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PPRP

WIS:dom-P Model Setup

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MARYLAND POWER PLANT
RESEARCH PROGRAM

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TABLE OF CONTENTS

PAGE

APPENDIX D. WIS:dom-P Model Setup

WIS:dom®-P is a fully combined capacity expansion and production cost model. For a detailed, technical description of the model, please see VCE's online technical documentation.[1] The following text briefly describes several key setup features of the model.

Model Utility/Distributed Grid Co-Optimization and Reliability Overview

A unique feature of WIS:dom-P is its ability to model the utility-scale electricity grid with detailed granularity over large spatial domains. Additionally, the model co-optimizes and coordinates the utility grid with the distribution grid. This capability was incorporated into all of the scenarios. The tractability of such a co-optimization requires parameterization of all the distribution-level grid topology and infrastructure. Because of computational limitations, WIS:dom-P disaggregates the DER technologies but aggregates the distribution lines and other infrastructure as an interface (or "grid edge") that electricity must pass across. The model does assign costs and can compute inferred capacities and distances from the solutions, but it cannot (with current computation power) resolve explicitly all the distribution infrastructure in a disaggregated manner.

The main components of deriving the utility-distribution (U-D) interface are:

1. Utility-observed peak distribution demand;
2. Utility-observed peak distribution generation; and
3. Utility-observed distribution electricity consumption.

The definition of "utility-observed" is the appearance of the metric at a 69-kV transmission substation or above. Below 69 kV, the model is implicitly solving with combinations of DERs, and what remains is exposed to the utility-scale grid at the substation. **Figure D-1** is a schematic of how WIS:dom-P represents the U-D interface, and **Figure D-2** displays an illustration of how the distribution co-optimization results in two distinct concerts playing out: DERs coordinating to reshape the demand exposed to the utility-scale (load shifting to supply) and utility-scale generation and transmission coordinating to serve the demand that appears at the 69-kV substation (supply shifting to load).

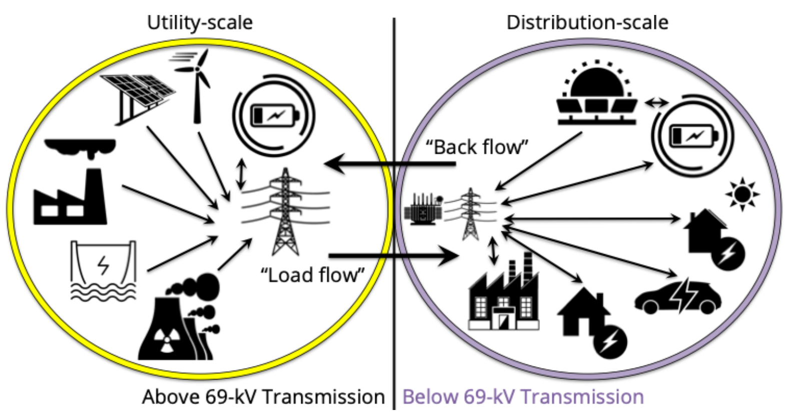

Figure D-1. A schematic picture of the U-D interface within the WIS:dom-P modeling platform.

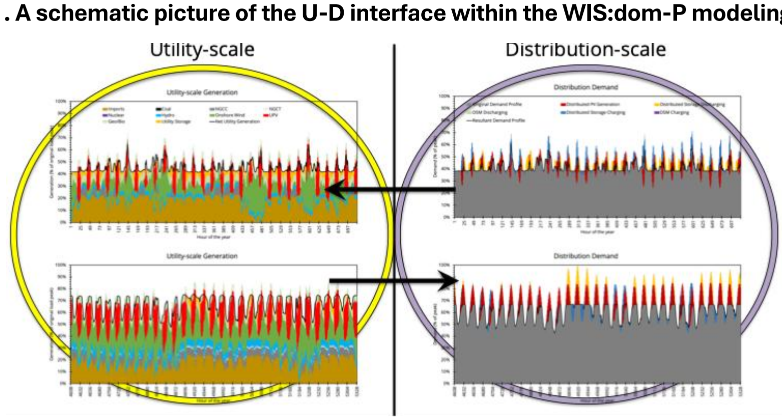

Figure D-2. Example coordination at the utility- and distribution-scale within the WIS:dom-P model.

[1] https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf.

