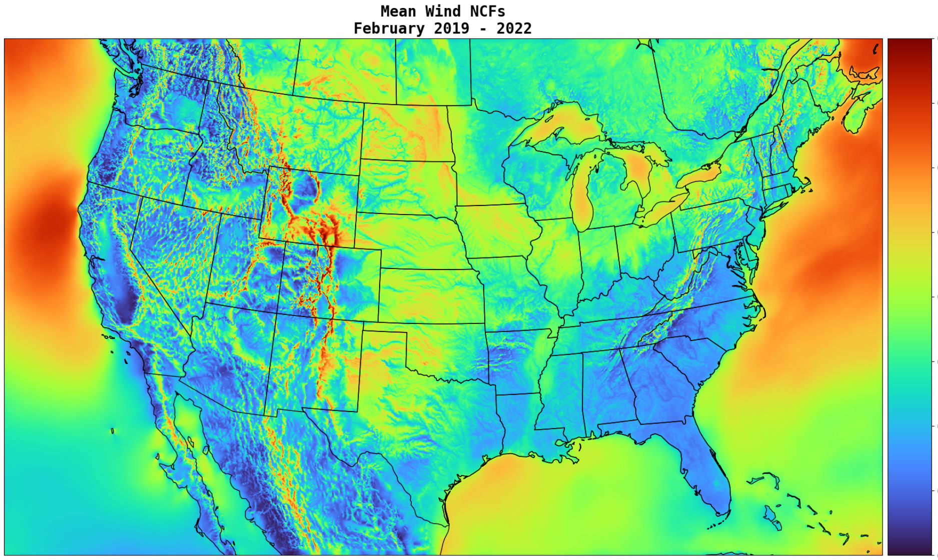

Figure A-2: Mean Wind NCF - Febuary

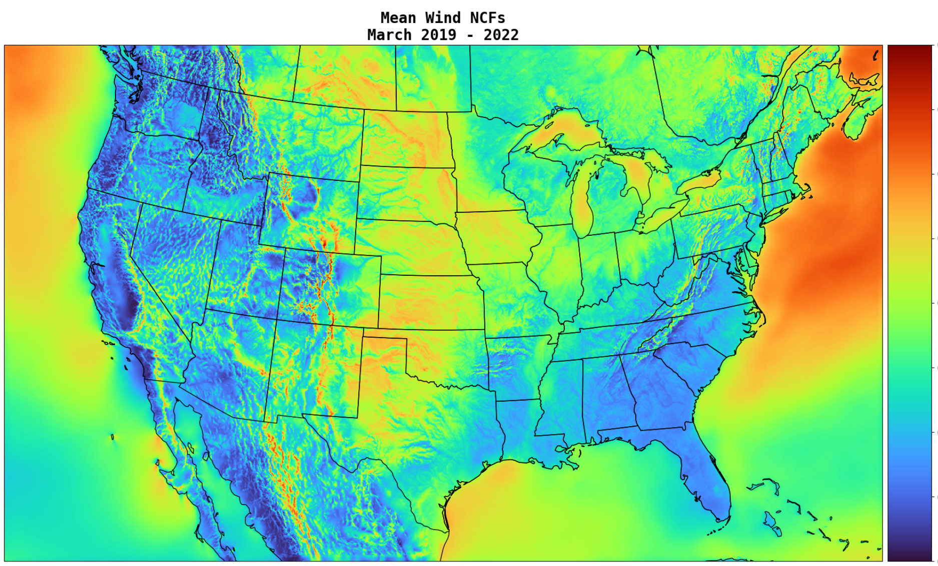

Figure A-3: Mean Wind NCF - March

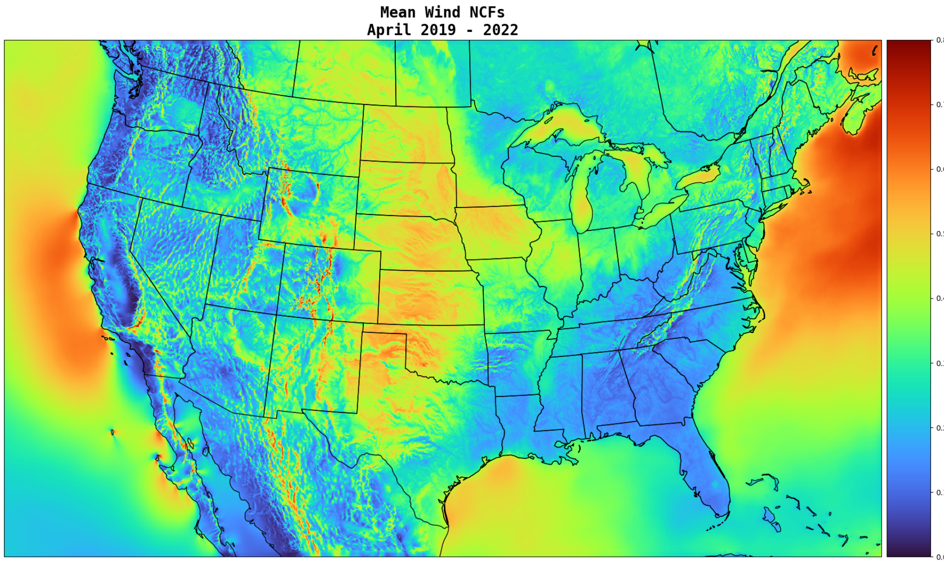

Figure A-4: Mean Wind NCF - April

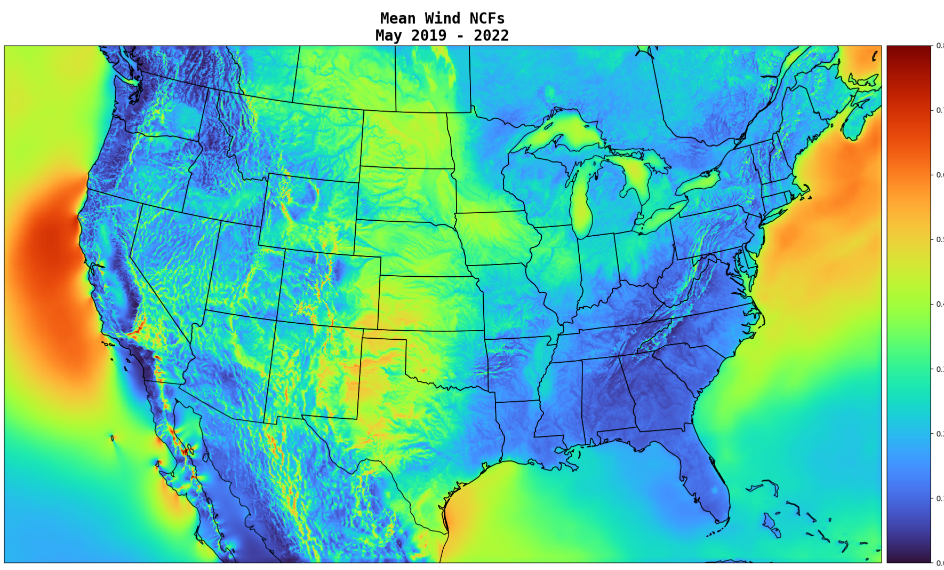

Figure A-5: Mean Wind NCF - May

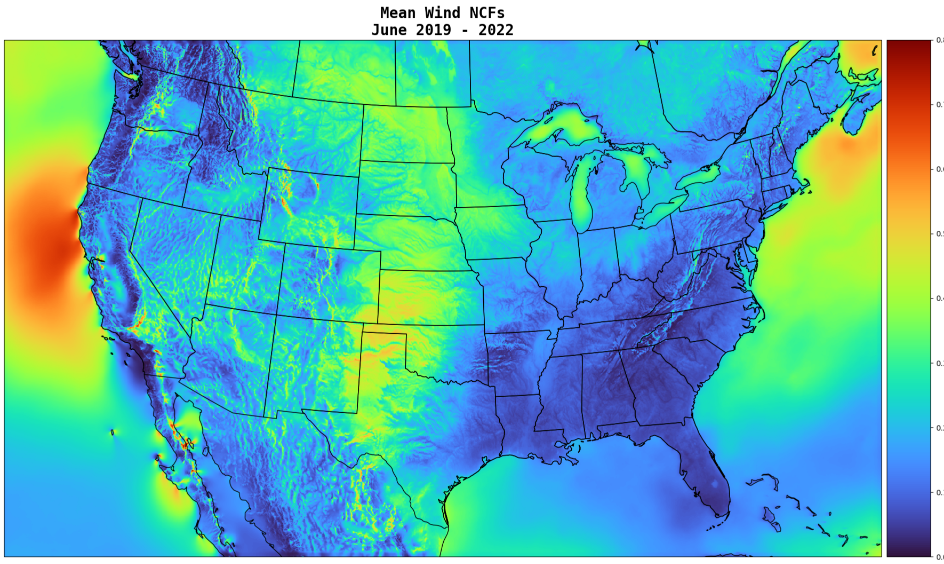

Figure A-6: Mean Wind NCF - June

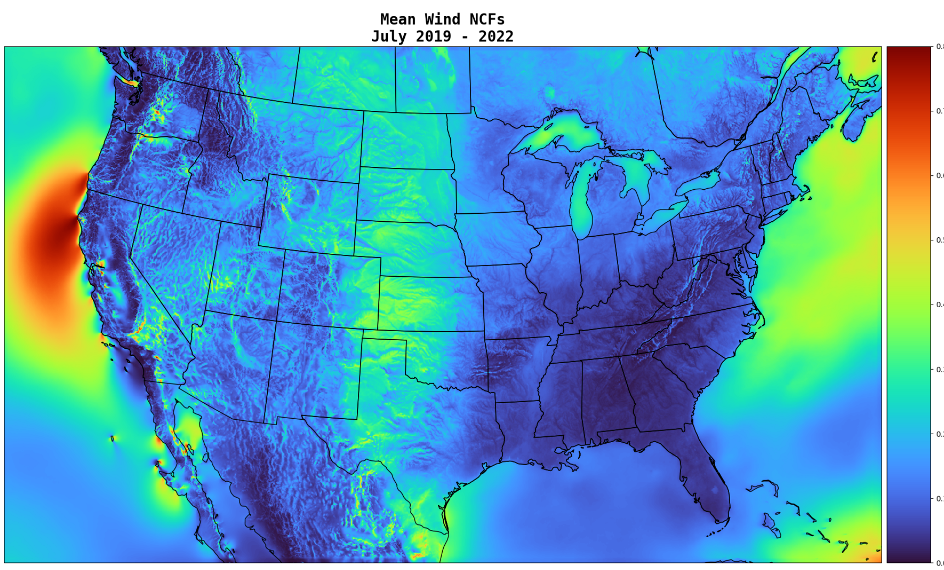

Figure A-7: Mean Wind NCF - July

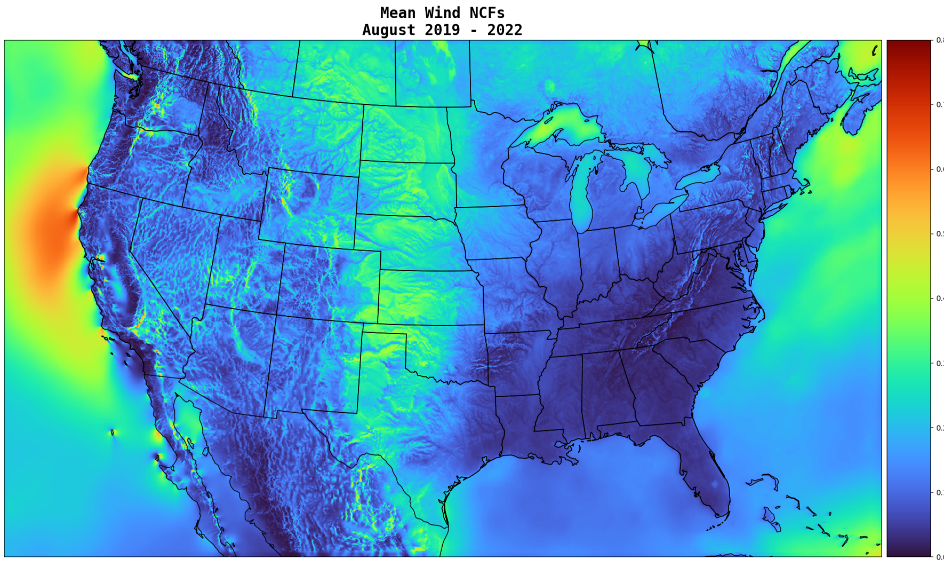

Figure A-8: Mean Wind NCF - August

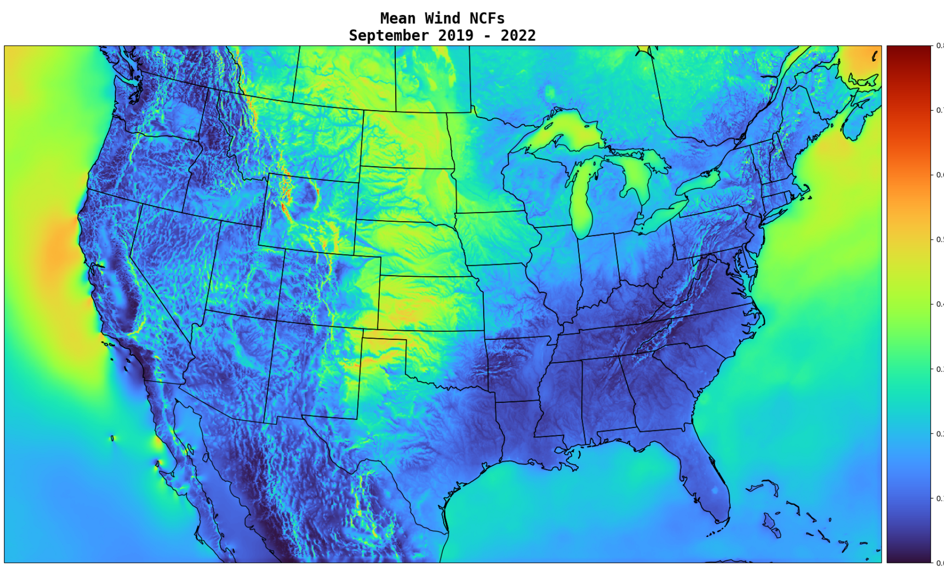

Figure A-9: Mean Wind NCF - September

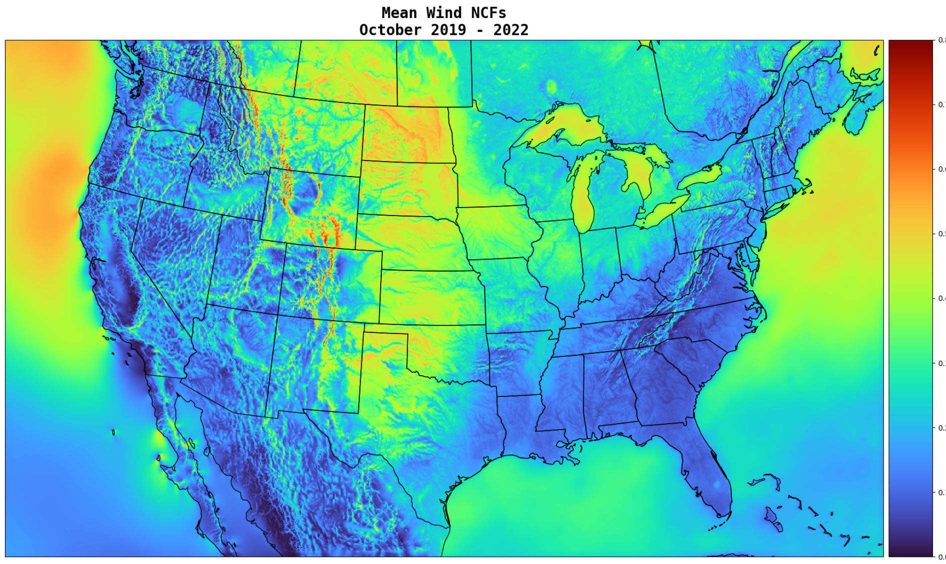

Figure A-10: Mean Wind NCF - October

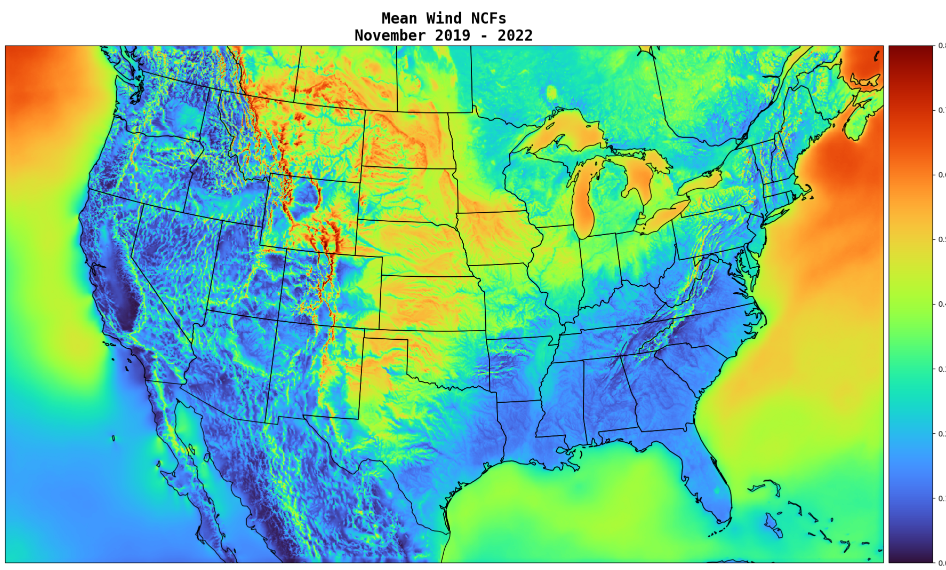

Figure A-11: Mean Wind NCF - November

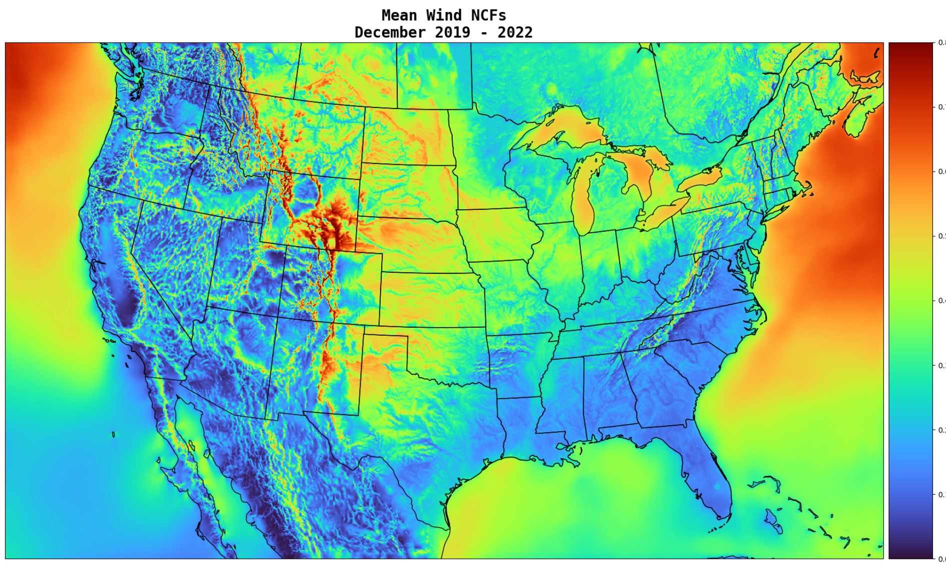

Figure A-12: Mean Wind NCF - December

A.2 Hourly Seasonality

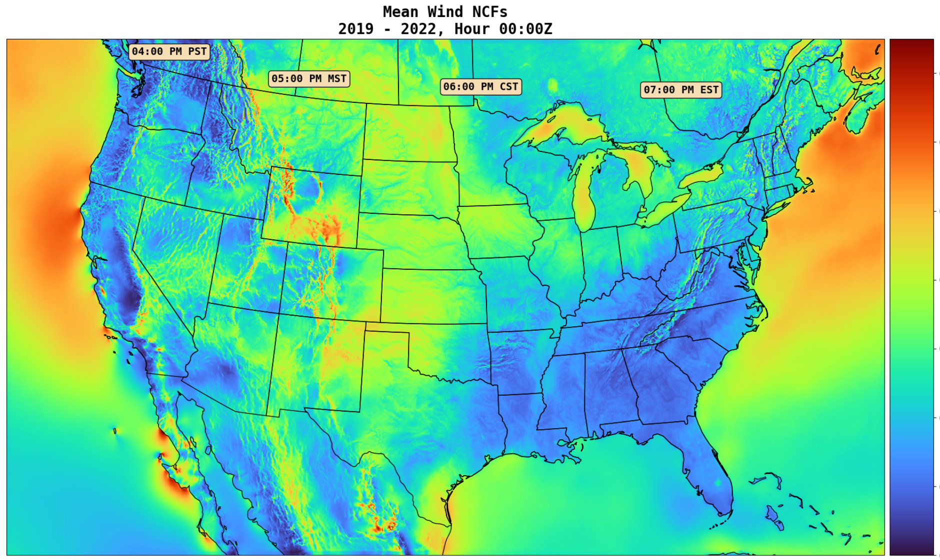

Figure A-13: Mean Wind NCF - Hour 00Z

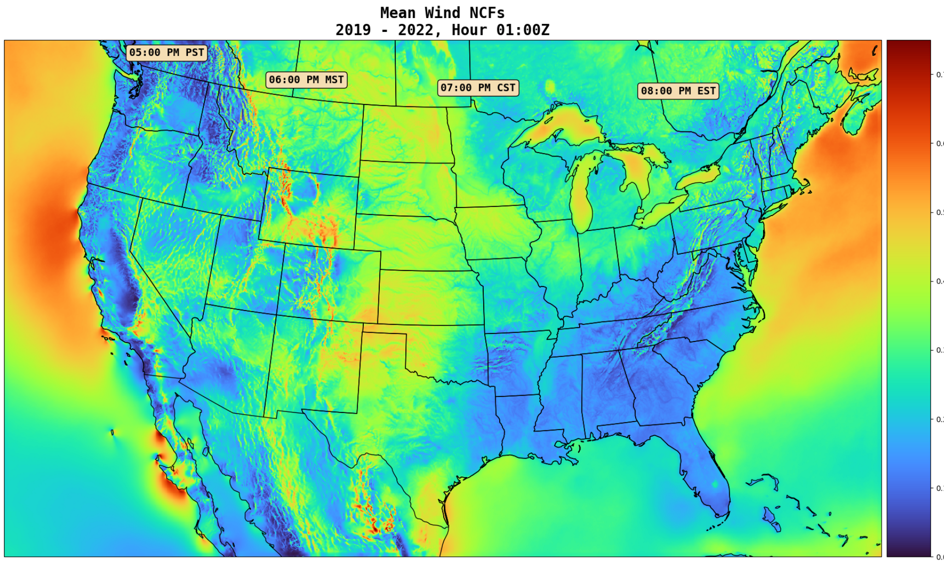

Figure A-14: Mean Wind NCF - Hour 01Z

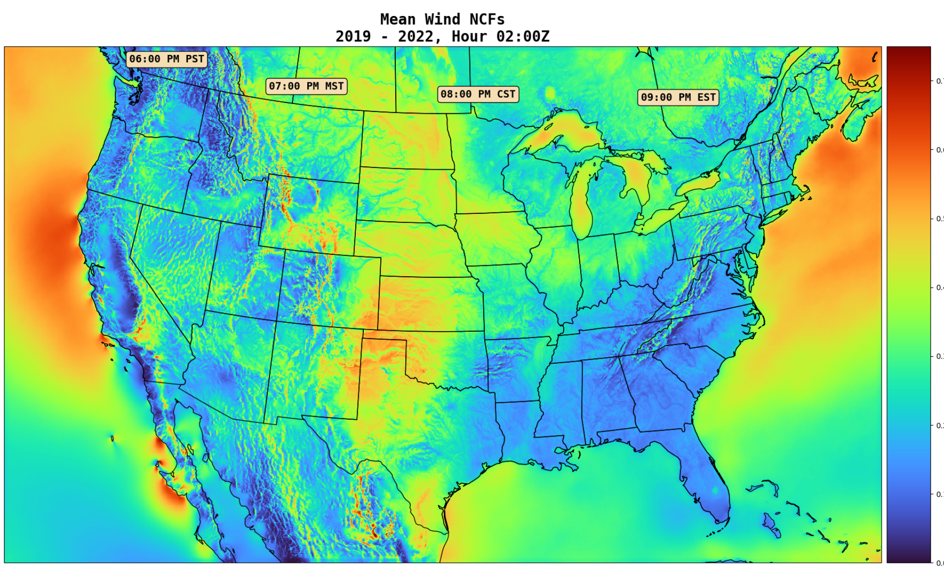

Figure A-15: Mean Wind NCF - Hour 02Z

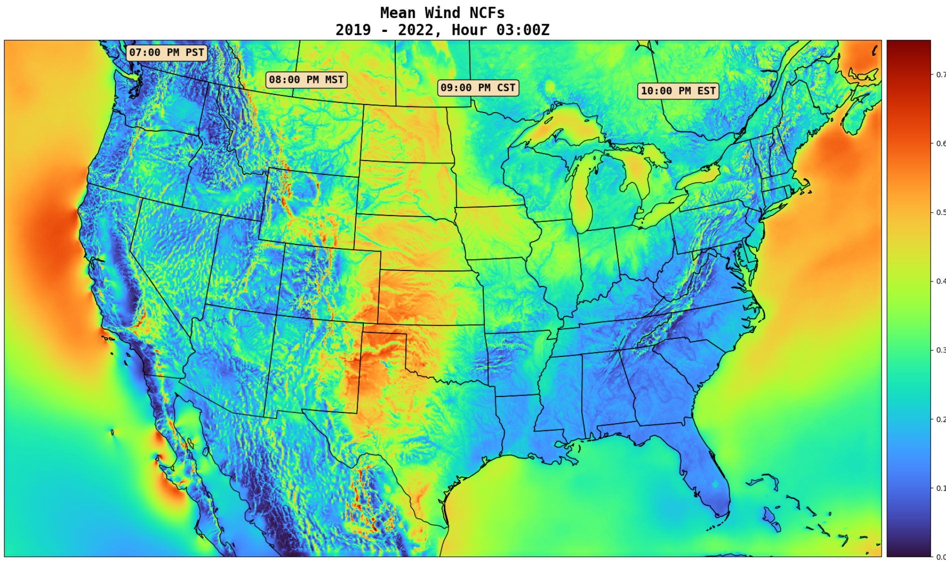

Figure A-16: Mean Wind NCF - Hour 03Z

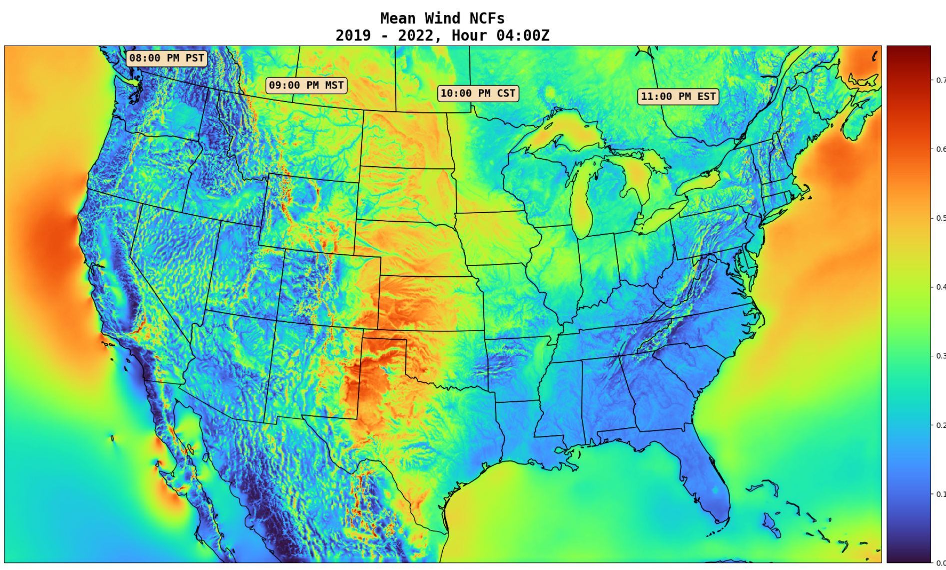

Figure A-17: Mean Wind NCF - Hour 04Z

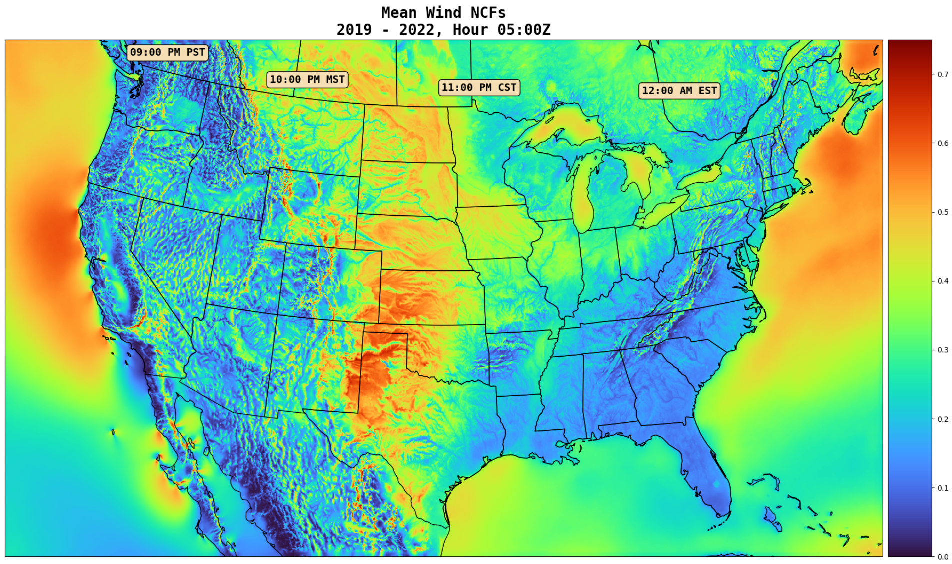

Figure A-18: Mean Wind NCF - Hour 05Z

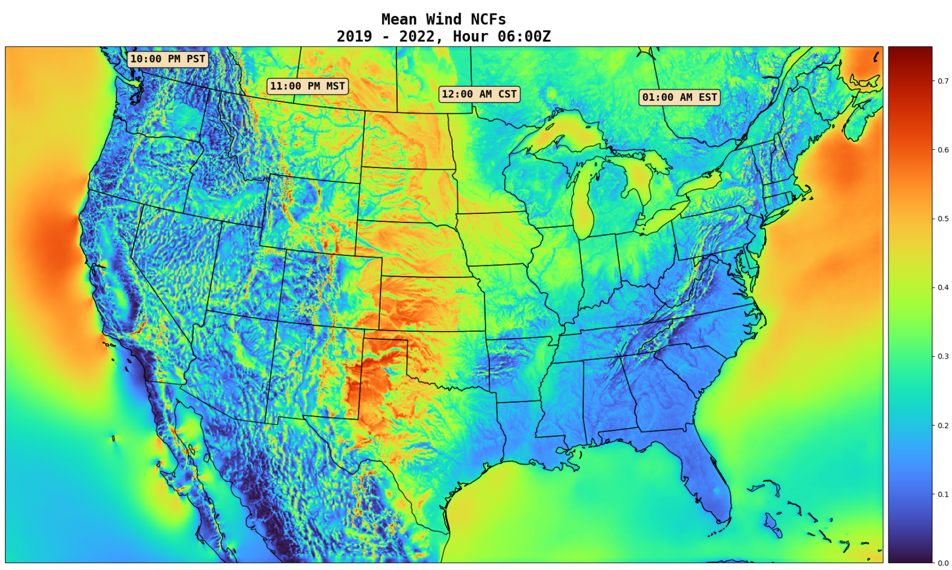

Figure A-19: Mean Wind NCF - Hour 06Z

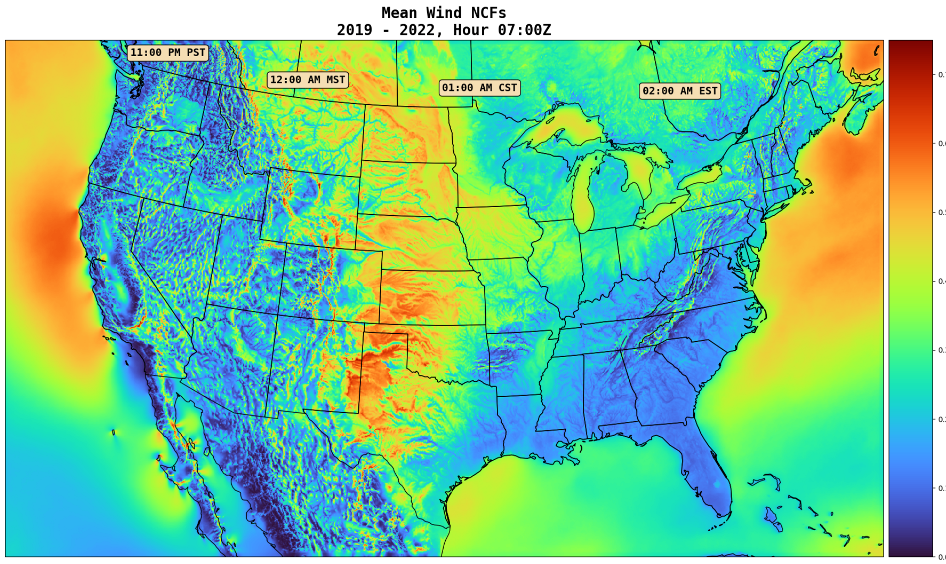

Figure A-20: Mean Wind NCF - Hour 07Z

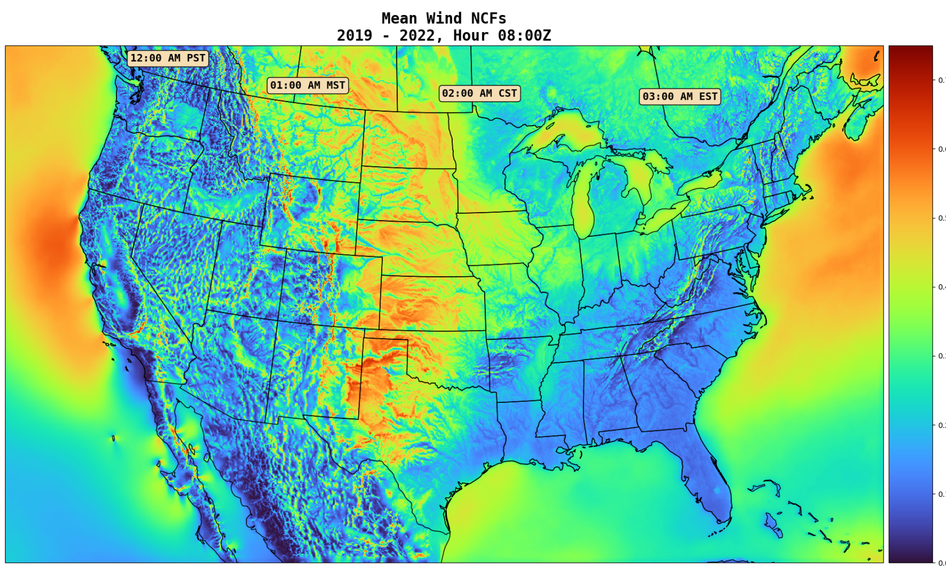

Figure A-21: Mean Wind NCF - Hour 08Z

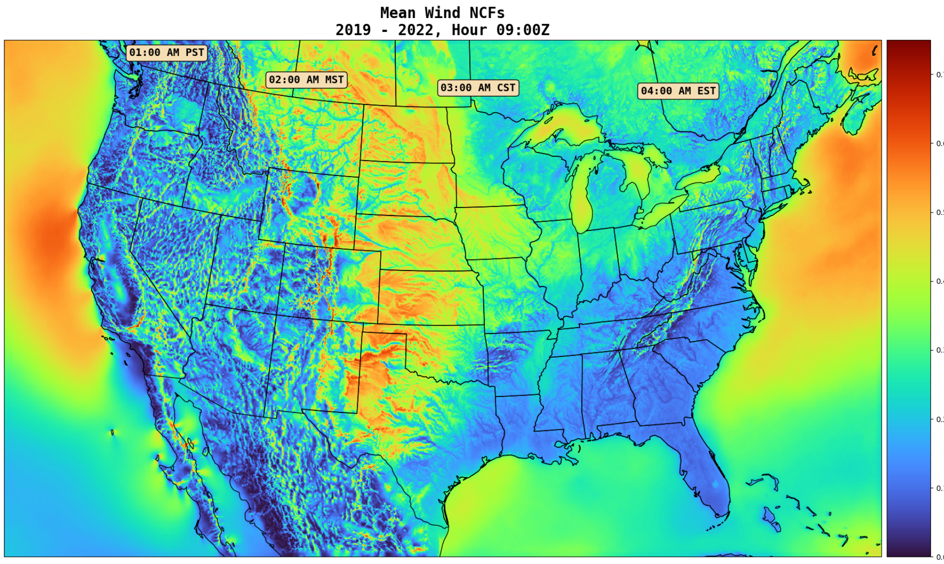

Figure A-22: Mean Wind NCF - Hour 09Z

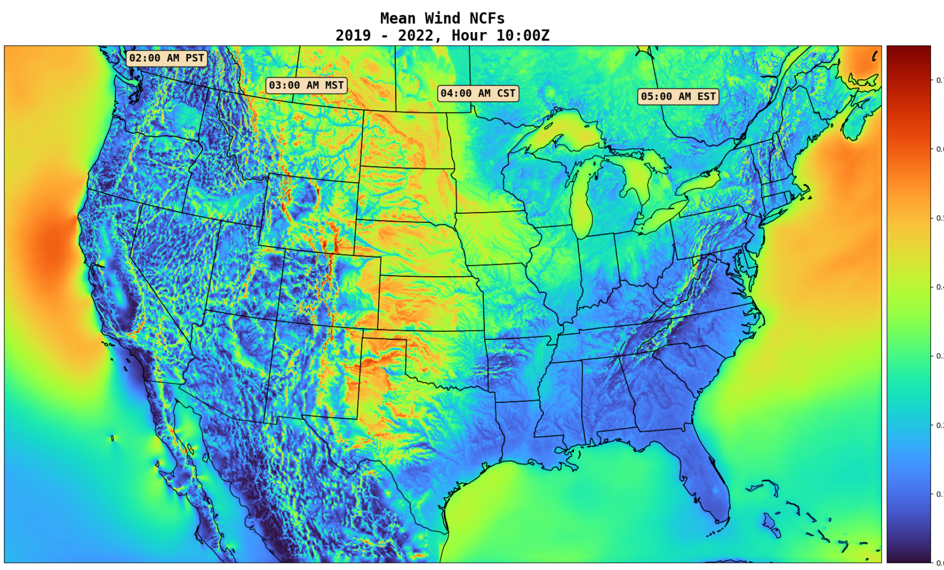

Figure A-23: Mean Wind NCF - Hour 10Z

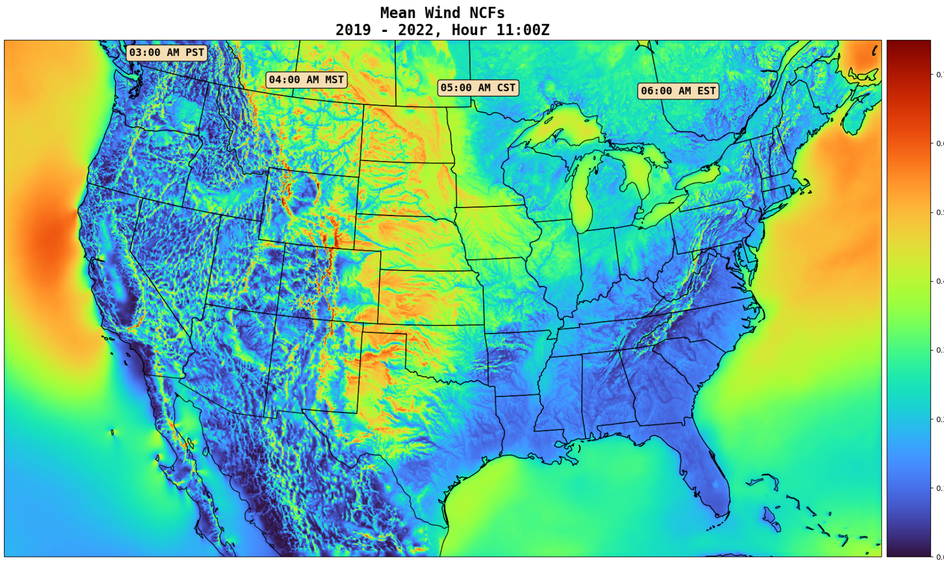

Figure A-24: Mean Wind NCF - Hour 11Z

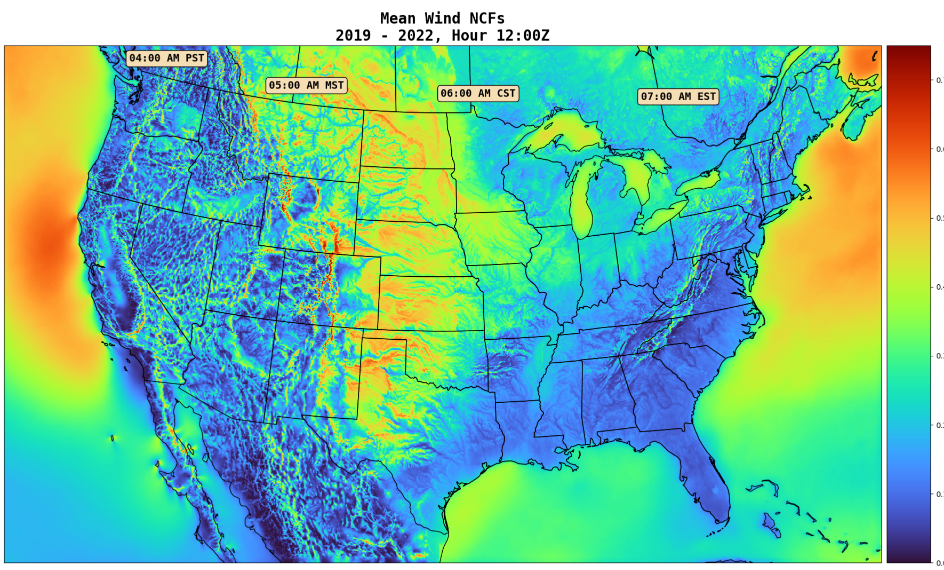

Figure A-25: Mean Wind NCF - Hour 12Z

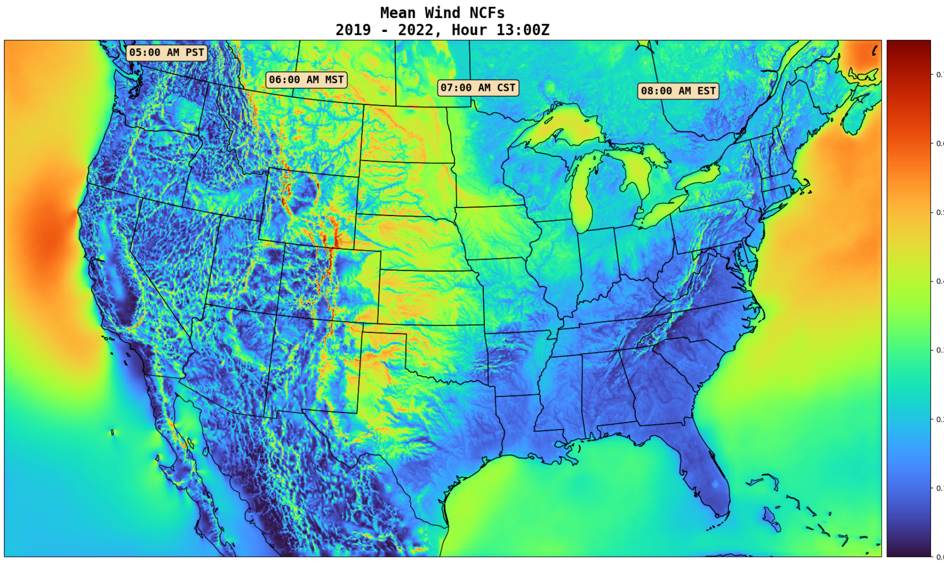

Figure A-26: Mean Wind NCF - Hour 13Z

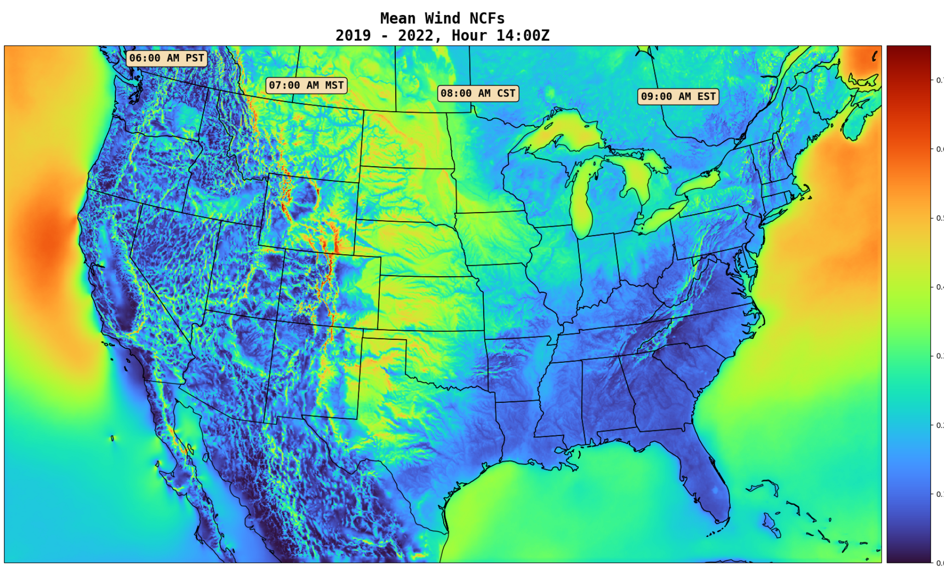

Figure A-27: Mean Wind NCF - Hour 14Z

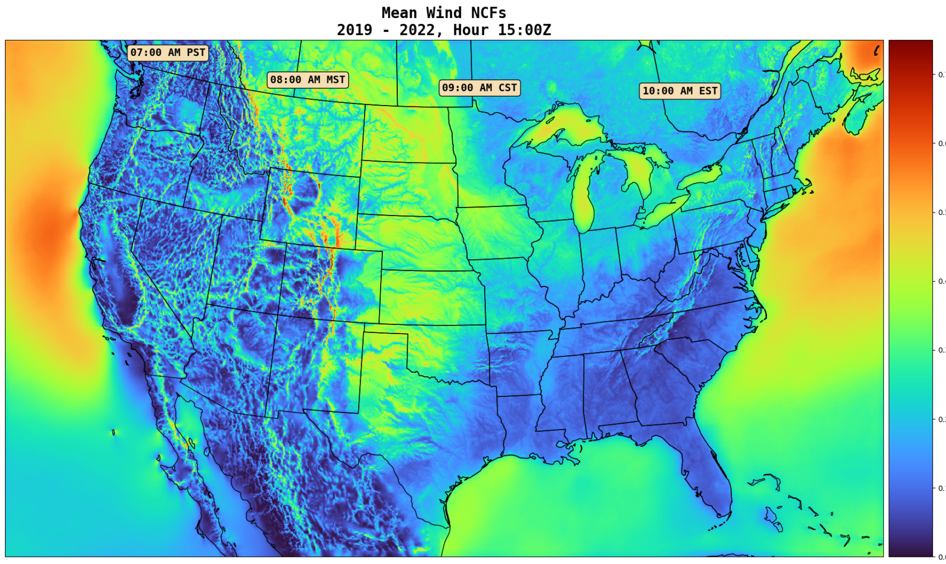

Figure A-28: Mean Wind NCF - Hour 15Z

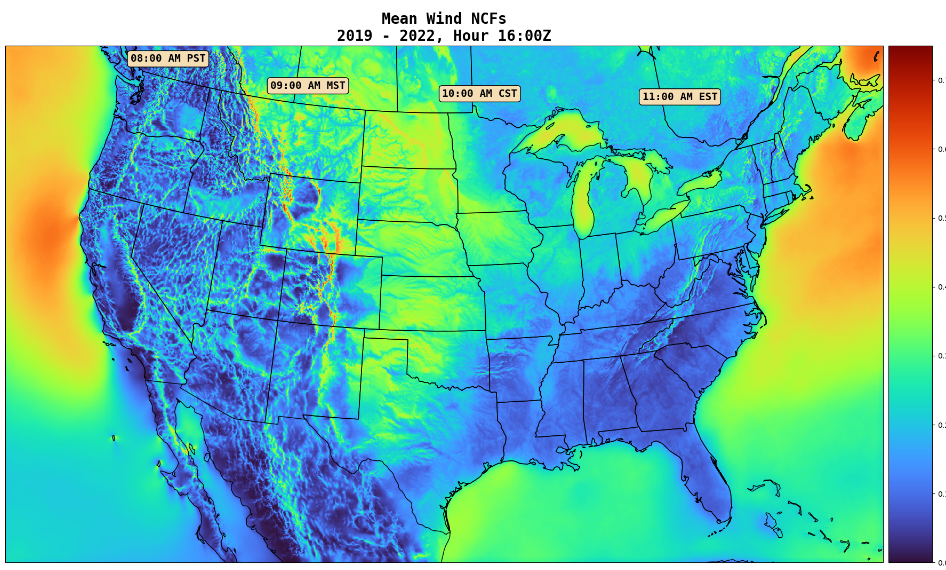

Figure A-29: Mean Wind NCF - Hour 16Z

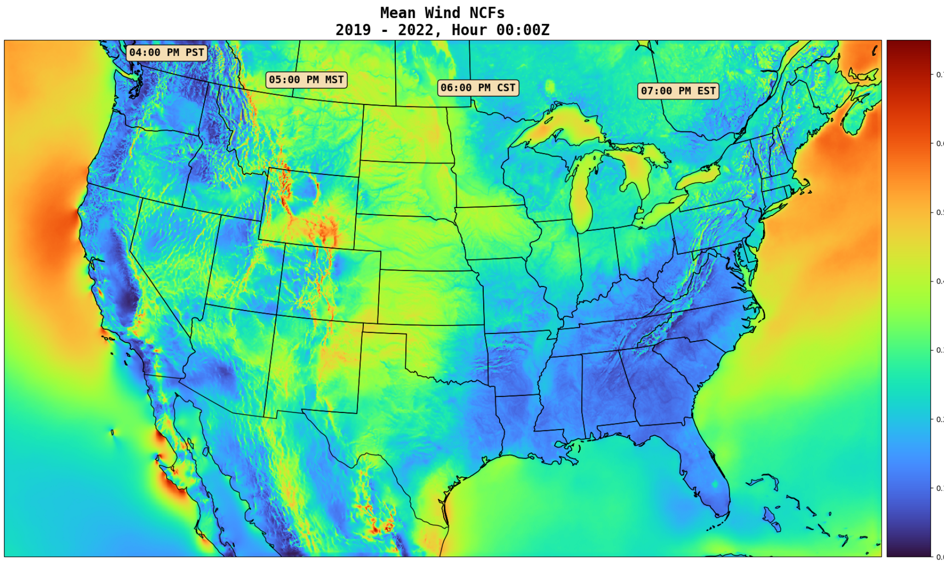