Generating an interface for the modeling requires the parameterization of the three components enumerated above. The basic equations that define the U-D interface are further documented in the online technical documentation for WIS:dom-P.[2] This direct link provides more cost details on the objective function with respect to the distribution infrastructure requirements that result in changes in model logic to find the least-cost system. The U-D interface equations are relatively simple but have a direct influence on a substantial number of variables, and can result in a completely different solution space being accessible to WIS:dom-P compared with other models that do not solve for the co-optimization of the distribution grid.

As part of the optimal capacity expansion, WIS:dom-P must ensure each grid meets reliability constraints through enforcing the planning reserve margins specified by the North American Electric Reliability Corporation (NERC) and by having a 7% load following reserve available at all times. There is no loss of load at any time.

Objective Function

The WIS:dom-P optimization model is typically run in linear programming mode. This means that the equations and constraints are all described as linear (and convex) relaxation formulations.[3] The objective function of WIS:dom-P is to minimize the total system cost for a given construct of constraints and sectoral coupling. The total system cost includes amortized generator capital expenditures, fuel costs, startup and shutdown costs, amortized transmission capital expenditures, amortized storage capital expenditures, variable operations and maintenance (O&M) expenditures, fixed O&M expenditures, amortized natural gas transport expenditures, transmission wheeling charges, transmission access charges, interconnection expenditures, demand-side management and demand response expenditures, distribution costs and access charges, curtailment charges, reserve costs, retirement costs, and international trading costs. For additional information about model formulation, including mathematical formulations, see the online technical documentation for WIS:dom-P.[4]

VCE Datasets & WIS:dom-P Inputs

The subsequent overview describes certain analyses undertaken, inputs adopted, and assumptions made for purposes of Exeter and VCE's study of 100% RPS and CES requirements. For reasons documented in the main report, the modeling process entailed two distinct "Phases." The modeling approach differed in some ways for each Phase. Most of these differences were intended to reflect changing conditions (e.g., Pennsylvania's withdrawal from RGGI) or incorporate feedback provided in response to the initial models (e.g., treatment of Maryland Climate Solutions Now Act [CSNA] emission targets as requirements rather than goals). Differences between the Phase 1 and Phase 2 models are identified below, as applicable. Due to the acquisition of VCE during the project, the level of documentation available that describes the Phase 2 modeling approach is limited.

Generator Input Dataset

VCE processed the EIA annual data from the 2020 early release to create the baseline input generator dataset for this study. From this dataset, information for PJM as well as the entire State of Illinois was obtained for the Phase 1 model runs while information for all of the states in PJM, including areas of states that are not in PJM such as Kentucky and Tennessee, was processed for the Phase 2 model runs.

The WIS:dom-P generator input datasets are built upon the publicly available EIA 860 and EIA 923 data. VCE worked alongside Exeter to incorporate information from the PJM-GATS system into the input generator dataset for all scenarios for the State of Maryland. The EIA 860 only covers generators down to 1 MW in size. GATS helped fill in, at the county level, the distributed solar and geothermal heat pumps (GHP) installed across Maryland. Almost 700 MW of distributed solar and 1.8 MW of GHP in Maryland were represented from GATS. This alignment with GATS was only performed for Maryland since that is the main focus of this study. For the Phase 1 model runs, the EIA 860 2020 early release was used simply because that was the latest dataset available at the time of processing. VCE and Exeter did examine the changes between the 2020 early release and the full 2020 annual release from the EIA 860 once the latter was available. There was not enough of a difference to update the 2020 initialization year again. To help account for this, the monthly EIA 860 release from 2021, effectively providing what was installed by the end of 2021, was utilized to also constrain the 2021 investment year in the model. For the Phase 2 model runs, EIA data for 2021 was utilized.

With the custom changes included, VCE carried out several steps to align and aggregate technology types to the 3-km model grid space that matches the

[2] Ibid.
[3] There are mixed integer and non-linear formulations available within WIS:dom®-P; however, accuracy is not enhanced in an appreciable manner for capacity expansion studies considering the additional computational burden.
[4] https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf.

National Oceanic and Atmospheric Administration (NOAA) High-Resolution Rapid Refresh (HRRR).

The VCE process to prepare the generator input datasets is outlined below.

1. Data is merged, aligned, and concatenated between the EIA 860 and EIA 923 data.
2. Initial quality control is applied to the data to ensure accuracy between datasets. The work with Exeter incorporated the GATS data in this step.
3. Certain sites in PJM from the EIA 860 may visually appear outside of the designated PJM boundary for this study. Such sites were represented in their nearest PJM county within the same state.
4. The location of the generators is aligned to the nearest 3-km HRRR cell. Care is taken to ensure the correct grid cell is chosen within state boundaries and water sites. On maps, this may look like the generator has changed location slightly, as it is aligned with the center of a HRRR cell.
5. Generator types are aggregated within each 3-km cell; e.g., multiple generators of the same fuel type are summed for capacity, and capacity-weighted averages are applied to operational parameters.
6. Further spatial verification is performed to ensure the output aligns with the original data.
7. Final model input format is produced. A county-level average of all generator types was created for Phase 1 but not for Phase 2.

Table D-1 displays the generation technology types that are standard within the input generator datasets. The various biomass technologies that exist are not broken out (i.e. landfill gas, municipal solid waste, etc.) but are umbrellaed under a single “biomass” technology representation. The incorporation of geothermal heat pumps was added for this study for the Phase 1 models. It is important to note that certain technologies are combined within the model itself. This will be apparent in the model outputs and includes:

1. Natural Gas Combined Cycle and Other Natural Gas;
2. Natural Gas Combustion Turbine and Other Generation;
3. Pumped Hydro Storage (PHS) and Battery Storage. PHS will hold most of the installed storage capacity in 2020. Anything built by the model after that year would be battery storage since PHS is not often selected due to cost; and
4. Geothermal and Biomass. There is no utility-scale geothermal in the PJM footprint so this is essentially biomass.

There are certain generators that exist outside of this study’s designated PJM boundaries. These generators were brought into their nearest county within the same state. However, for spatial plotting purposes, they were left in their original location. This is most notable in Indiana. This behavior will be observed in the spatial plots of the model outputs as well.

The EIA 860 2020 early release was used to constrain the 2020 initialization period of the model to what is currently built. The latest monthly release from December 2021 was also used to constrain the capacities for the 2021 investment period as well. Both datasets were the latest available at the time of setup. This helped guide the model through historical years. The EIA October 2022 monthly release was used as a loose estimate to also help constrain the model in the 2022 investment year. However, the model was not held explicitly to the values from that report. It was used more as a back check. Discrepancies in this year are expected, as the model was allowed leeway to optimize as needed. A similar process was applied for the Phase 2 model runs using more up-to-date EIA data.

Generator assets that were retired and listed as deactivated by both PJM and MISO (considered for Illinois) were compared against the input generator datasets. Anything existing in the EIA 860 data that showed up in these retired lists was removed from the input generator datasets. This impact was small though, impacting only a unit or two.

Table D-1. The VCE input generator technology bins. Geothermal heat pumps were added for this study.

Coal	Offshore Wind	Other Generation
Natural Gas Combined Cycle	Residential Solar	Natural Gas – CCS
Natural Gas Combustion Turbine	Utility-scale Solar	Pumped Hydro Storage
Storage	Community Solar Power	Small Modular Reactors
Nuclear	Geothermal	Molten Salt
Hydroelectric	Biomass	Geothermal Heat Pumps
Onshore Wind	Other Natural Gas	

Renewable Siting Potential Dataset

VCE performs an extensive screening procedure to determine the siting potential of new generators across the contiguous U.S. This ensures that the WIS:dom-P model has constraints on where it can build new renewable generation. First, United States Geological Survey (USGS) land cover information is utilized as a base within each 3-km grid cell to determine what is there. The siting constraint information for onshore wind, offshore wind, utility-scale solar photovoltaic (PV), and distributed solar PV is displayed for a zoomed view of PJM in **Figure D-3**.

The first screening algorithm follows these steps:

1. Remove all sites that are not in appropriate land-use categories.
2. Remove all sites that have protected species at the federal level.
3. Remove all protected lands (such as national parks, forests, etc.).
4. Compute the slope, direction, and soil type to determine its applicability to VRE installations.
5. Determine the land cost multipliers based on ownership type.
6. Remove military and other government regions that are prohibited.
7. Avoid radar zones and shipping lanes.
8. Avoid migration pathways of birds and other species.

The above, along with the knowledge of what is already built within an HRRR cell from the Generator Input data, provides WIS:dom-P with a view of where it can build certain generators as well as certain technologies. It should be noted that exact location availability can always be debated.