Figure A-30: Mean Wind NCF - Hour 17Z

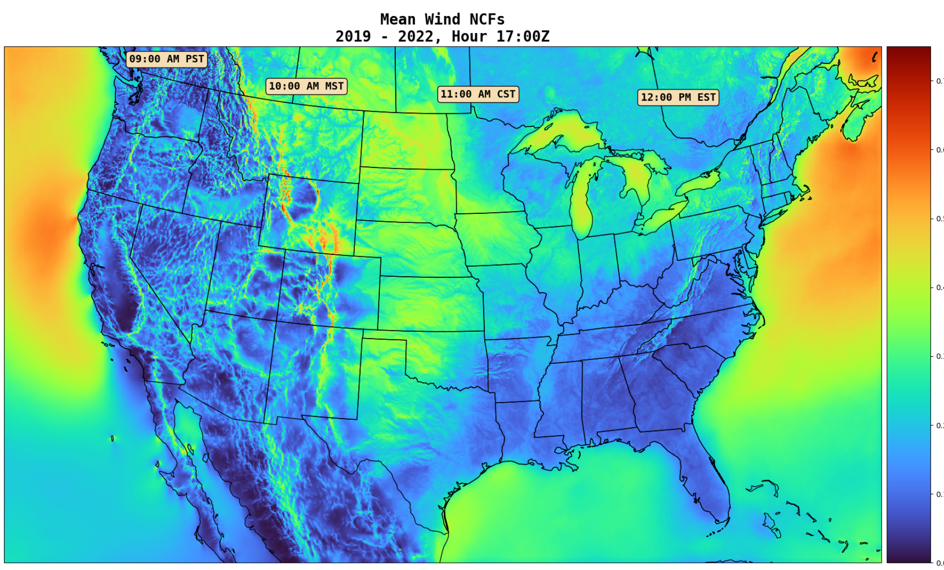

Figure A-31: Mean Wind NCF - Hour 17Z

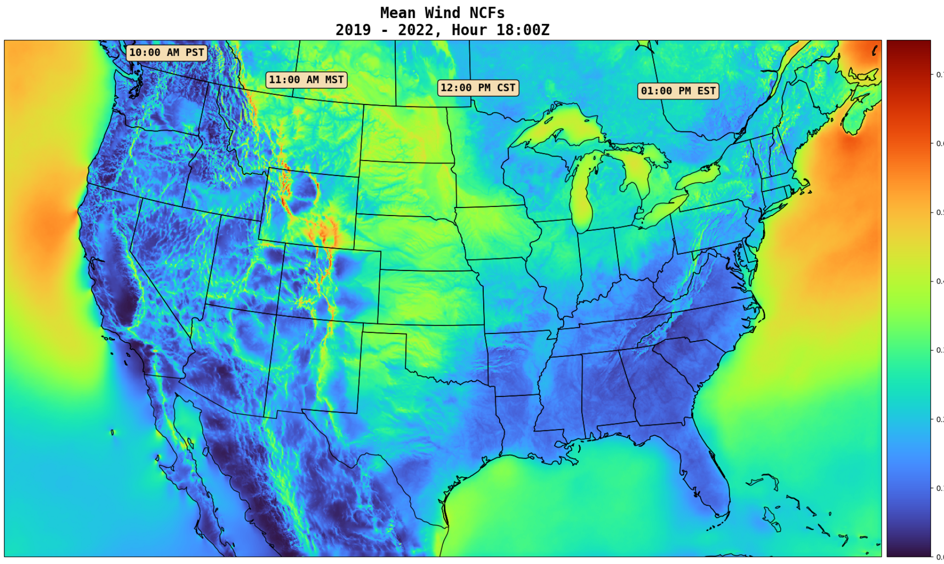

Figure A-32: Mean Wind NCF - Hour 18Z

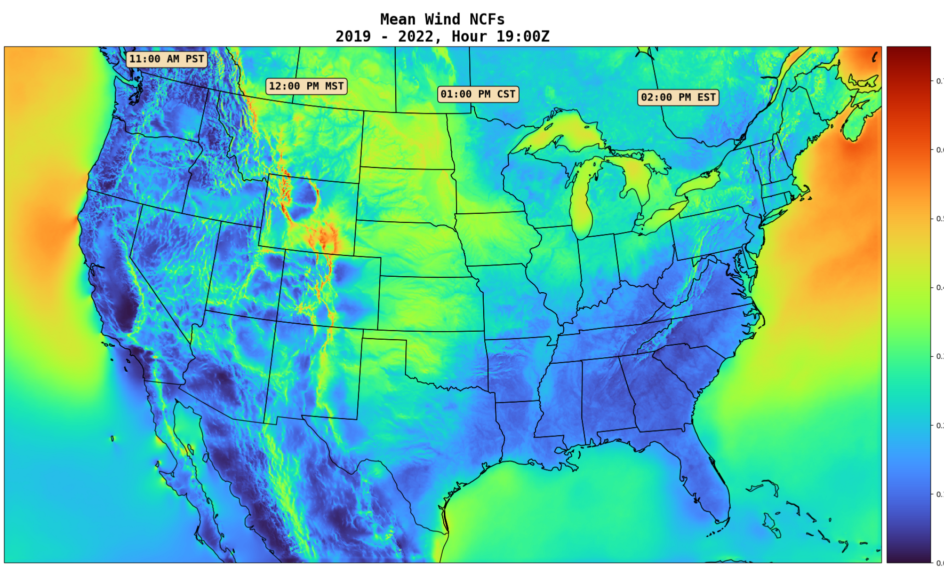

Figure A-33: Mean Wind NCF - Hour 19Z

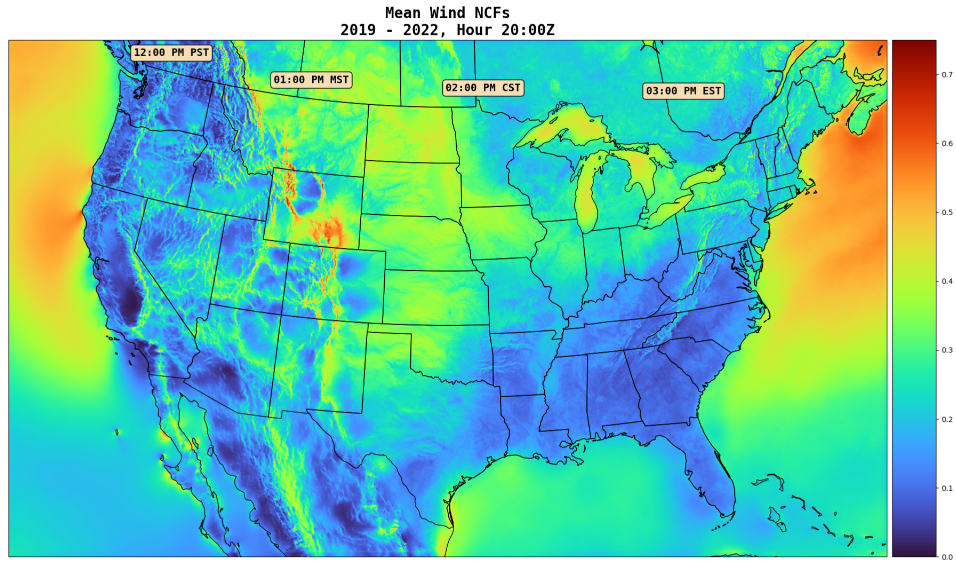

Figure A-34: Mean Wind NCF - Hour 20Z

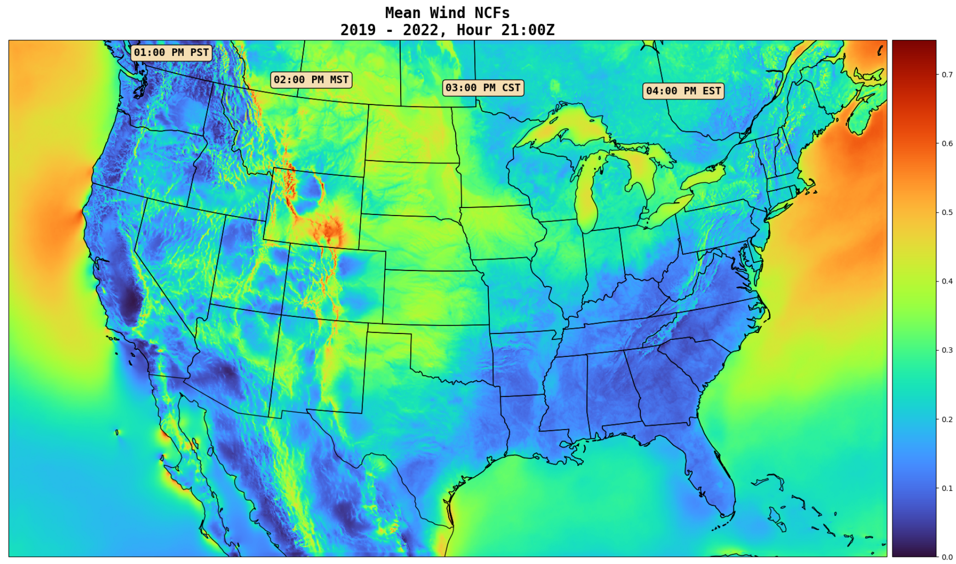

Figure A-35: Mean Wind NCF - Hour 21Z

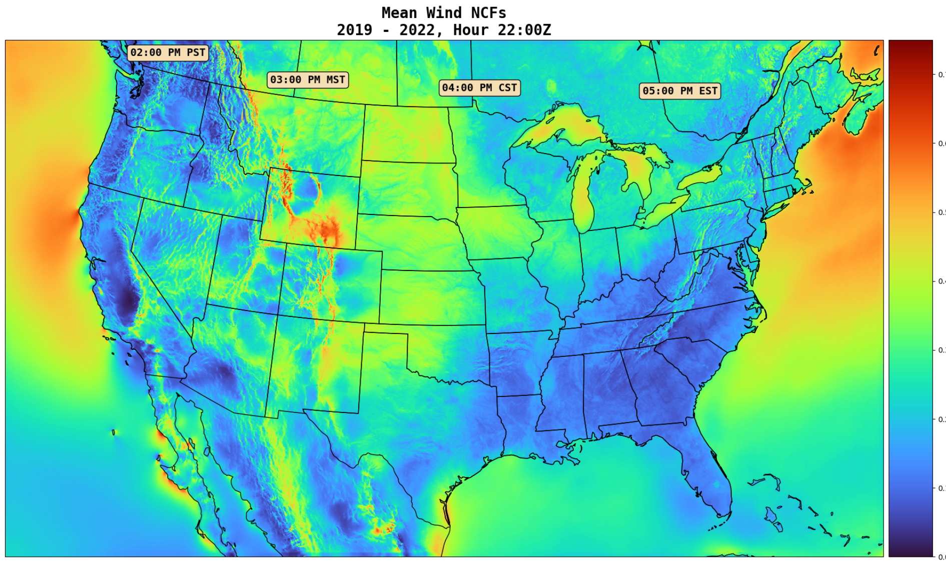

Figure A-36: Mean Wind NCF - Hour 22Z

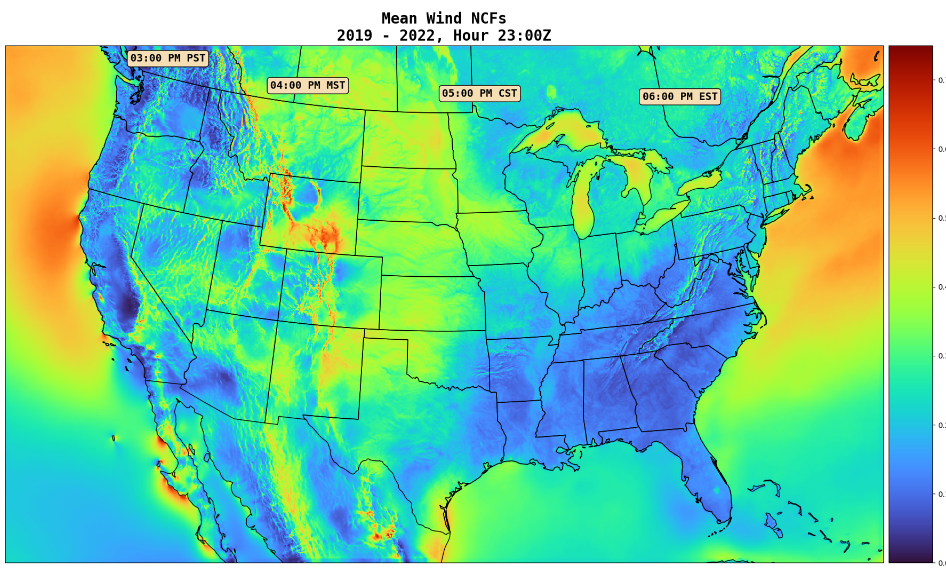

Figure A-37: Mean Wind NCF - Hour 23Z

Appendix B

Solar Resource Seasonality

B.1 Monthly Seasonality

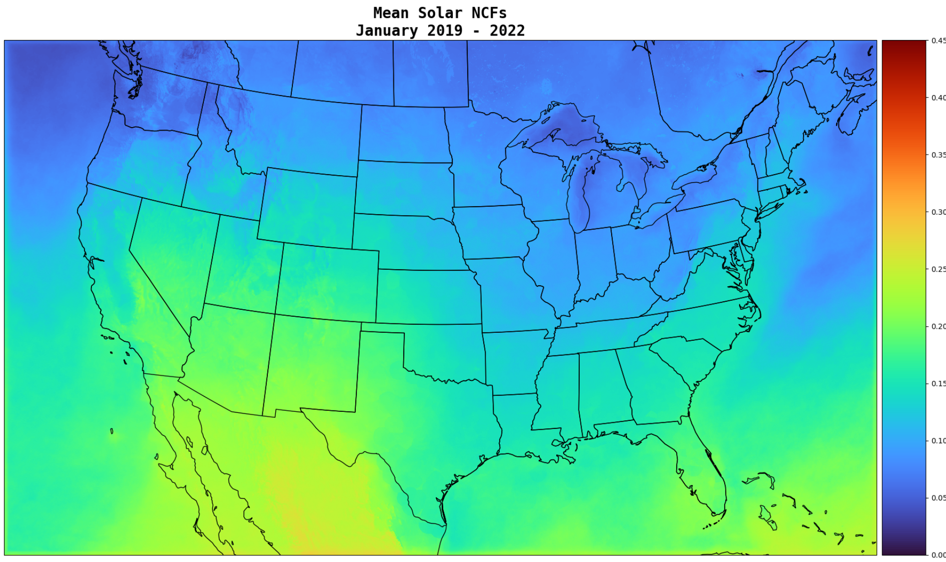

Figure B-1: Mean Solar NCF - January

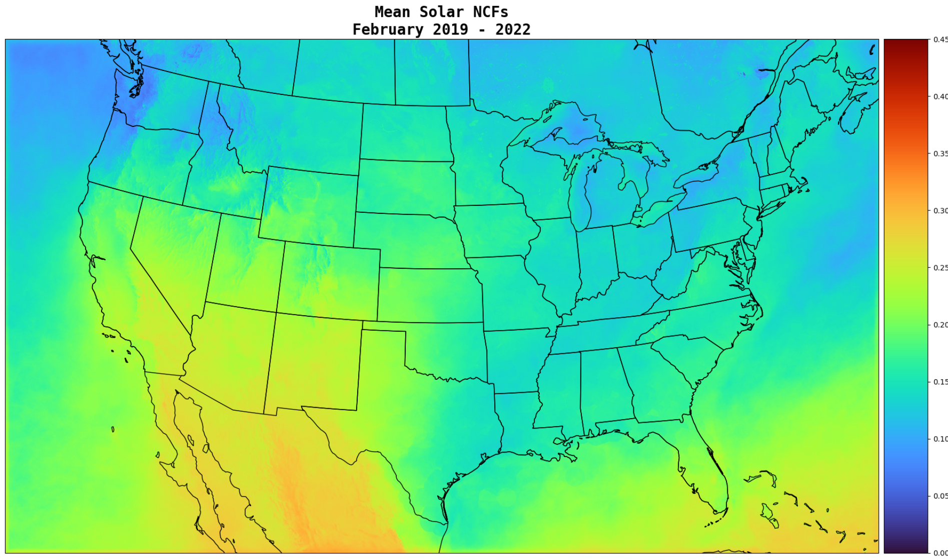

Figure B-2: Mean Solar NCF - Febuary

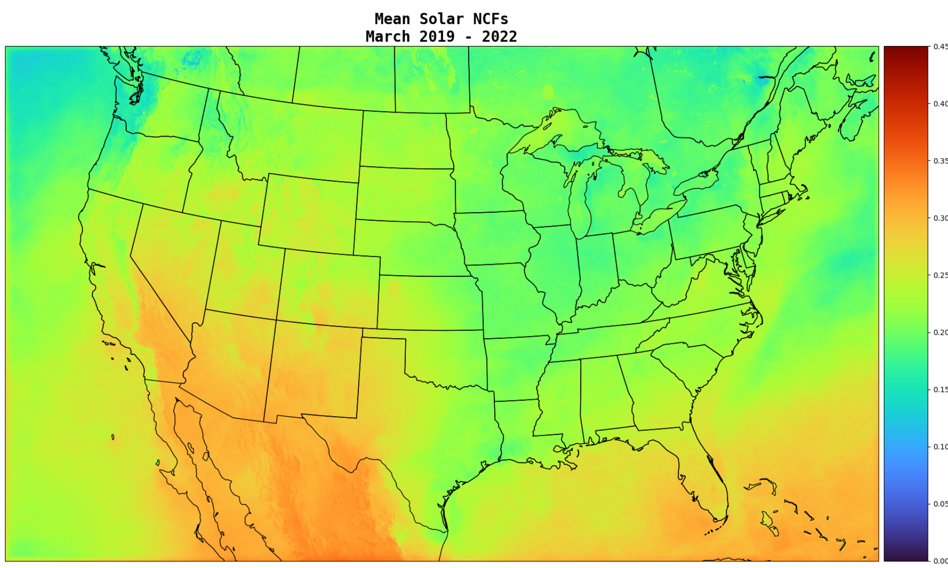

Figure B-3: Mean Solar NCF - March

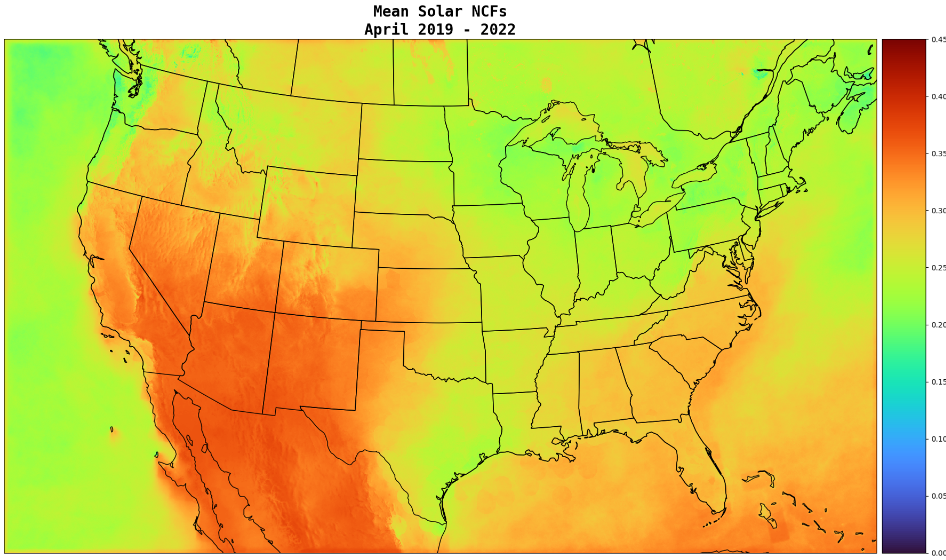

Figure B-4: Mean Solar NCF - April

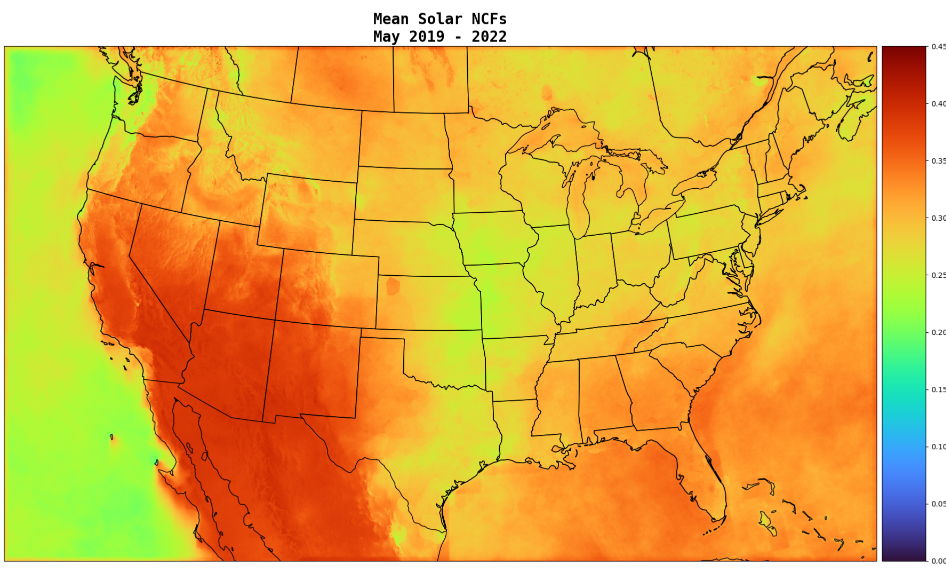

Figure B-5: Mean Solar NCF - May

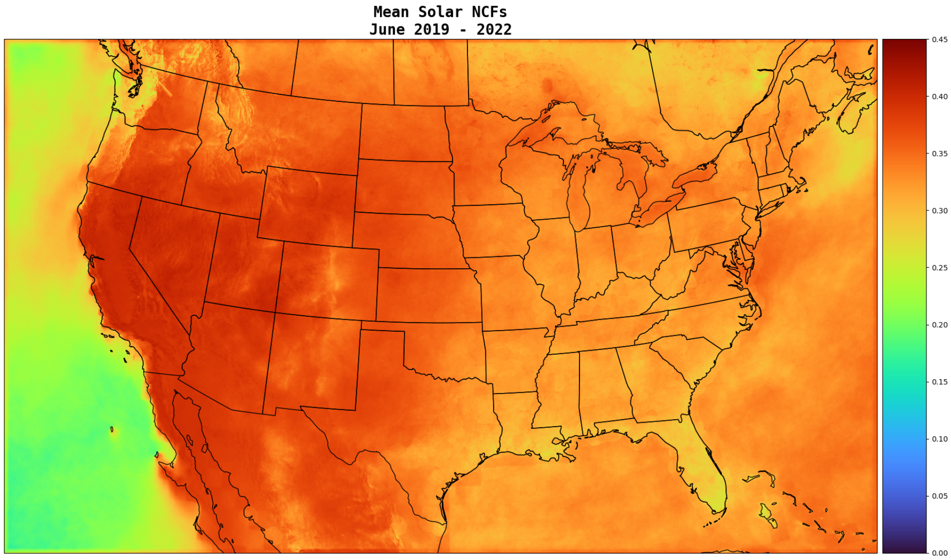

Figure B-6: Mean Solar NCF - June

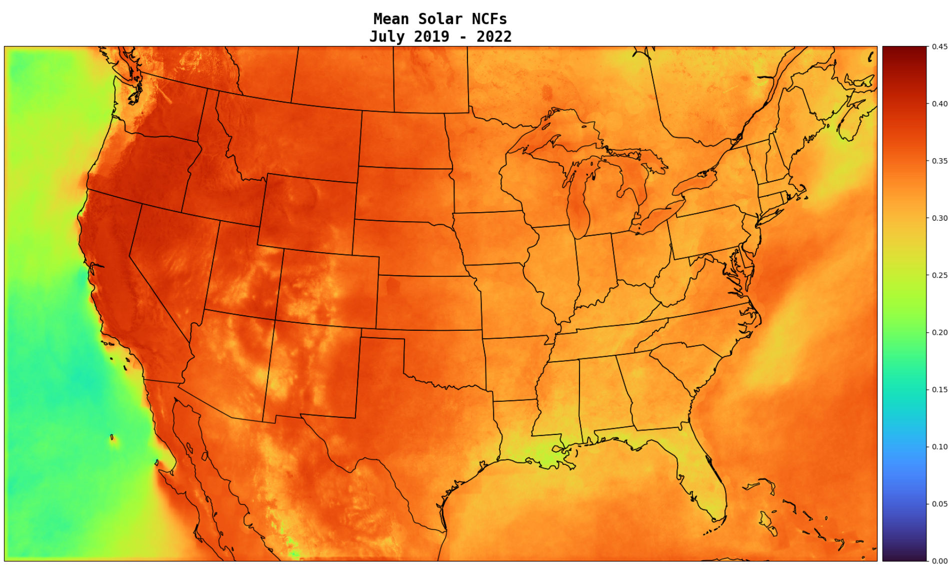

Figure B-7: Mean Solar NCF - July

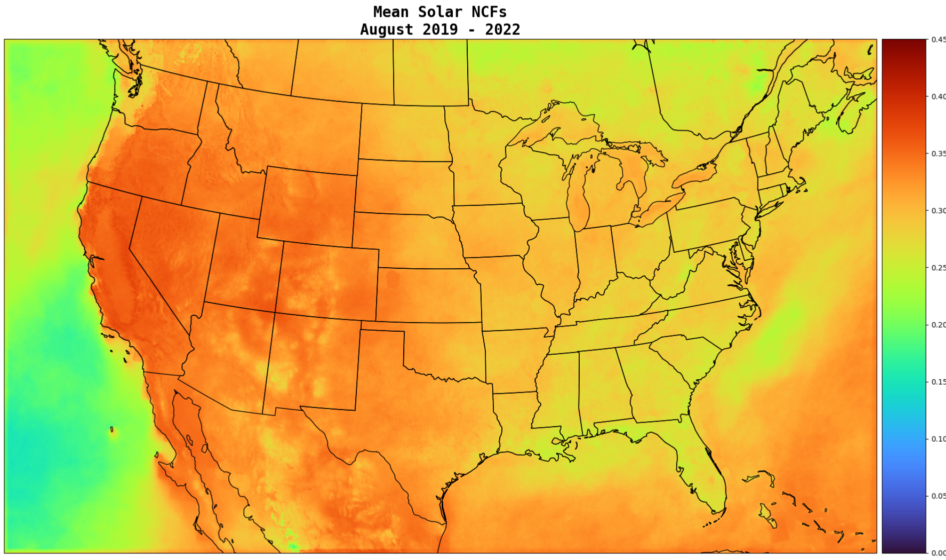

Figure B-8: Mean Solar NCF - August

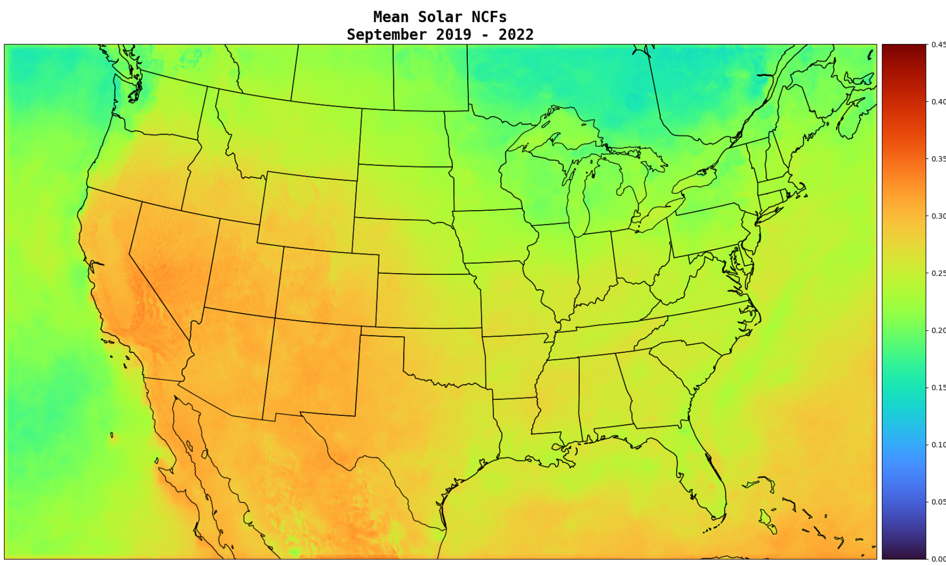

Figure B-9: Mean Solar NCF - September

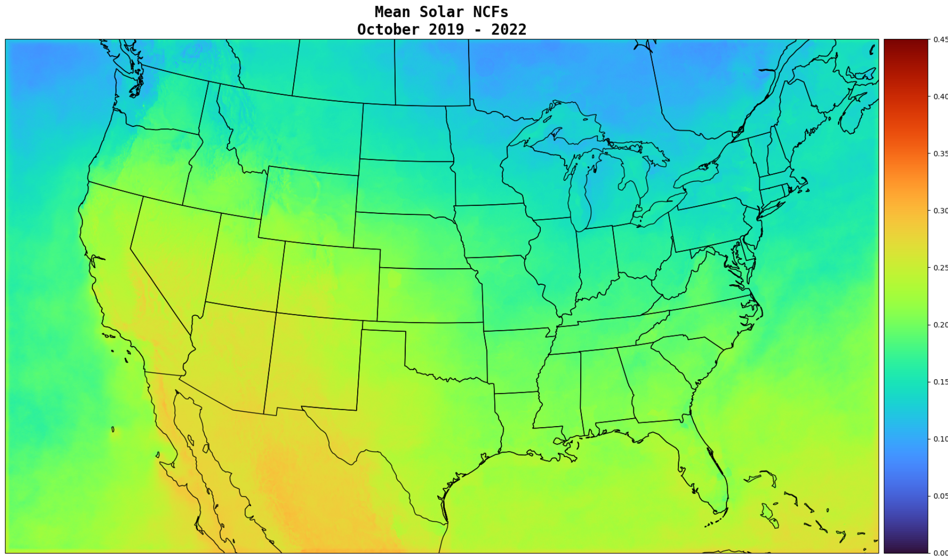

Figure B-10: Mean Solar NCF - October

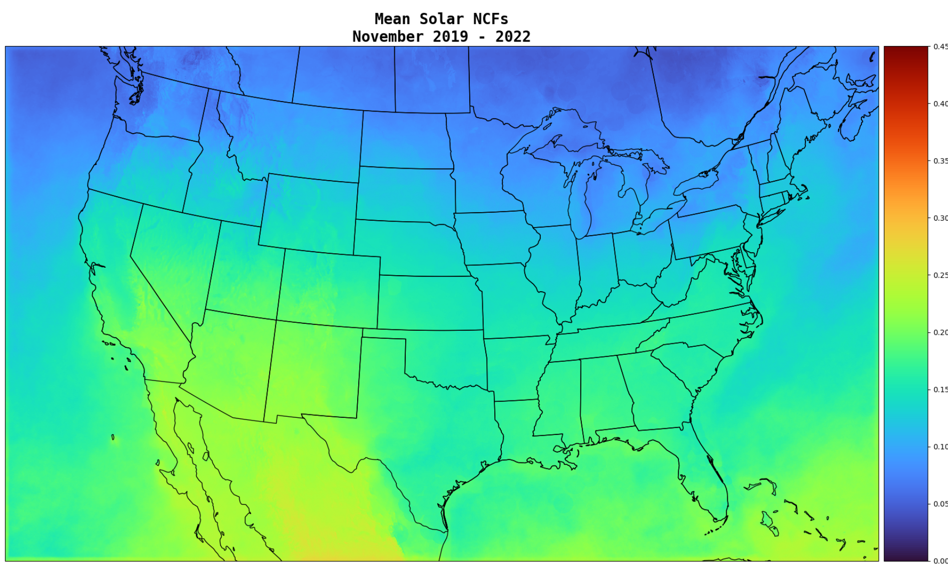

Figure B-11: Mean Solar NCF - November

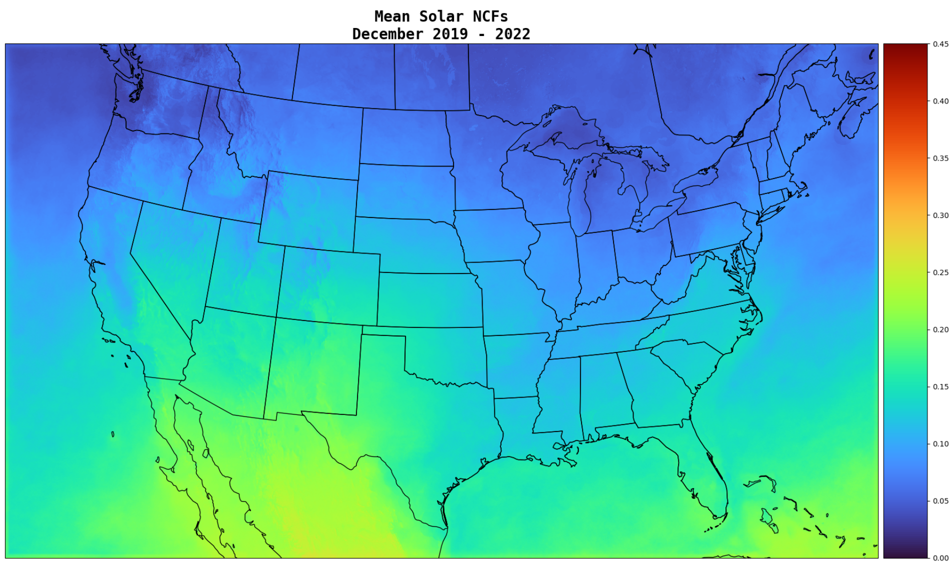

Figure B-12: Mean Solar NCF - December

B.2 Hourly Seasonality

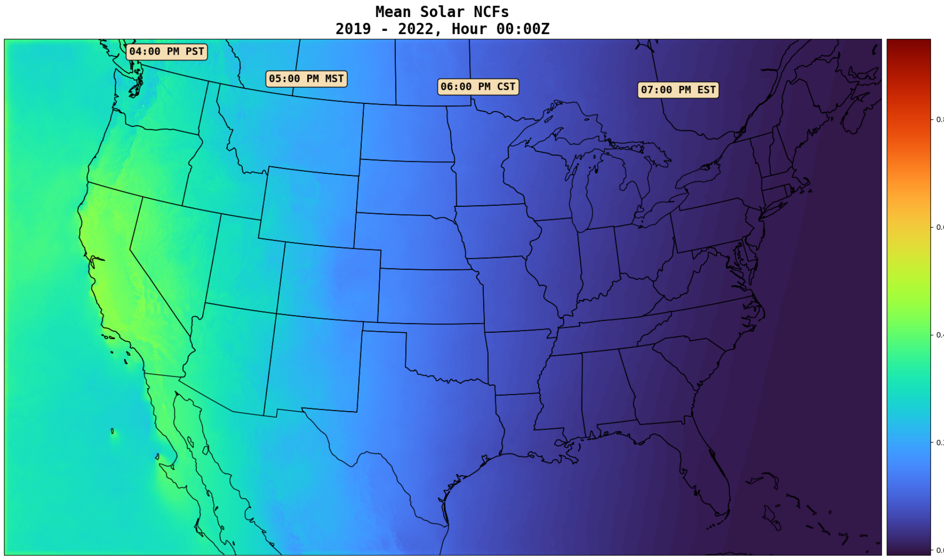

Figure B-13: Mean Solar NCF - Hour 00Z

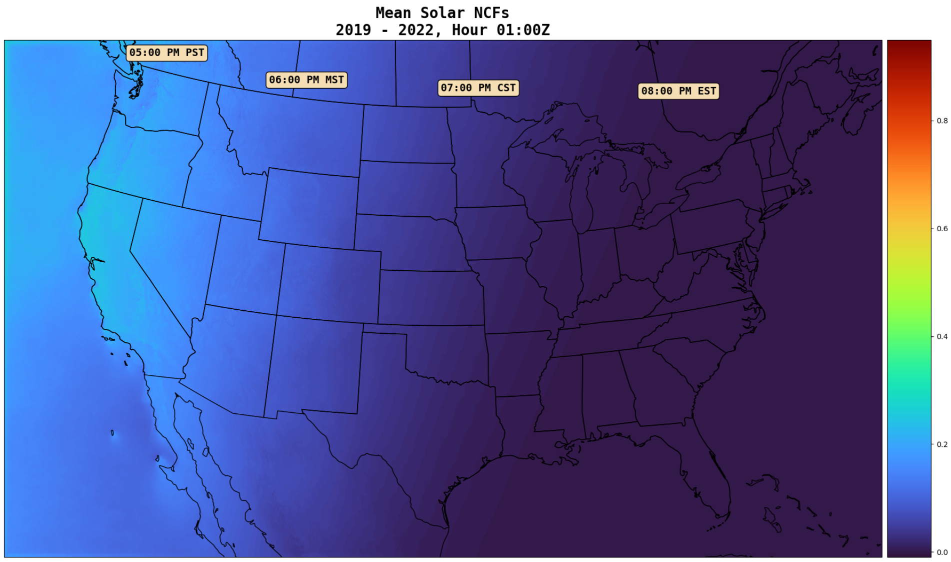

Figure B-14: Mean Solar NCF - Hour 01Z

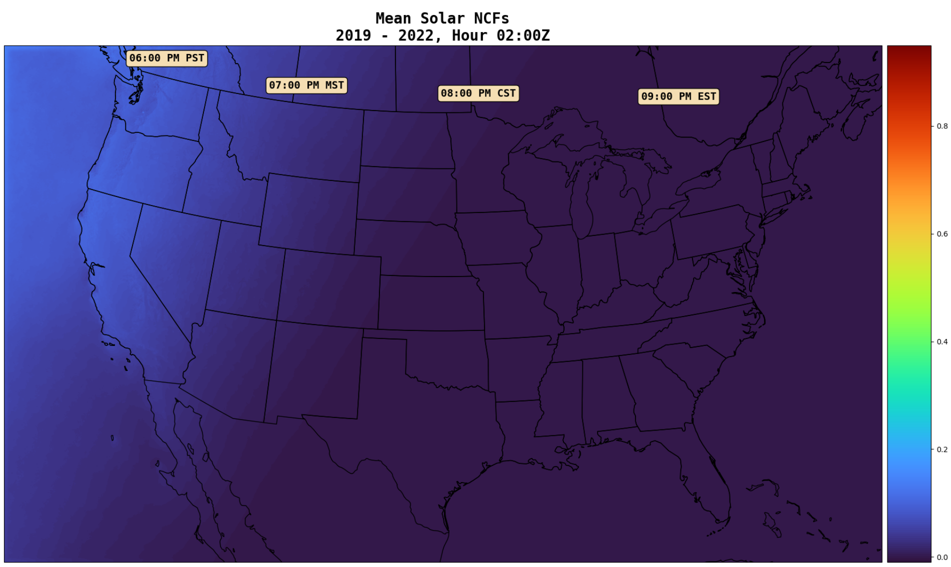

Figure B-15: Mean Solar NCF - Hour 02Z

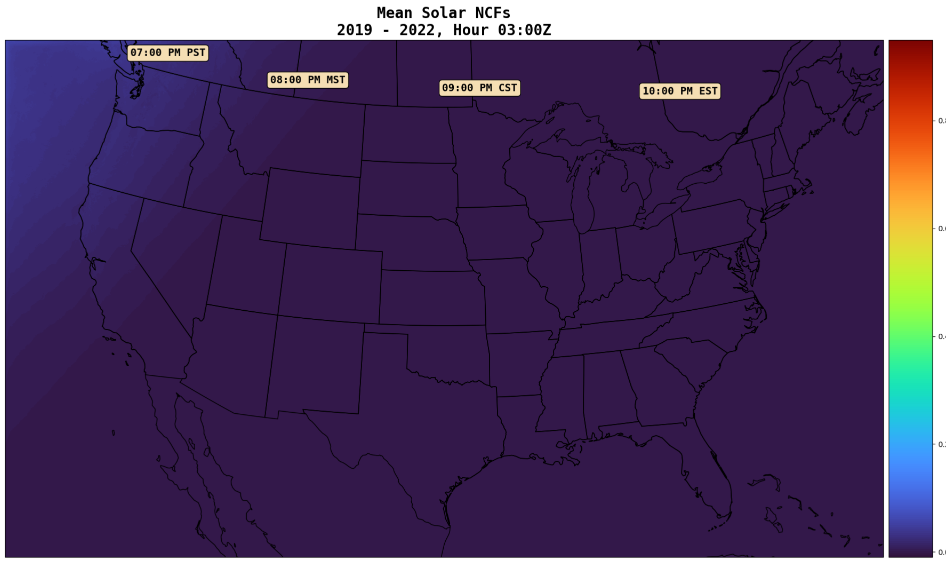

Figure B-16: Mean Solar NCF - Hour 03Z

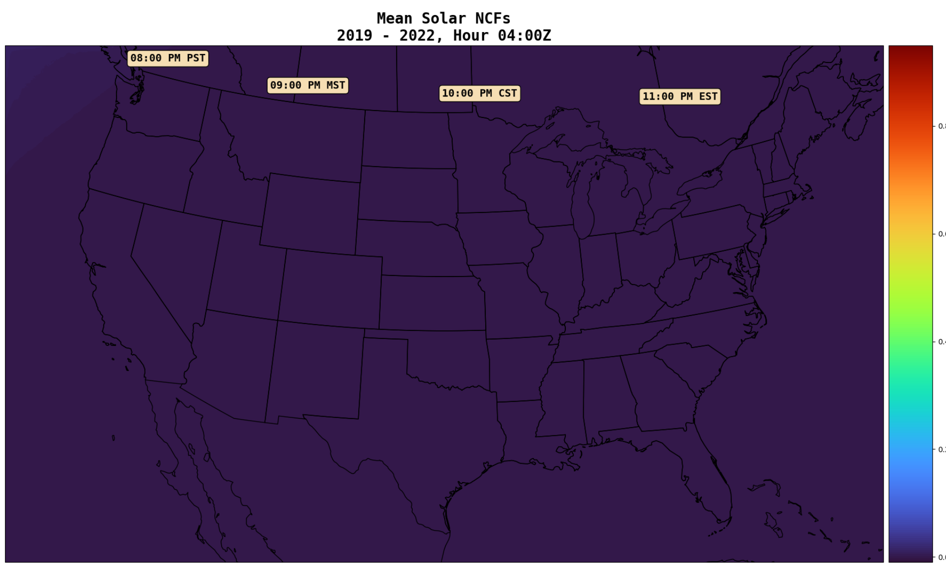

Figure B-17: Mean Solar NCF - Hour 04Z

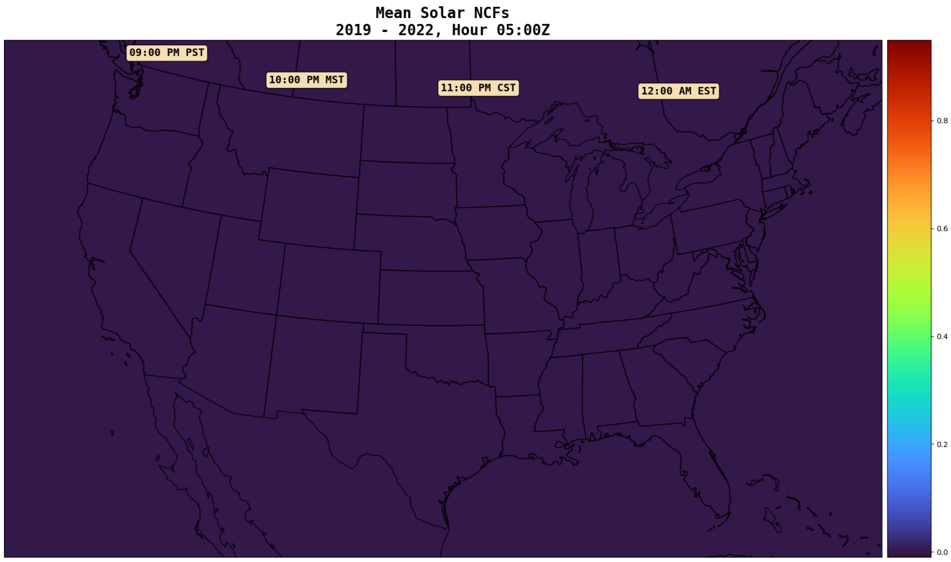

Figure B-18: Mean Solar NCF - Hour 05Z

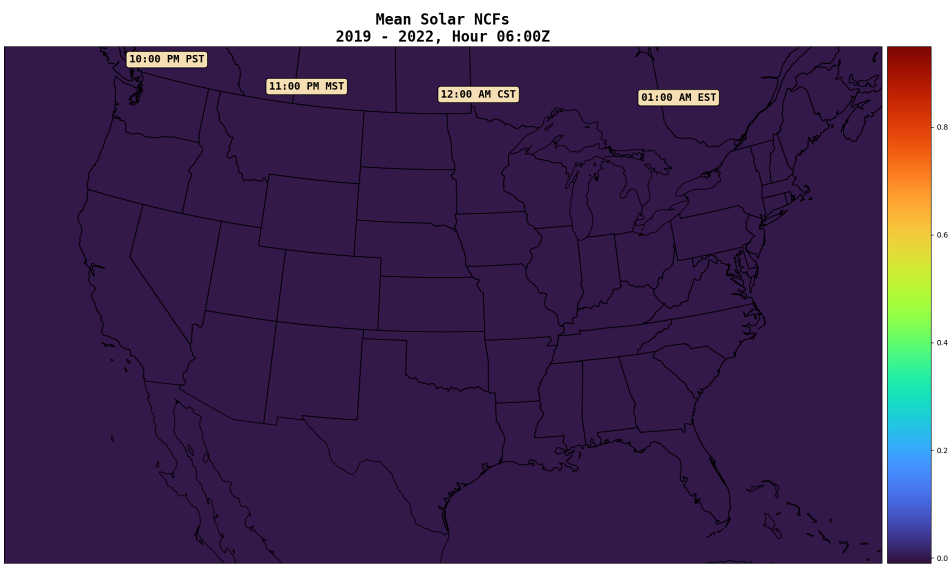

Figure B-19: Mean Solar NCF - Hour 06Z

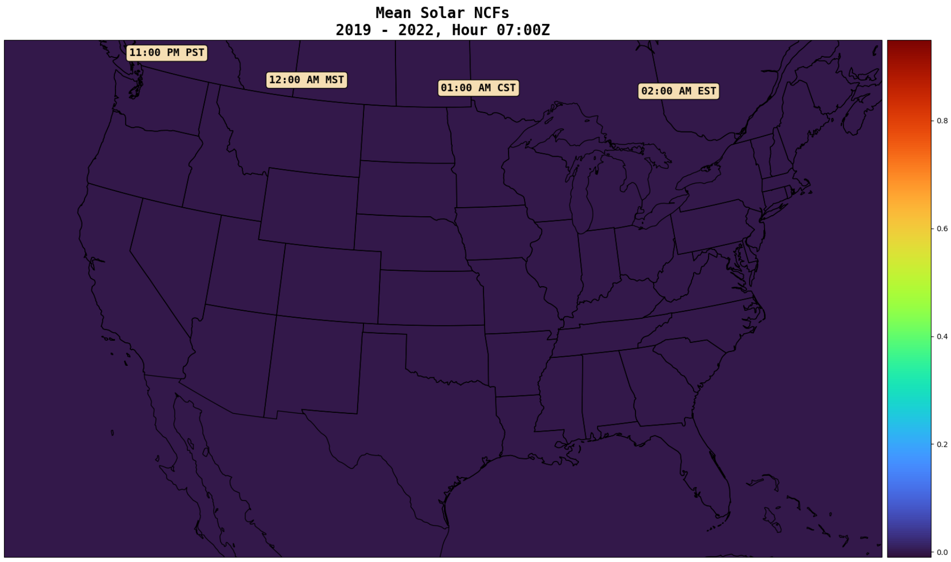

Figure B-20: Mean Solar NCF - Hour 07Z