For wind, utility-scale solar PV, distributed solar PV, and electric storage, the available space use is converted into capacity (MW & MWh) by assuming a density of the technologies. This is particularly important for wind and solar PV because of wake effects and shading effects, respectively. The maximum density of wind turbines within a model grid cell was restricted to no more than one / km^2 (< 4 MW / km^2). Solar PV was restricted to a maximum installed capacity of 33 MW / km^2. For storage, it is assumed that for a 4-hour battery the density is 250 MW / km^2. For all thermal generation, the density assumed for new build is 500 MW / km^2. Thus, for a 3-km grid cell, the resulting maximum capacities (in the contiguous U.S.) are:

1. Wind – 36 MW
2. Utility solar PV – 297 MW
3. Distributed solar PV – 68 MW
4. Storage (4-hr) – 2,250 MW or 9,000 MWh
5. Thermal generators – 4,500 MW

These densities and values also ensure that WIS:dom-P does not overbuild in a single grid cell since the combined space is constrained, as these numbers are maximums assuming only that particular technology exists.

Figure D-4 shows the state sum of the land use potential for each renewable resource across the domain. In the WIS:dom-P model, both community solar projects as well as distributed projects pull from the distributed solar potential. Onshore wind and utility-scale solar potential follow similar patterns. They are both highest in Illinois, followed by Ohio. The coastal states in the PJM domain are more limited on space for larger projects since there are higher population densities. Offshore wind potential exists for all the coastal states in PJM, though. North Carolina holds the most opportunity for offshore wind. Offshore potential is also provided to the model as an option in the Great Lakes. Distributed solar opportunities are higher in the states with higher populations. Pennsylvania, Illinois, and Ohio have the most areas for distributed solar potential.

Figure D-5 shows a zoomed in 3-km view of the renewable potential across Maryland. VCE and Exeter took an extensive look at the potential datasets for Maryland; in particular, using SmartDG[5] for comparison. SmartDG helps track county setback and zoning regulations in Maryland. Overall, VCE potential datasets were in alignment with SmartDG for wind and solar in many locations. Where they did diverge was in the minority, and for simplicity, the VCE potential datasets were adopted.

Further, the 46-mile radius around the Patuxent River Naval Air Station exclusion zone for wind development was incorporated. In particular, the eastern block of wind potential in Maryland came into question. After some investigation, it was determined that most of this potential lies outside the 46-mile circle, and there was no update performed to VCE's standard potential datasets.

[5] https://dnr.maryland.gov/pprp/Pages/SmartDG.aspx.

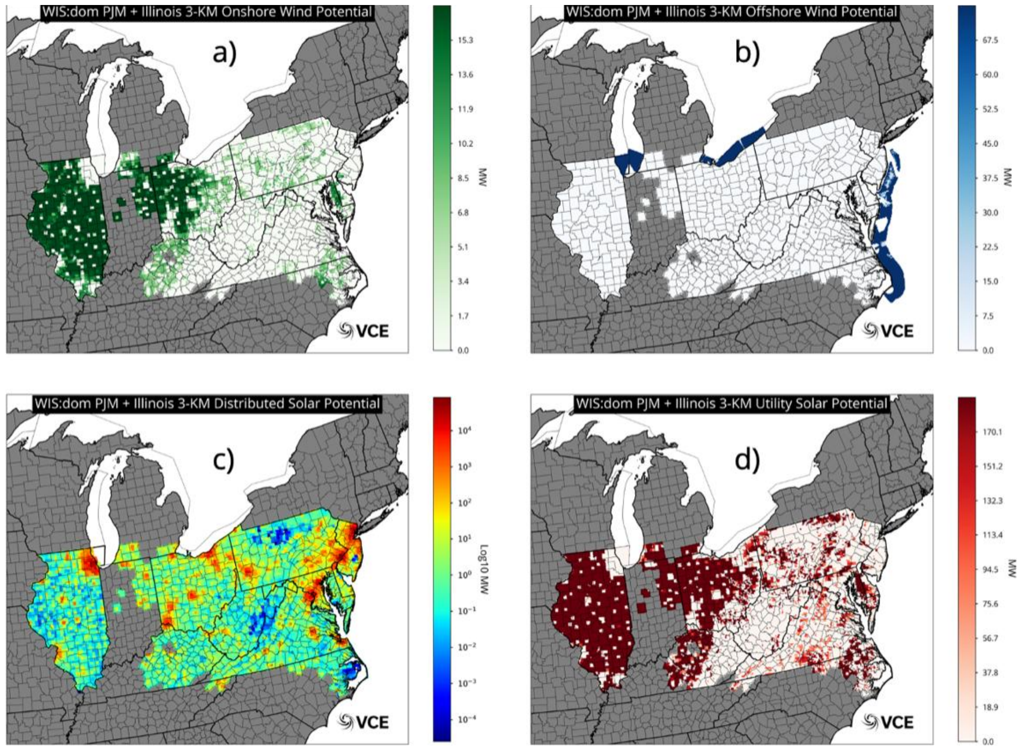

Figure D-3. WIS:dom-P a) Onshore Wind Potential; b) Offshore Wind Potential; c) Rooftop Solar Potential; and d) Utility-scale Potential in MW. The distributed solar potential is converted to a logarithmic base 10 scale due to the ranges of value for that parameter. This is a closer look at the PJM area.