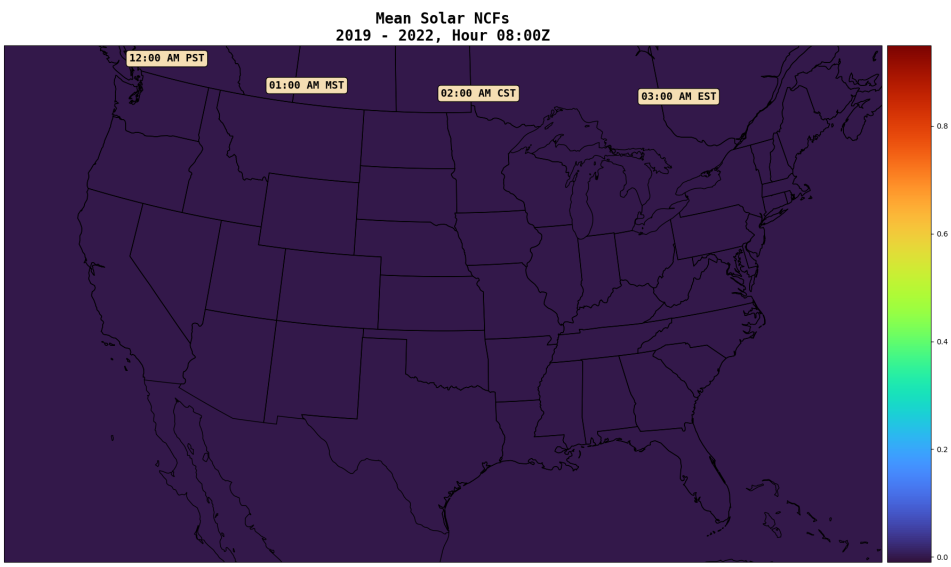

Figure B-21: Mean Solar NCF - Hour 08Z

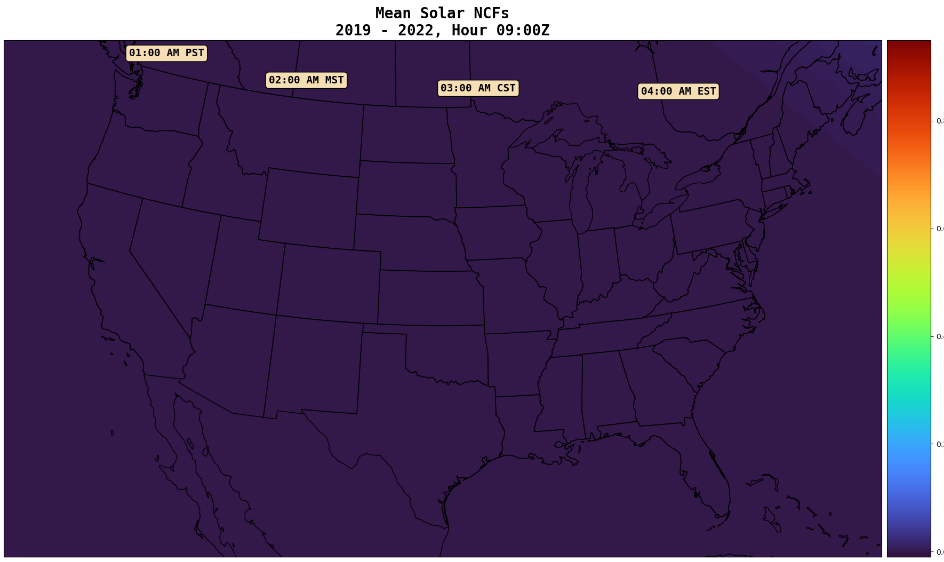

Figure B-22: Mean Solar NCF - Hour 09Z

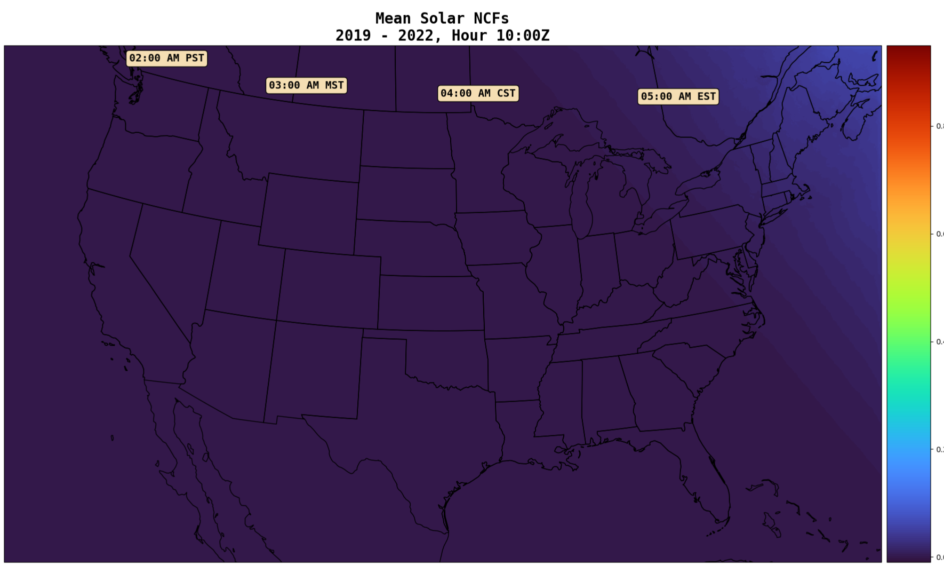

Figure B-23: Mean Solar NCF - Hour 10Z

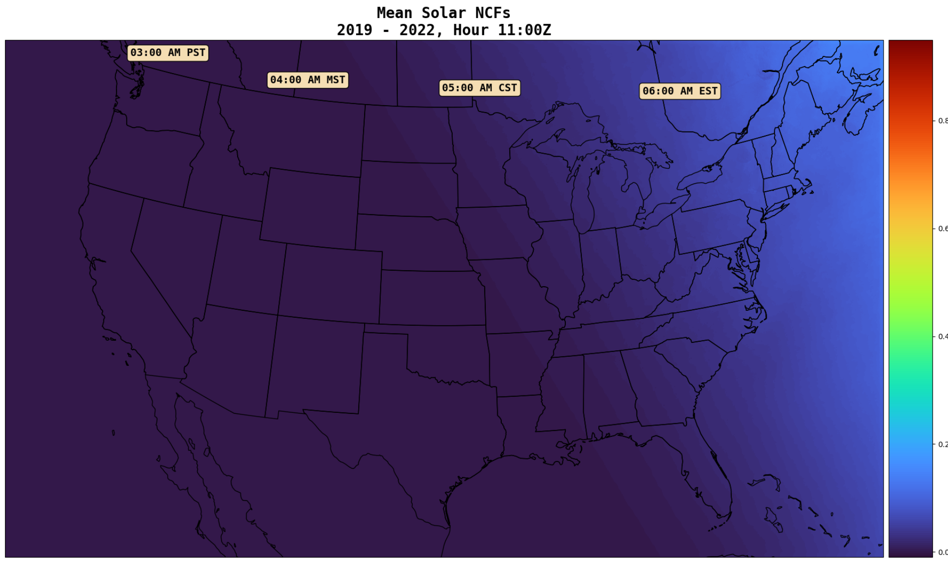

Figure B-24: Mean Solar NCF - Hour 11Z

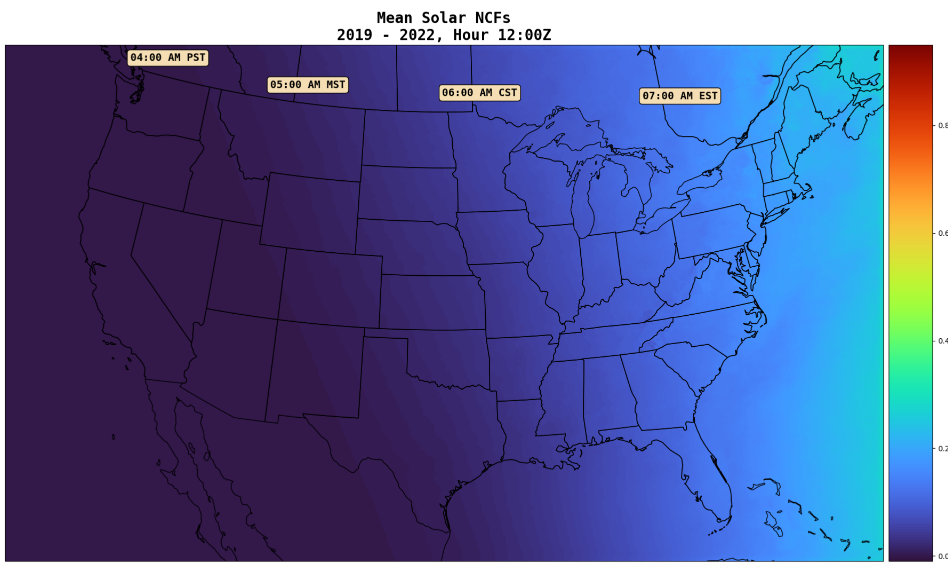

Figure B-25: Mean Solar NCF - Hour 12Z

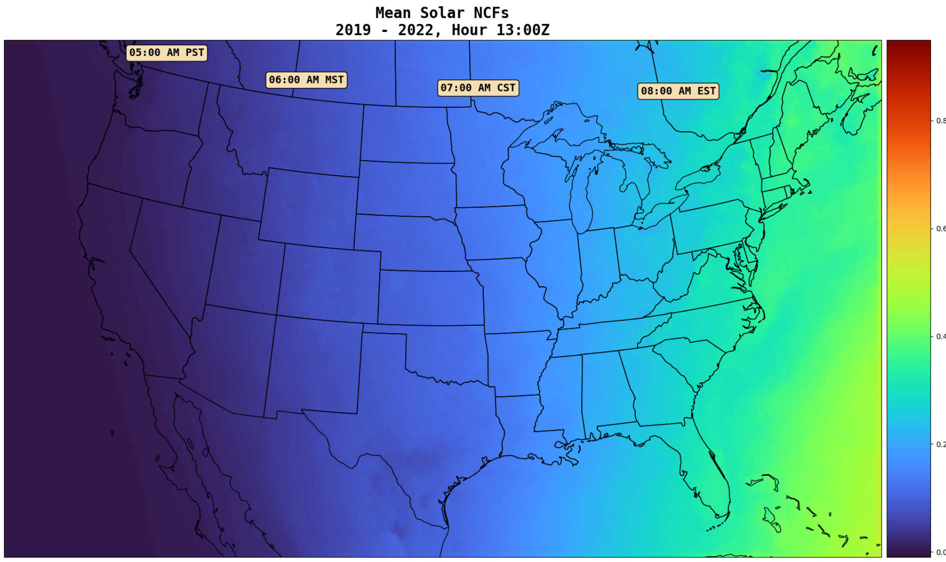

Figure B-26: Mean Solar NCF - Hour 13Z

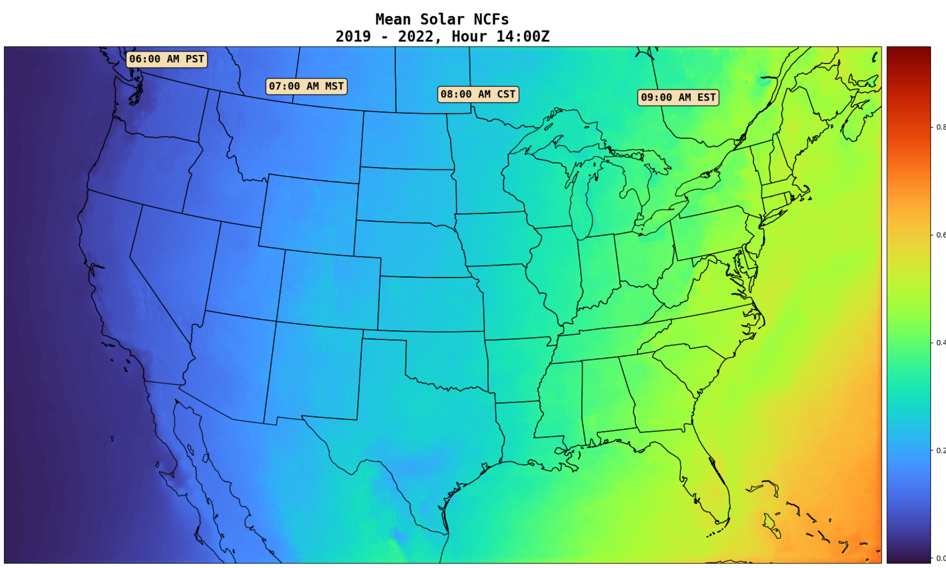

Figure B-27: Mean Solar NCF - Hour 14Z

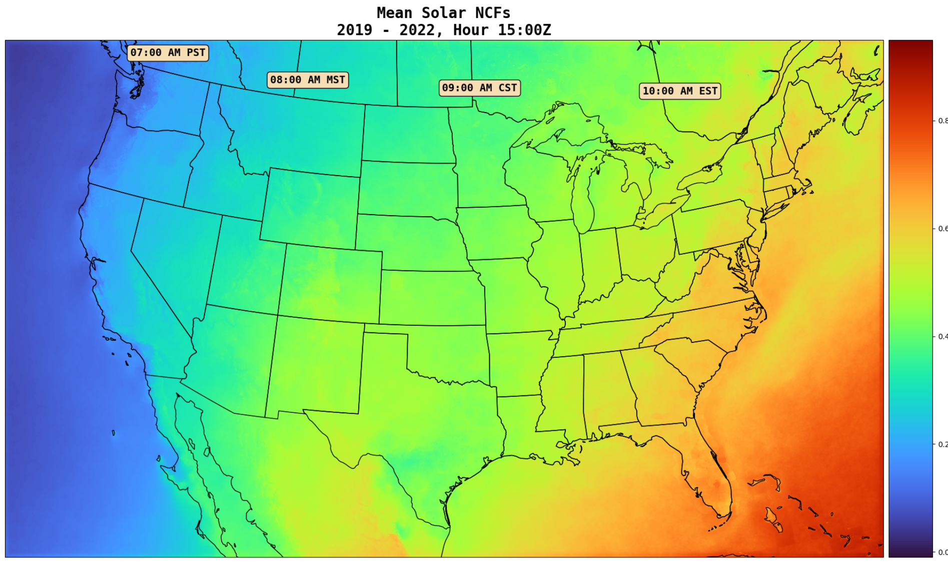

Figure B-28: Mean Solar NCF - Hour 15Z

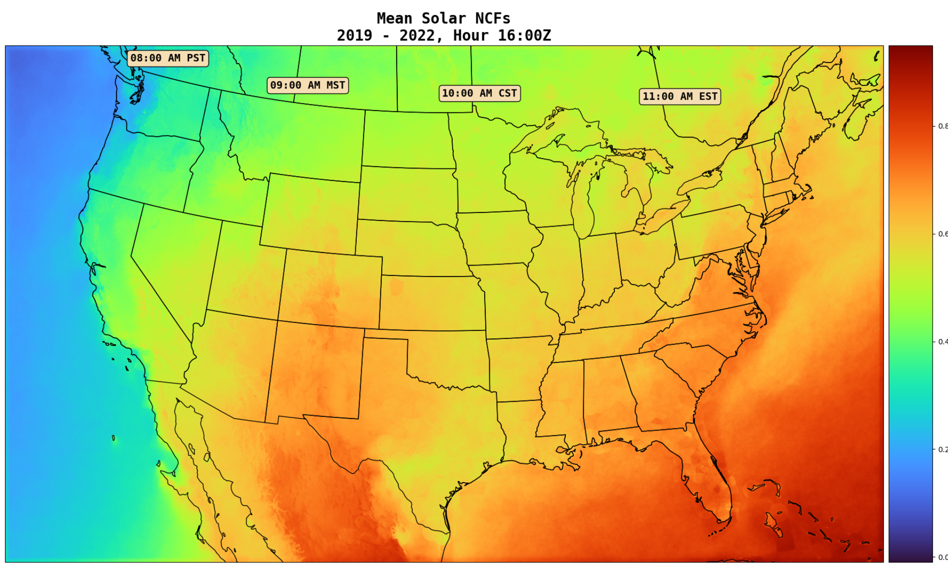

Figure B-29: Mean Solar NCF - Hour 16Z

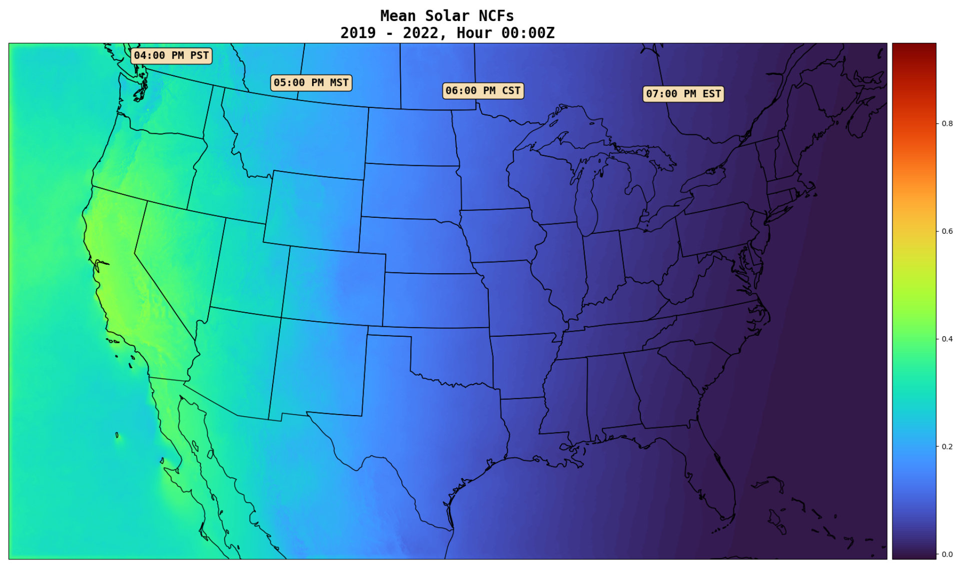

Figure B-30: Mean Solar NCF - Hour 17Z

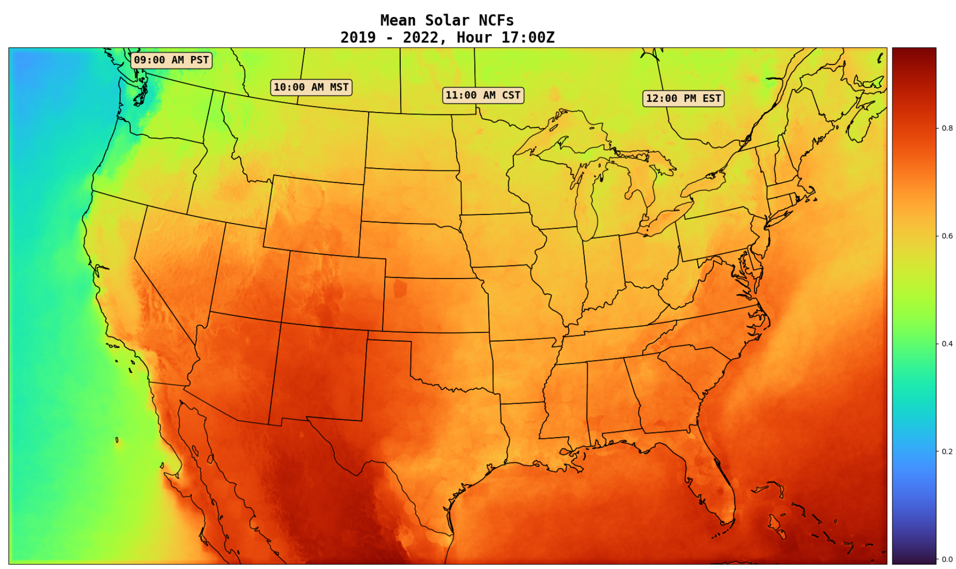

Figure B-31: Mean Solar NCF - Hour 17Z

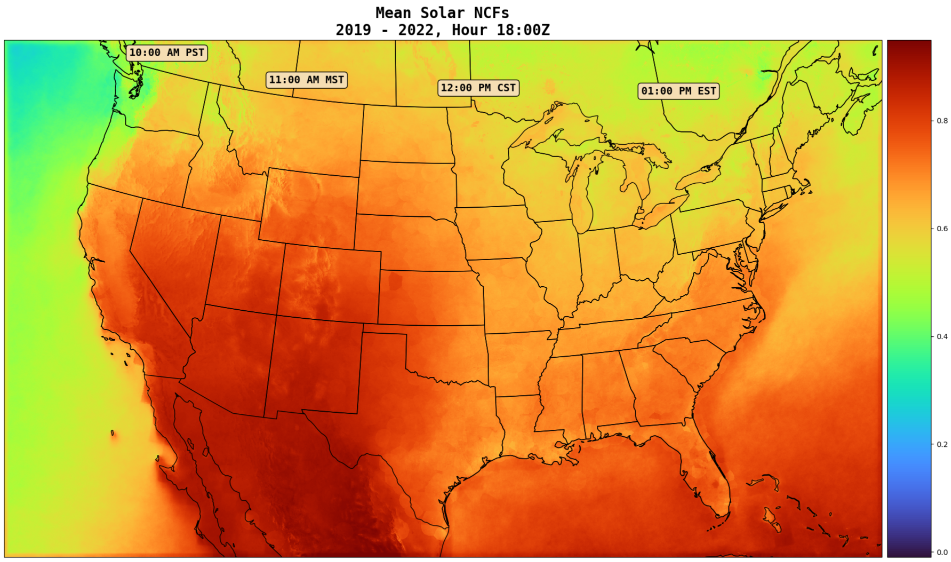

Figure B-32: Mean Solar NCF - Hour 18Z

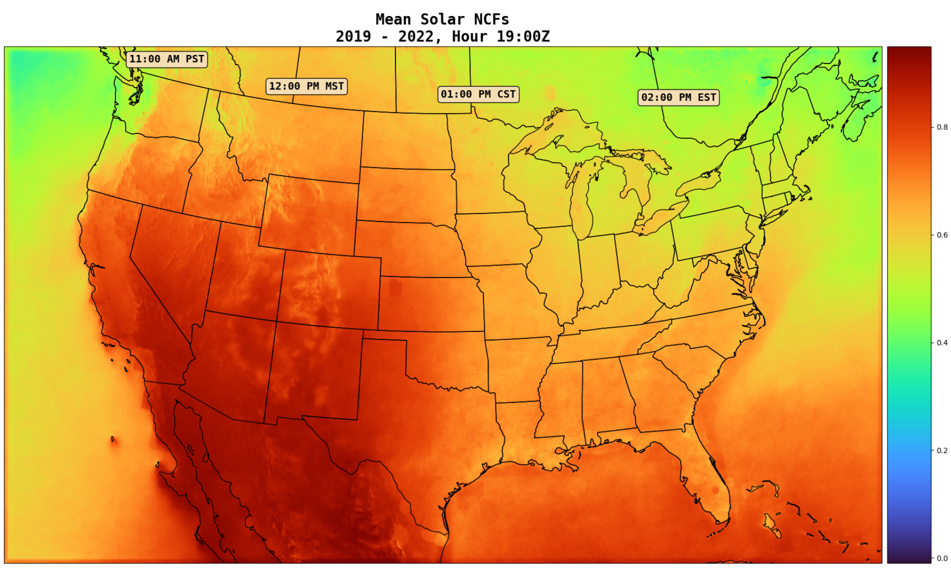

Figure B-33: Mean Solar NCF - Hour 19Z

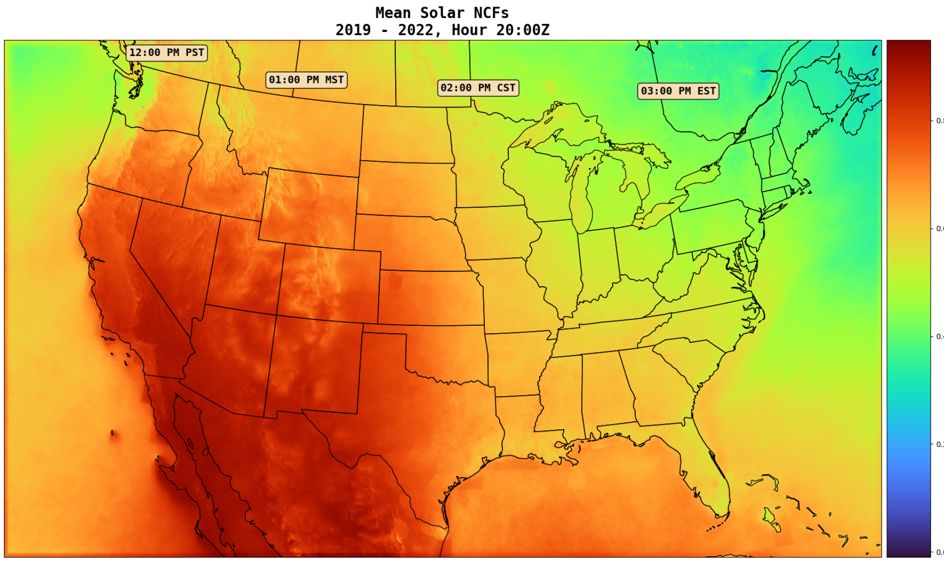

Figure B-34: Mean Solar NCF - Hour 20Z

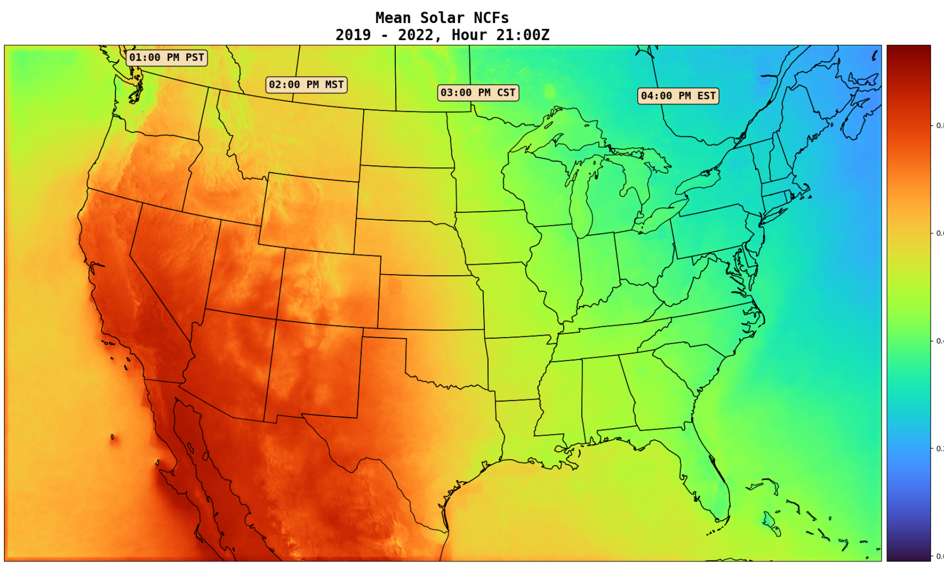

Figure B-35: Mean Solar NCF - Hour 21Z

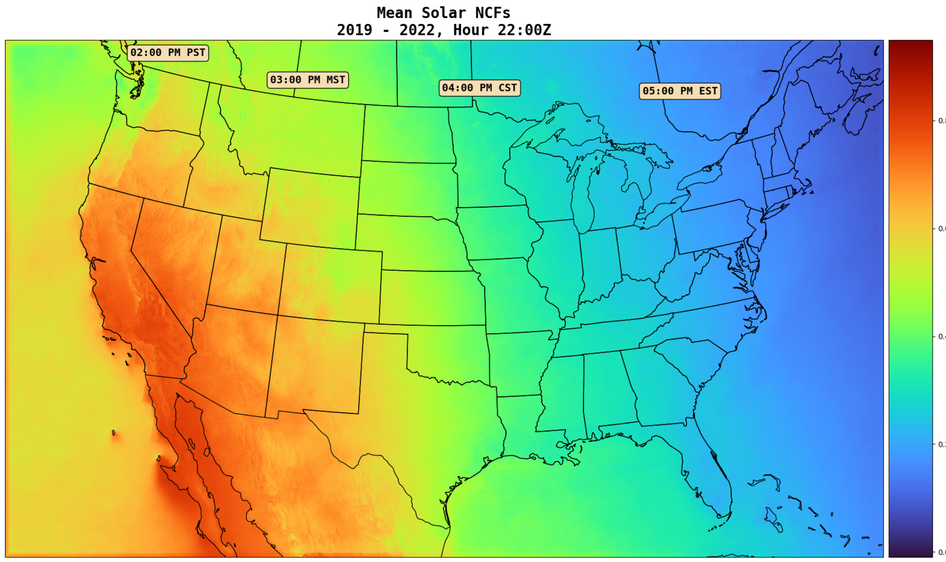

Figure B-36: Mean Solar NCF - Hour 22Z

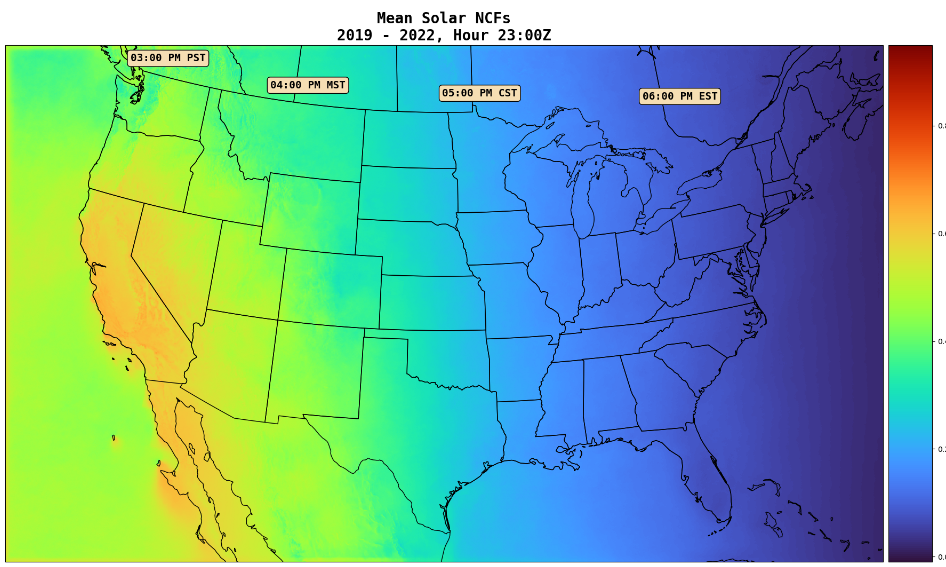

Figure B-37: Mean Solar NCF - Hour 23Z

Appendix C

Power Price Seasonality

C.1 Monthly Seasonality

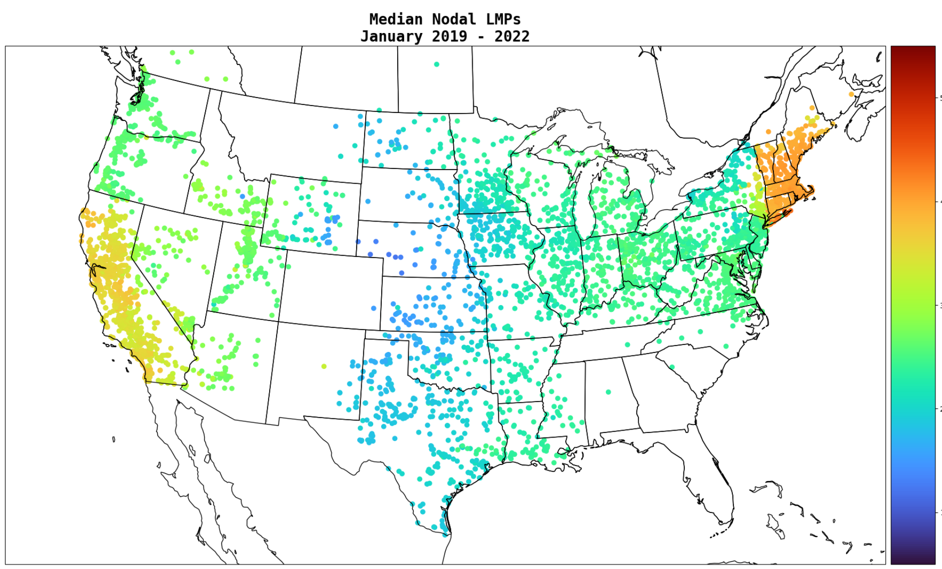

Figure C-1: Median Wind NCF - January

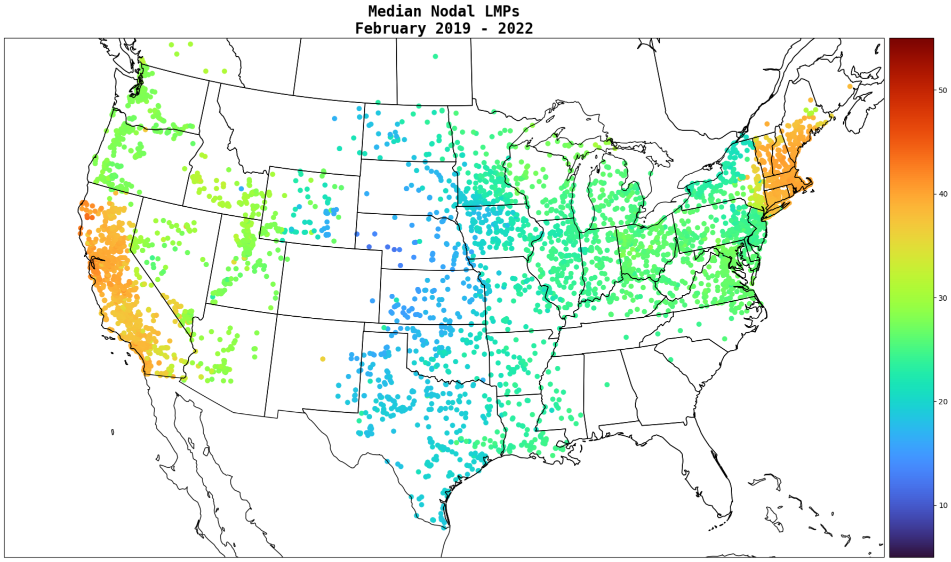

Figure C-2: Median Wind NCF - Febuary

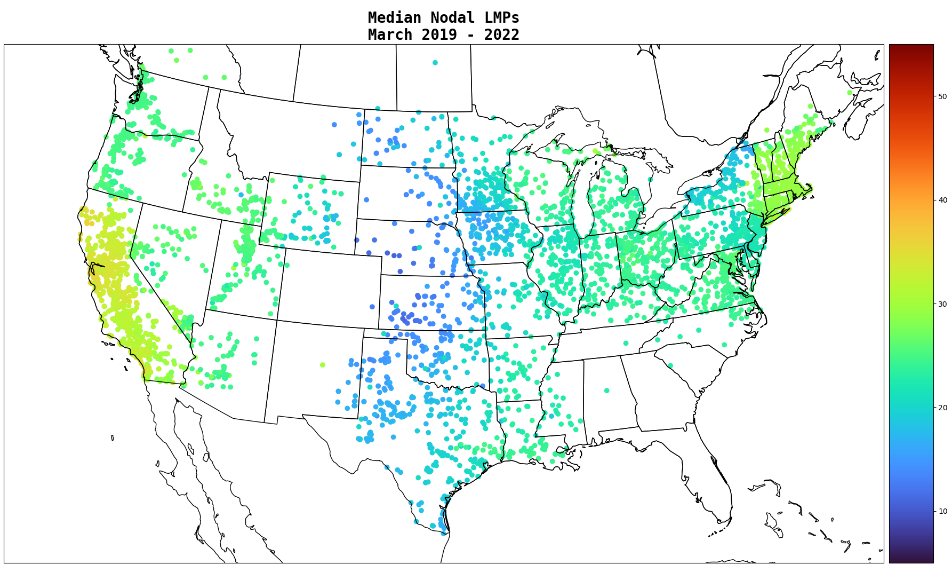

Figure C-3: Median Wind NCF - March

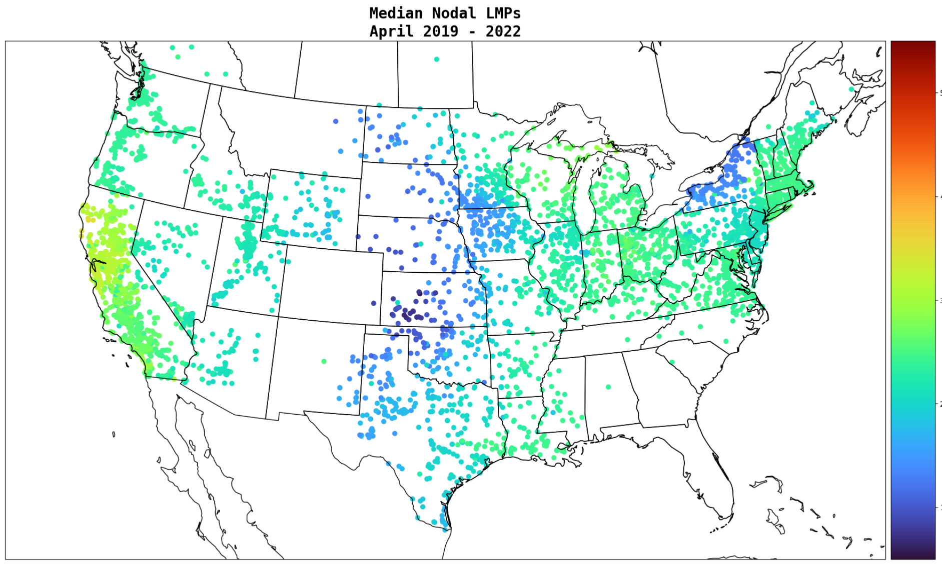

Figure C-4: Median Wind NCF - April

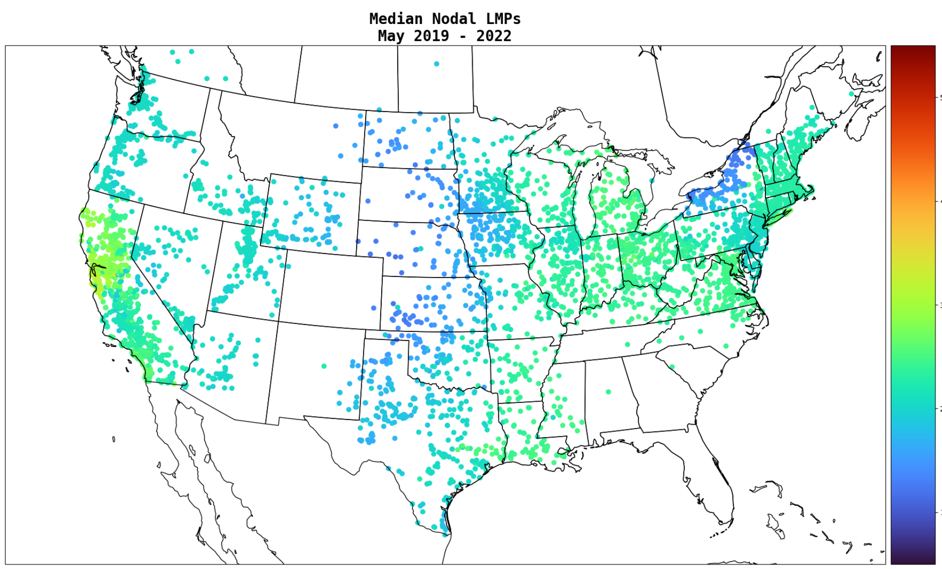

Figure C-5: Median Wind NCF - May

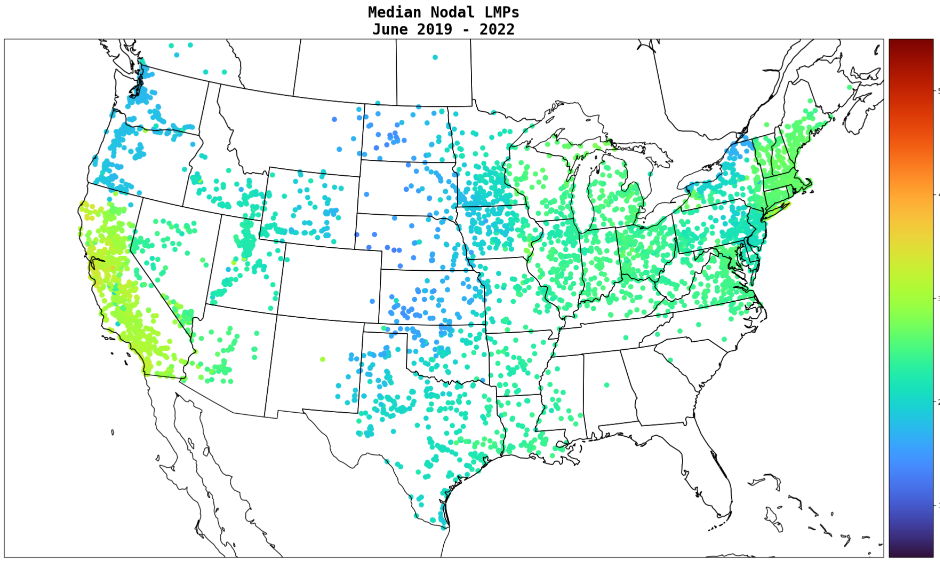

Figure C-6: Median Wind NCF - June

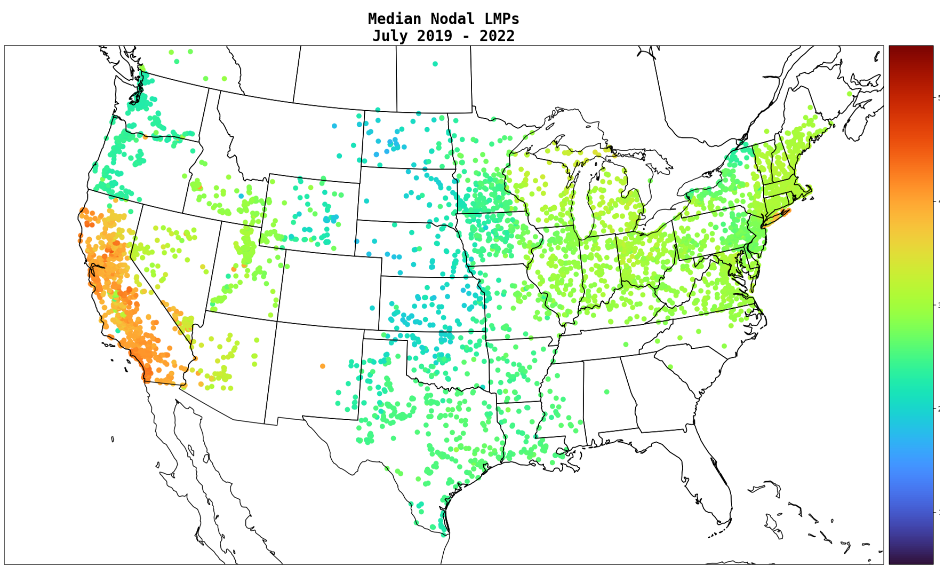

Figure C-7: Median Wind NCF - July

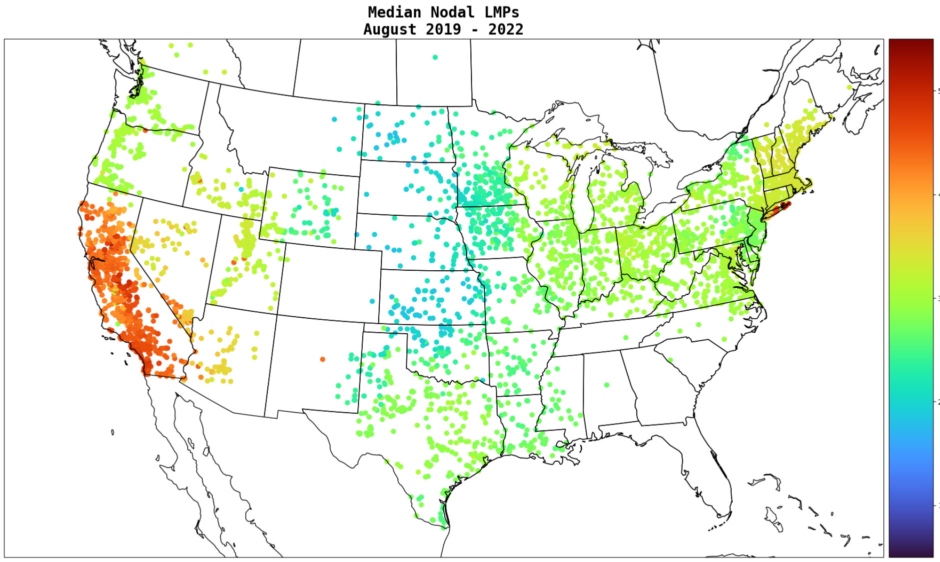

Figure C-8: Median Wind NCF - August

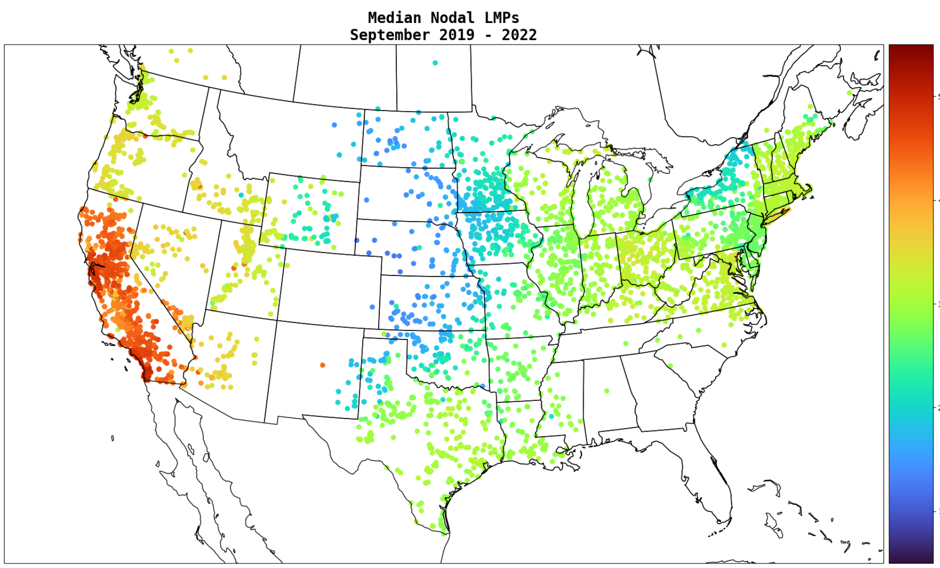

Figure C-9: Median Wind NCF - September

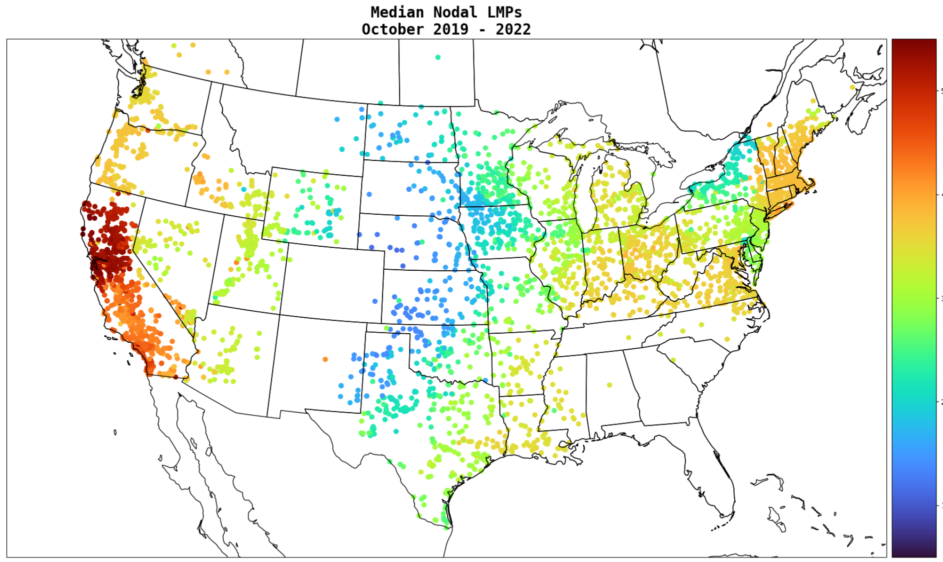

Figure C-10: Median Wind NCF - October

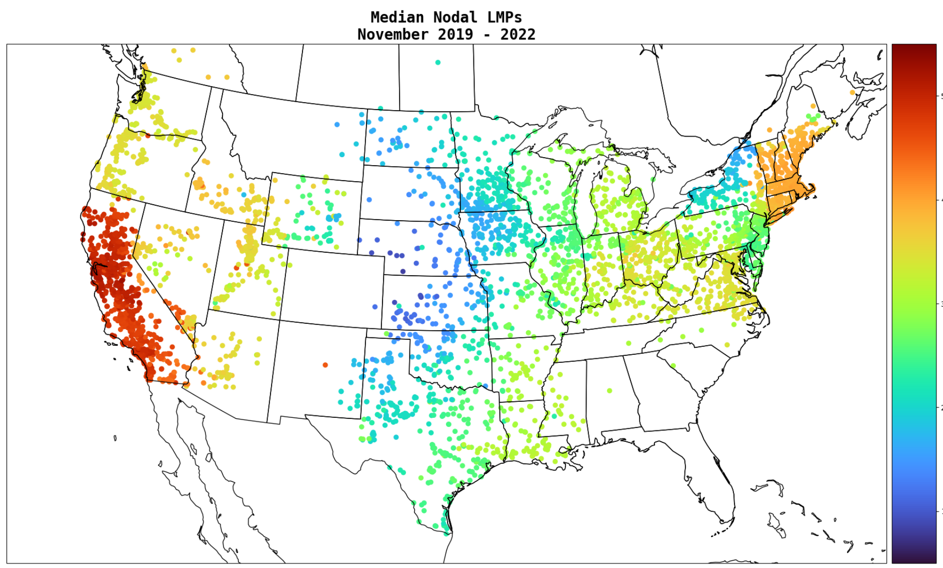