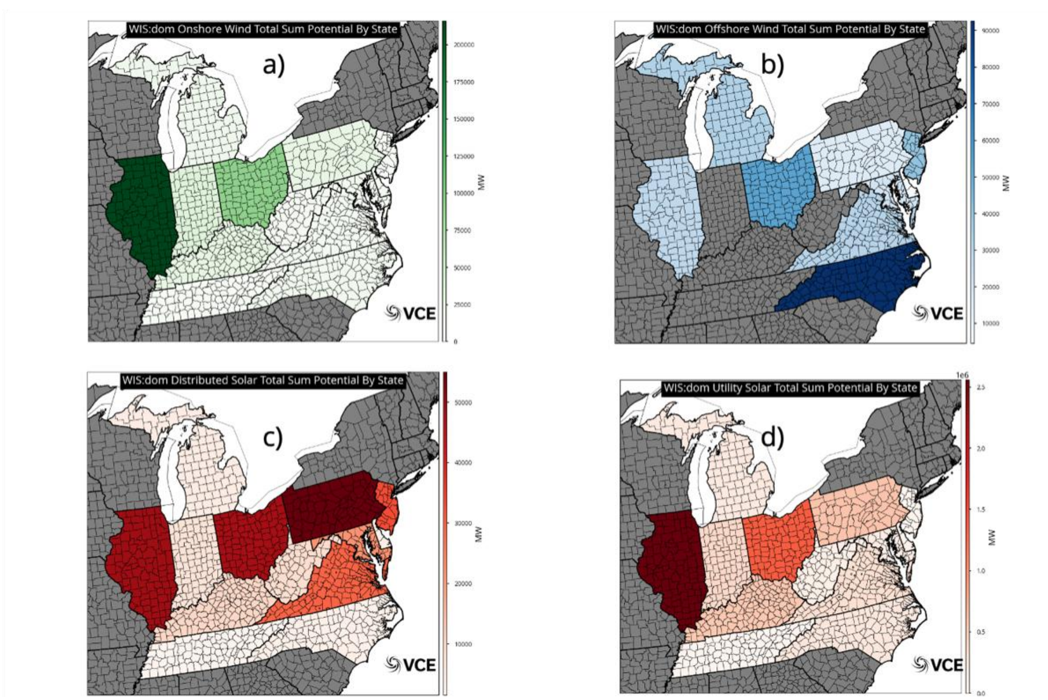

Figure D-4. WIS:dom-P Total Sum Potential by state for a) Onshore Wind; b) Offshore Wind; c) Distributed Solar; and d) Utility-scale Solar in MW.