Figure C-11: Median Wind NCF - November

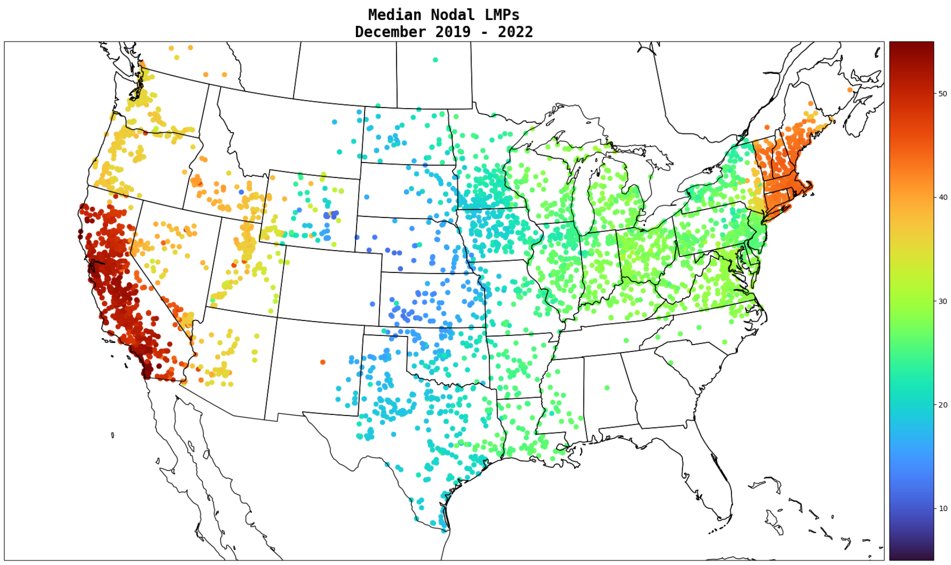

Figure C-12: Median Wind NCF - December

C.2 Hourly Seasonality

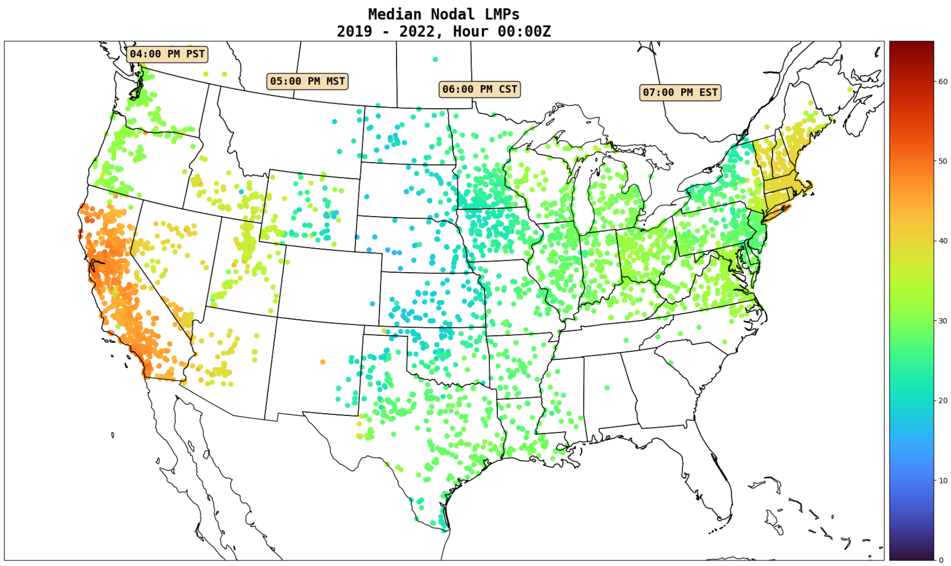

Figure C-13: Median Wind NCF - Hour 00Z

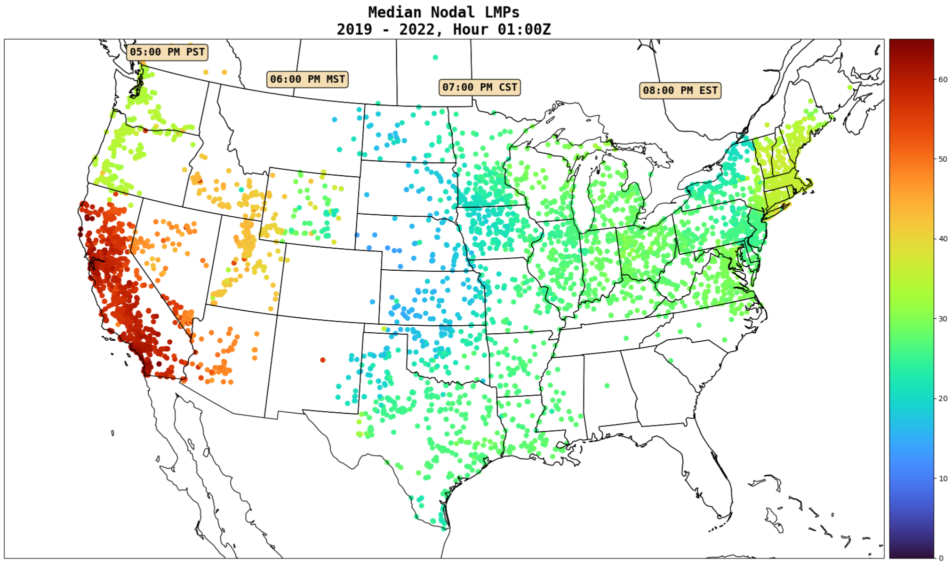

Figure C-14: Median Wind NCF - Hour 01Z

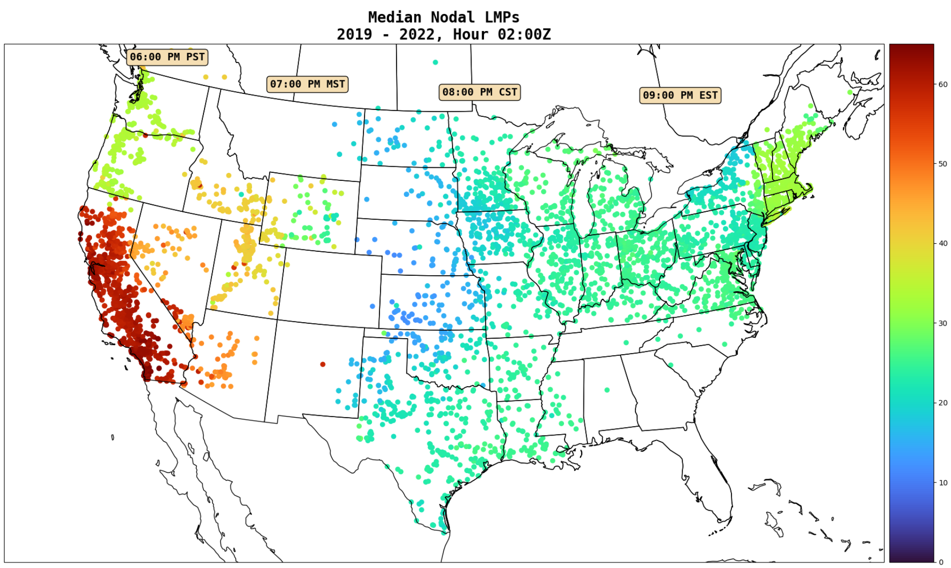

Figure C-15: Median Wind NCF - Hour 02Z

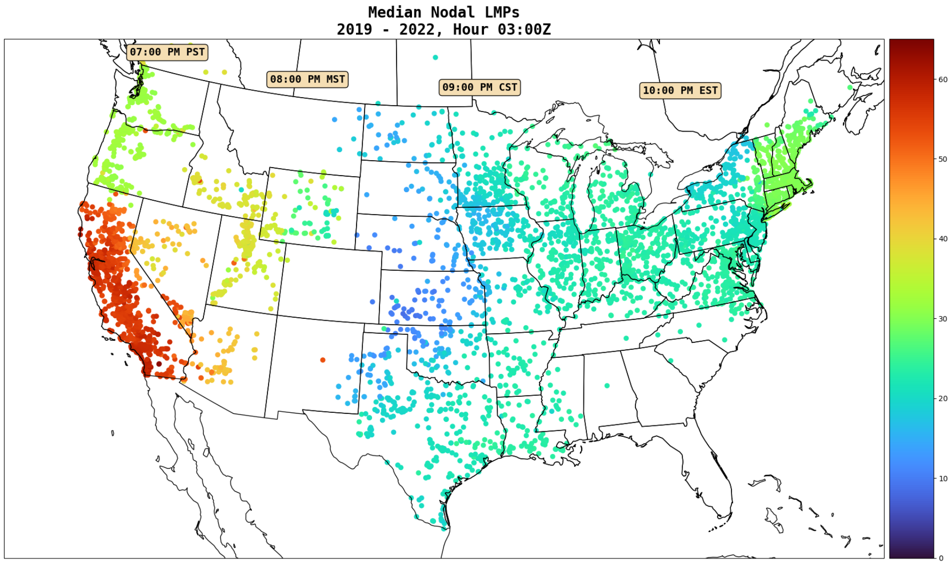

Figure C-16: Median Wind NCF - Hour 03Z

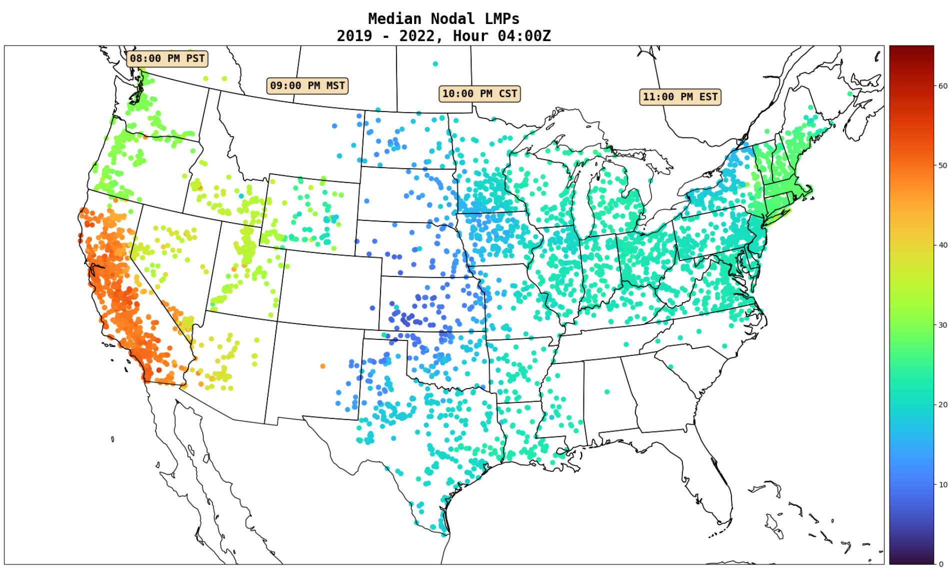

Figure C-17: Median Wind NCF - Hour 04Z

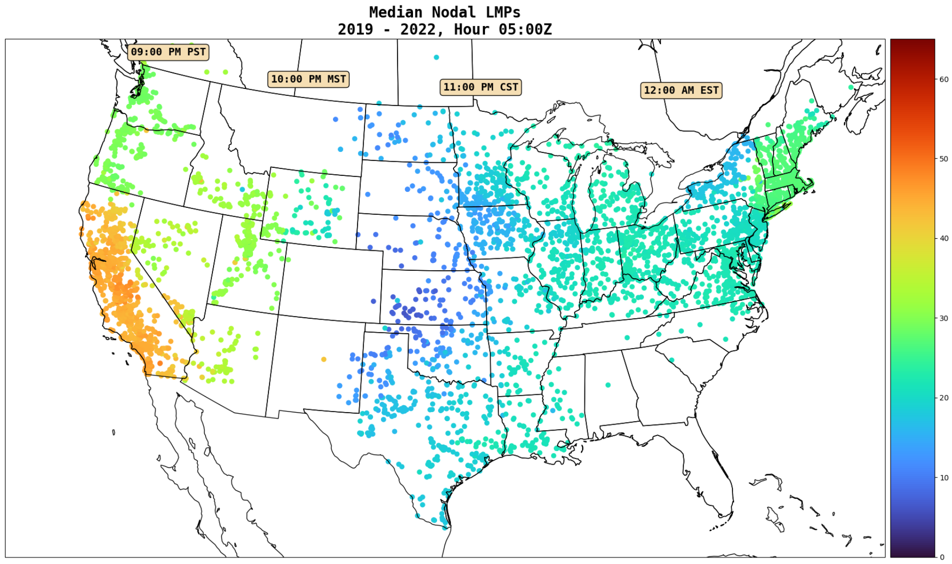

Figure C-18: Median Wind NCF - Hour 05Z

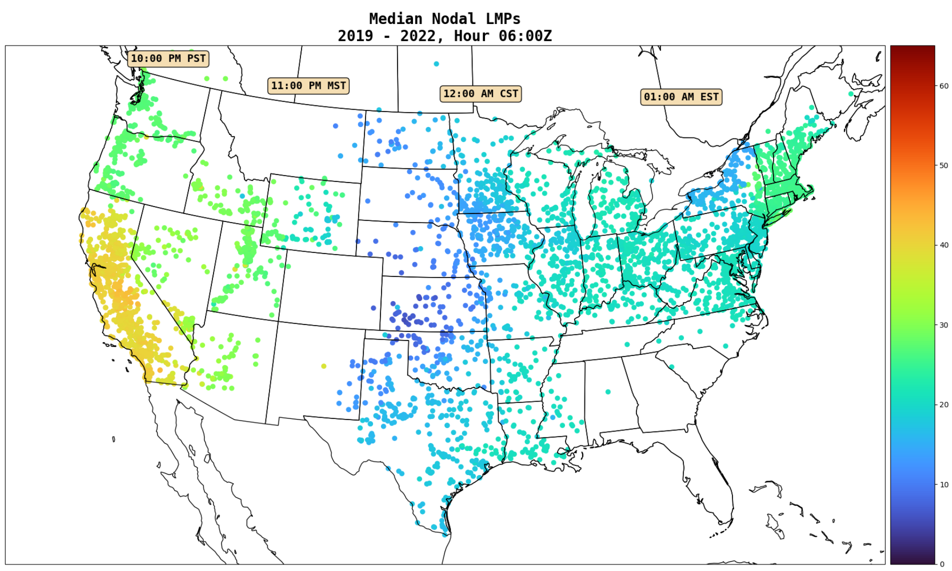

Figure C-19: Median Wind NCF - Hour 06Z

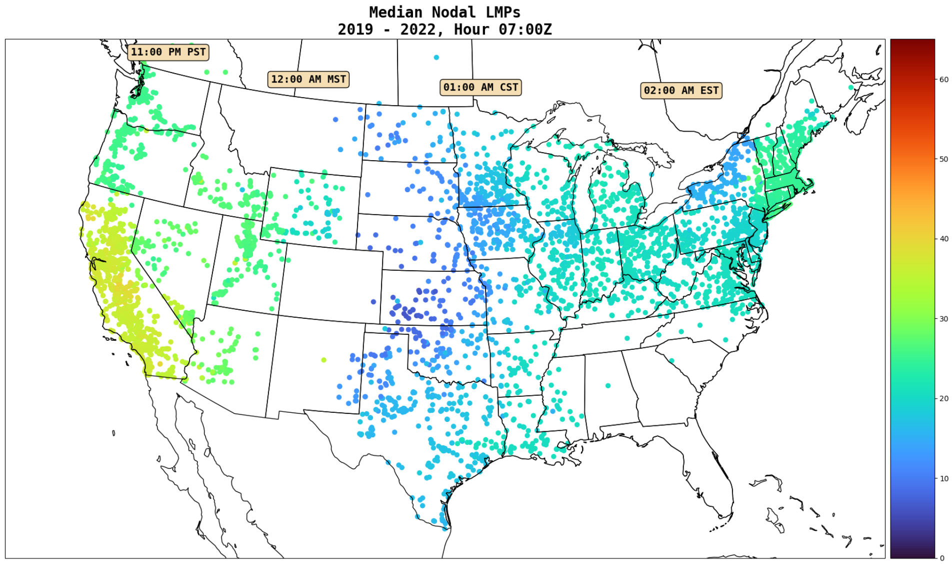

Figure C-20: Median Wind NCF - Hour 07Z

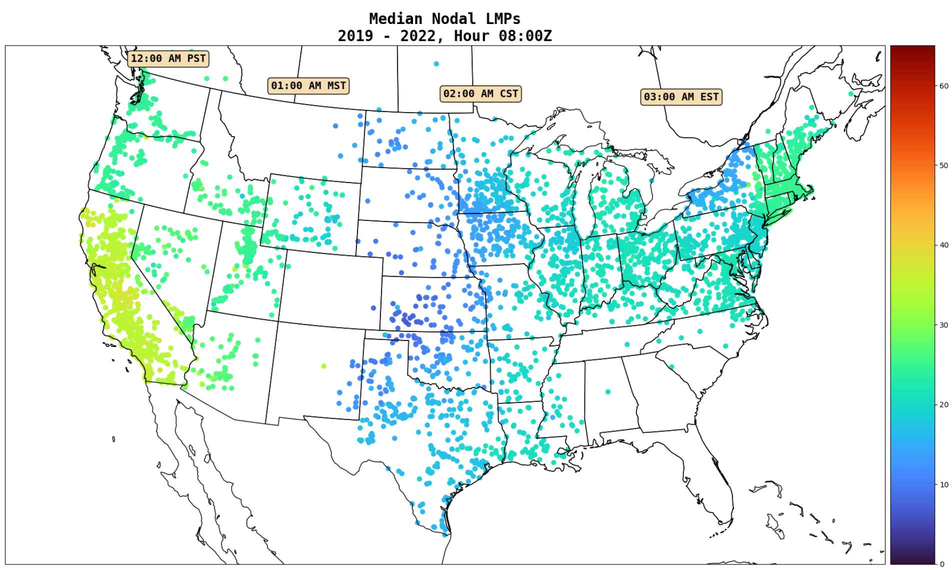

Figure C-21: Median Wind NCF - Hour 08Z

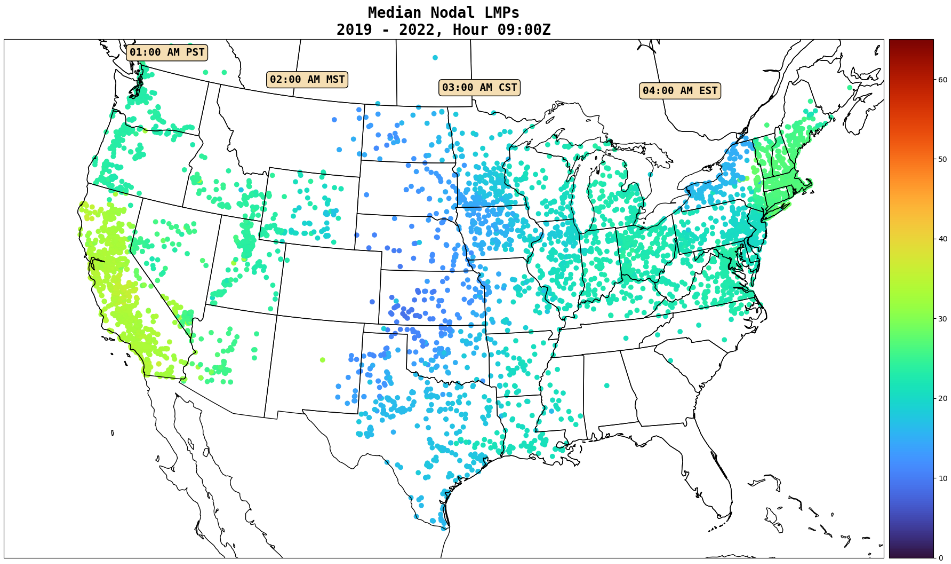

Figure C-22: Median Wind NCF - Hour 09Z

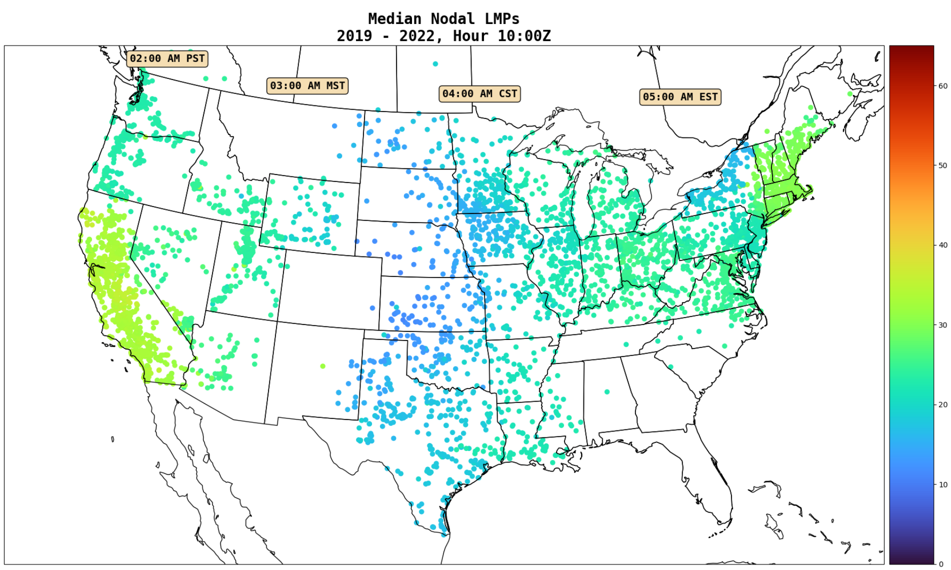

Figure C-23: Median Wind NCF - Hour 10Z

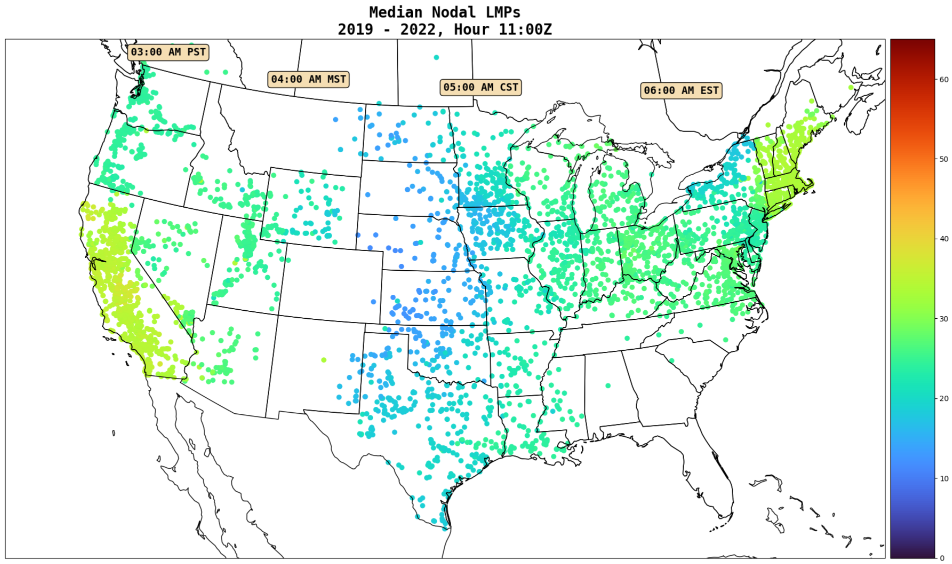

Figure C-24: Median Wind NCF - Hour 11Z

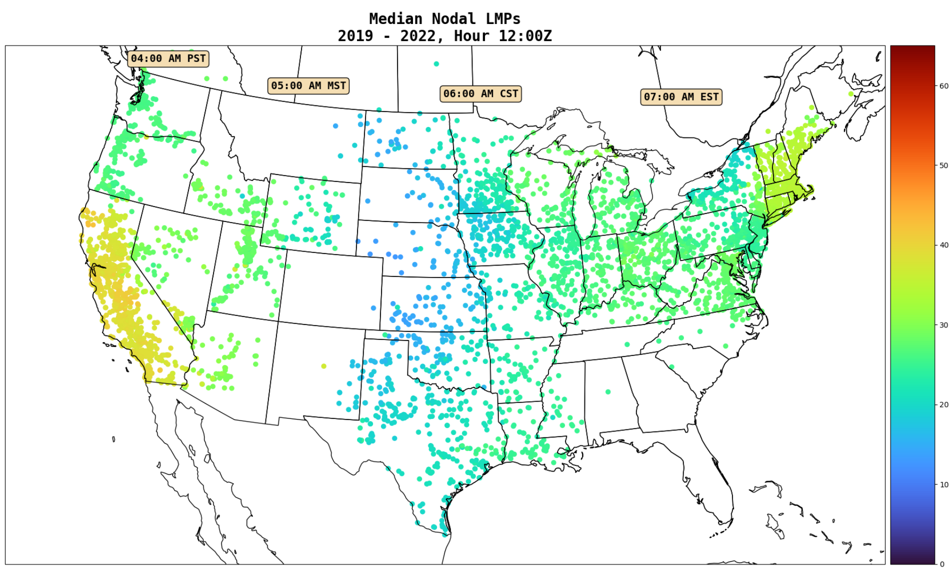

Figure C-25: Median Wind NCF - Hour 12Z

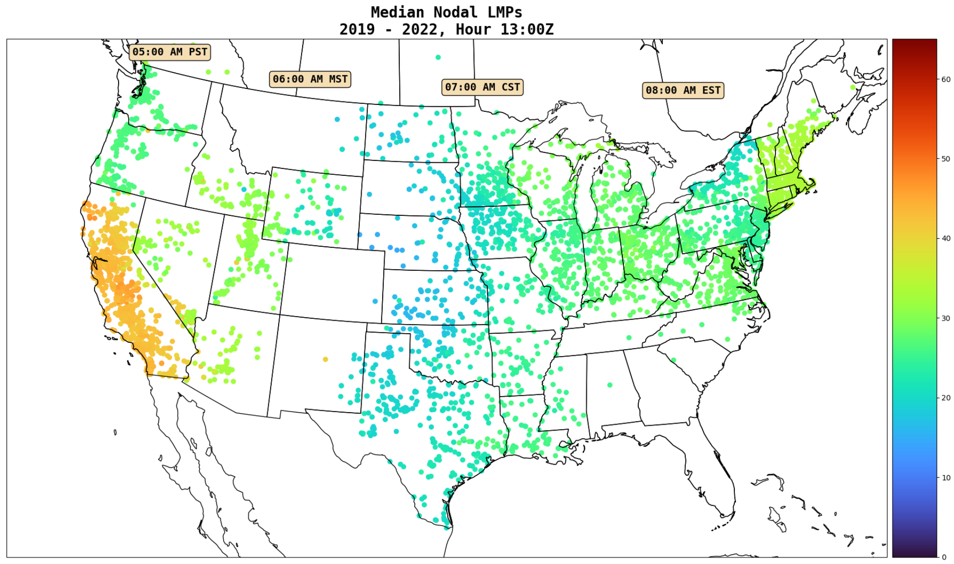

Figure C-26: Median Wind NCF - Hour 13Z

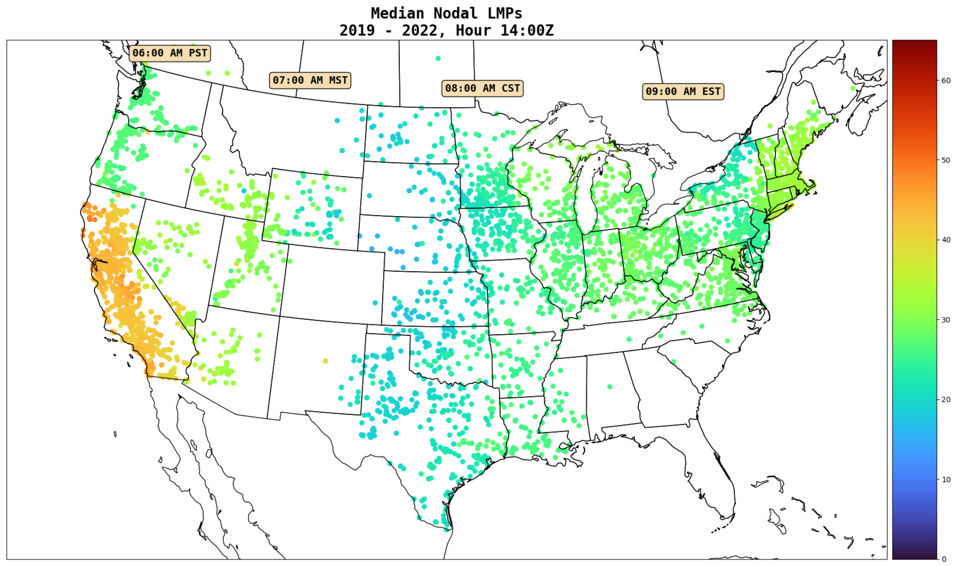

Figure C-27: Median Wind NCF - Hour 14Z

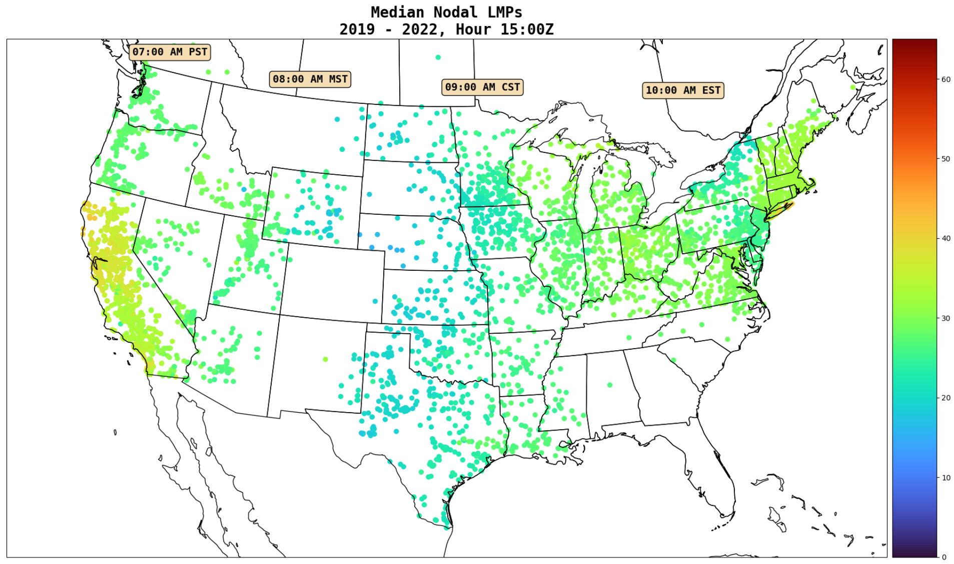

Figure C-28: Median Wind NCF - Hour 15Z

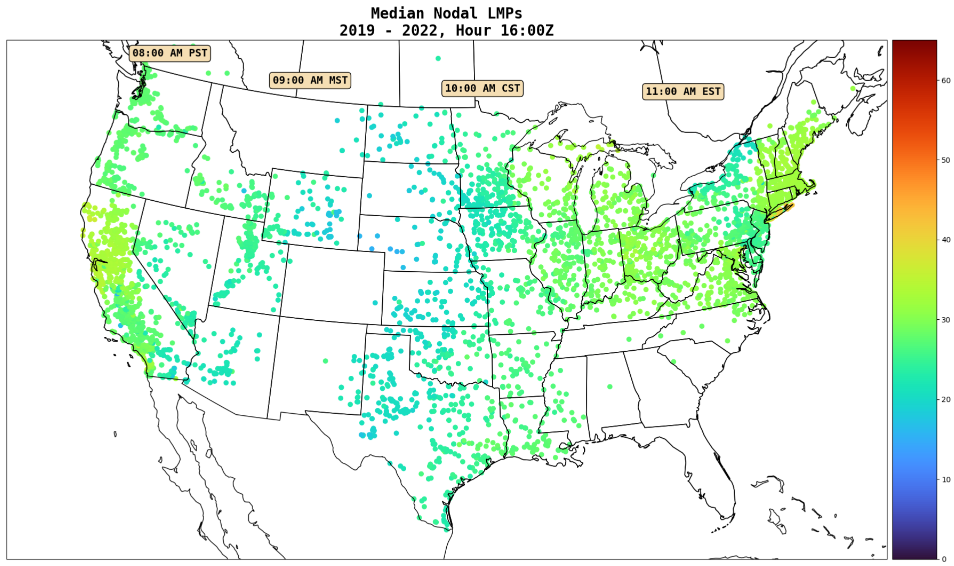

Figure C-29: Median Wind NCF - Hour 16Z

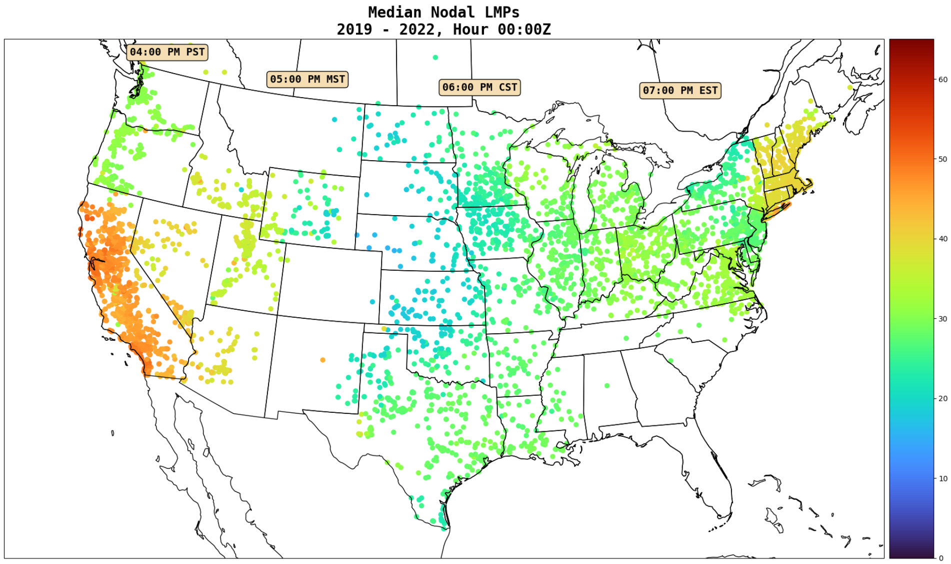

Figure C-30: Median Wind NCF - Hour 17Z

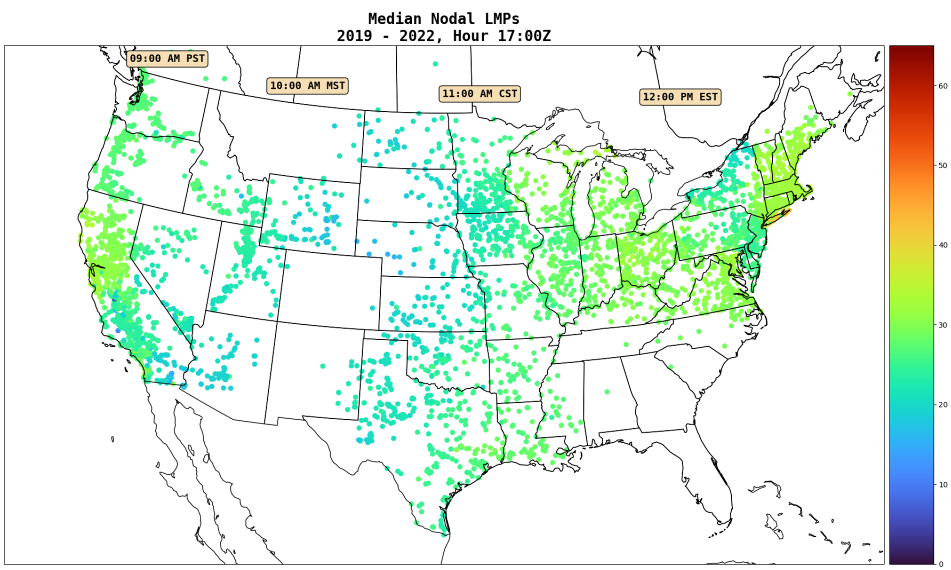

Figure C-31: Median Wind NCF - Hour 17Z

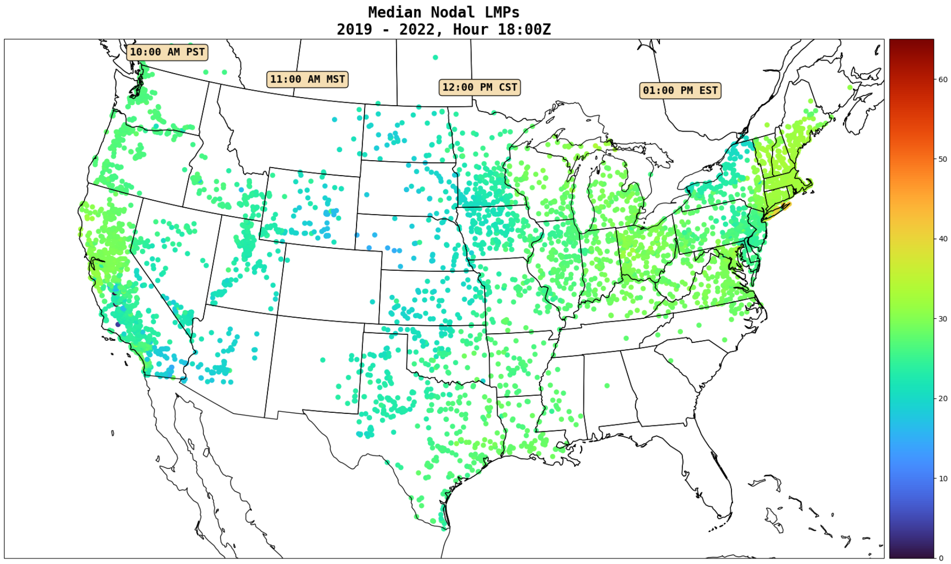

Figure C-32: Median Wind NCF - Hour 18Z

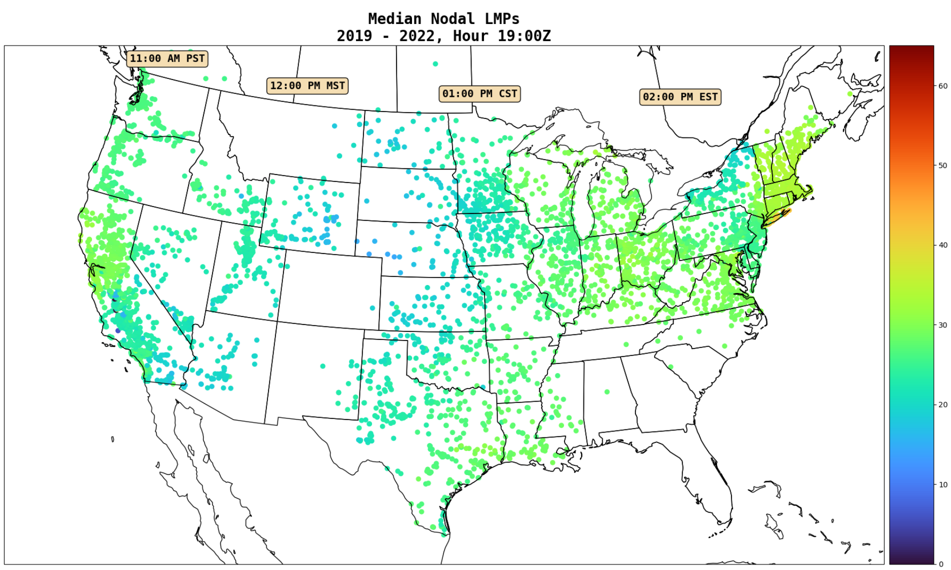

Figure C-33: Median Wind NCF - Hour 19Z

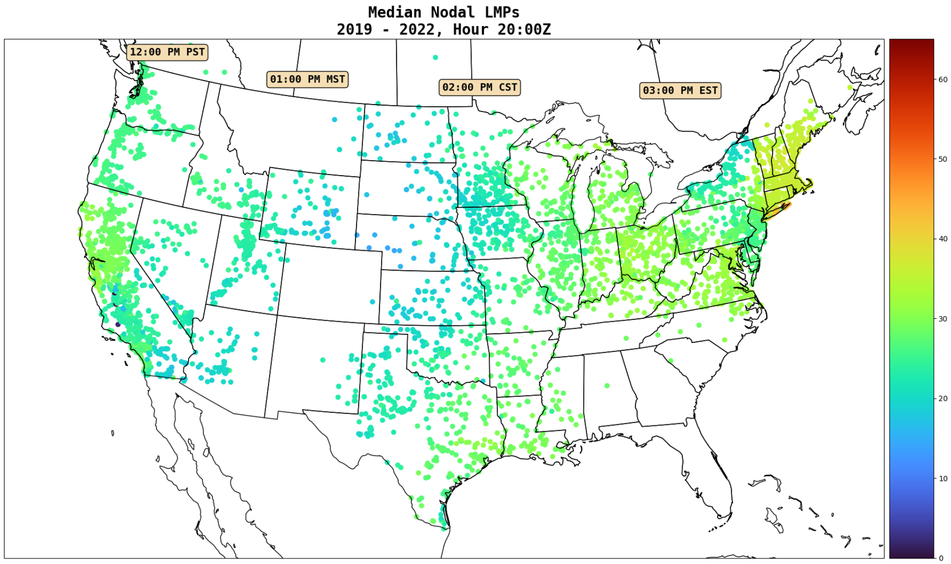

Figure C-34: Median Wind NCF - Hour 20Z

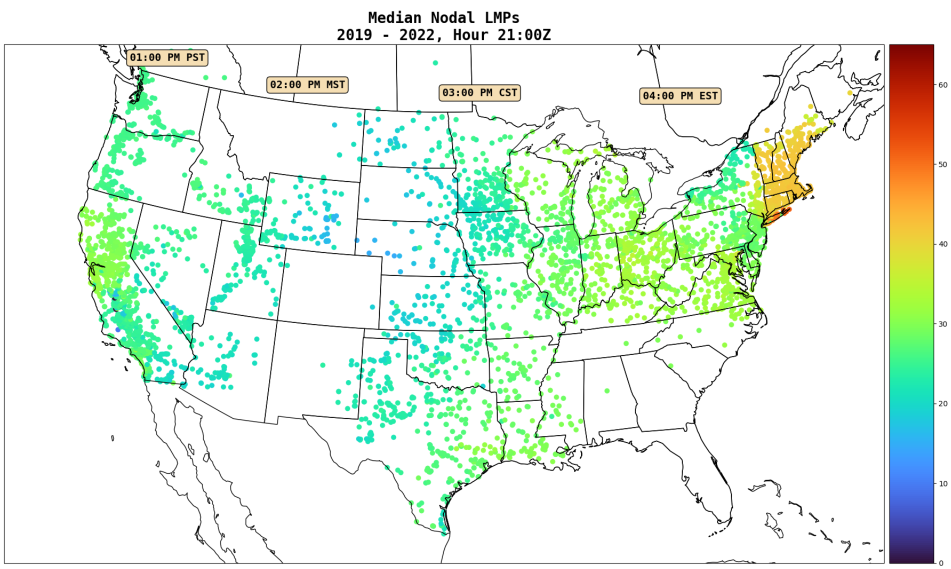

Figure C-35: Median Wind NCF - Hour 21Z

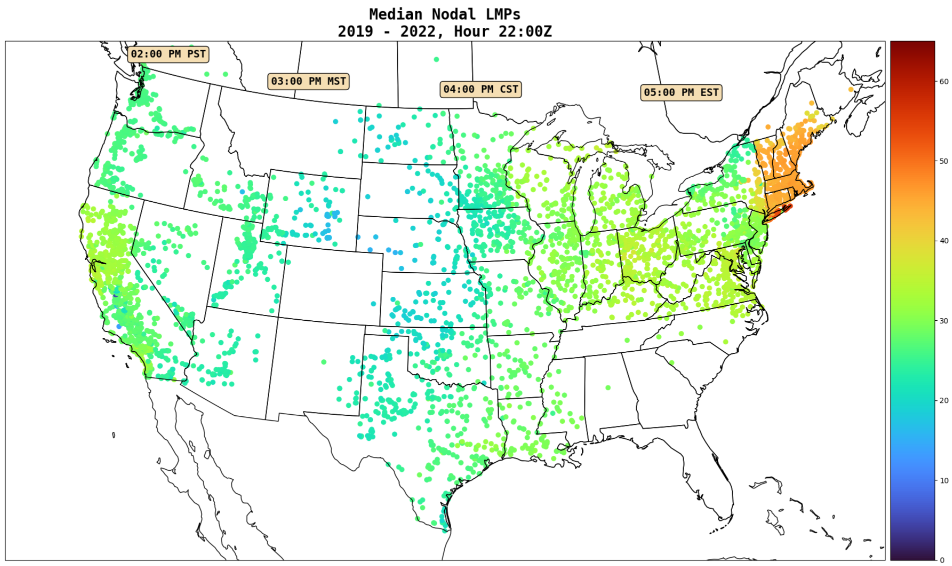

Figure C-36: Median Wind NCF - Hour 22Z

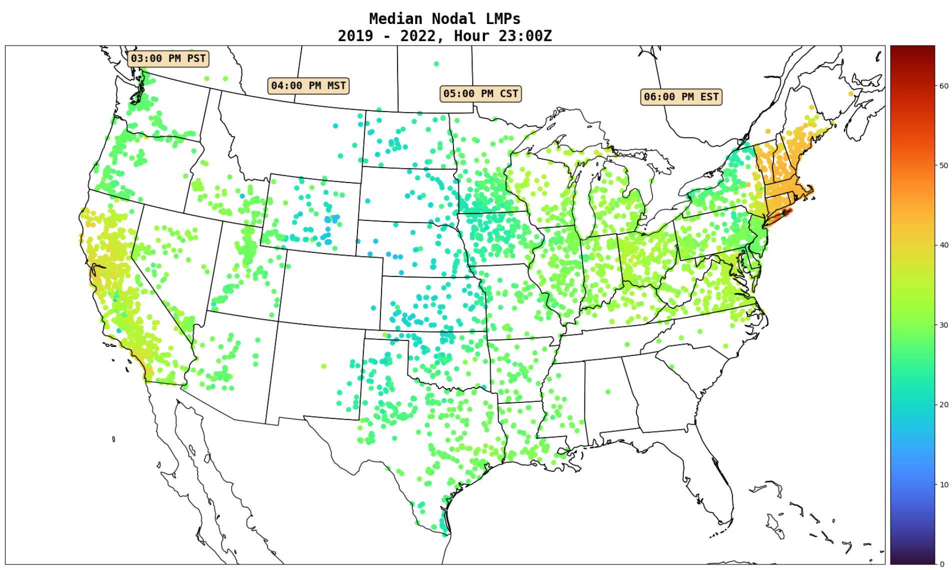

Figure C-37: Median Wind NCF - Hour 23Z

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