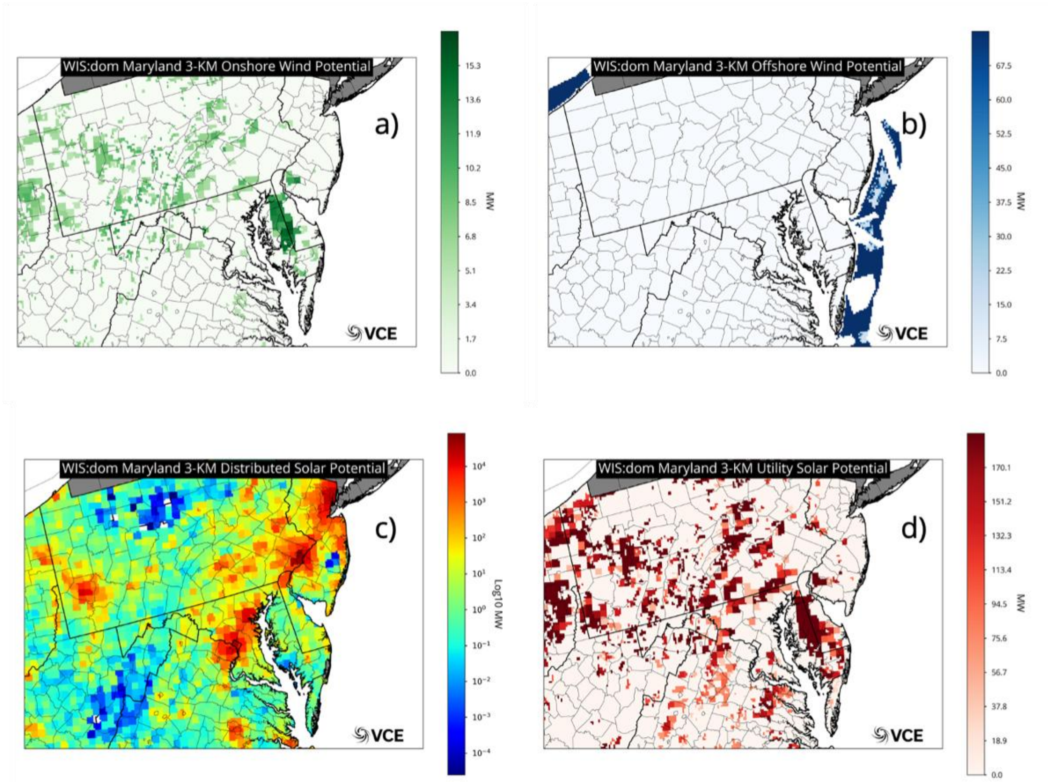

Figure D-5. WIS:dom-P a) Onshore Wind Potential; b) Offshore Wind Potential; c) Rooftop Solar Potential; and d) Utility-scale Potential in MW. The distributed solar potential is converted to a logarithmic base 10 scale due to the ranges of value for that parameter. This is a closer look at Maryland.

Standard Input Dataset

General Standard Inputs

There is a standard suite of input data for the WIS:dom-P model that sets the stage for several base assumptions about the energy grid and generator technologies. This includes:

1. Generator cost data (capital, fixed, variable, fuel);
2. Generator lifetime terms;
3. Standard new build generator heat rates;
4. Legislature in the energy sector; and
5. Jobs for various technologies.

Several of these topics, most especially the legislative pieces, are also discussed in the main body of the report.

The above list is not comprehensive and much more information is ingested by WIS:dom-P to narrow down characteristics of various generation technologies. Exeter provided input and changes to several of these model parameters. Further, custom changes brought into the model for this study were often done so through the standard inputs.

The standard inputs remain constant throughout the scenarios modeled; however, the standard inputs are changing within each scenario throughout each investment period modeled. The overnight capital, fixed O&M, and variable O&M costs for each generator technology are based upon The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) values.[6] The NREL values were chosen as they are considered reputable, are used by RTOs in their modeling, provide high granularity, and are updated frequently. The fuel costs are based on the EIA Annual Energy Outlook (AEO) data, another source that is reputable and regularly updated.[7] VCE provides fuel and capital costs multipliers by state to further tune the areal layout of these standard cost inputs. Other standard inputs are a combination of VCE internal research and work with various partners in the industry.

These input assumptions are incorporated into WIS:dom-P to provide insight and bound to optimization selections for each investment period. It offers the model a picture of what cost options are available to optimize. The NREL Moderate (Mid) ATB

[6] https://atb.nrel.gov/.
[7] https://www.eia.gov/outlooks/aeo/.

values from 2021 were used for capital, fixed and variable costs for all generation technologies.

VCE applies spatial cost multipliers to the fuel costs from the AEO. For instance, natural gas along East Coast states will be considered more expensive than in Texas and, in general, higher than the state average across the U.S. For this study, VCE updated the fuel cost multipliers for natural gas. Those changes are discussed further below.

Battery storage is often one of the most discussed inputs. Battery storage can have highly variable cost input values depending on sources. **Figure D-6** shows the cost per kW ($/kw) versus the battery pack capital cost ($/kWh) from the 2021 NREL Mid ATB costs for utility-scale storage used in the modeled scenarios.

VCE distinguishes pumped hydro storage from lithium-ion battery storage in the upfront input generator datasets. For future investment periods, typically only battery storage is selected by the model. The size and duration of the batteries are determined by the model optimization as well for each investment period. Iron-air batteries, such as those produced by Form Energy, are currently not incorporated into the WIS:dom-P options, though this technology is being monitored as many utilities are running pilot projects.[8]

WIS:dom-P utilizes generic heat rates for new-build thermal technologies. These heat rates are internally calculated to provide a general idea of thermal technology performance and are utilized for new thermal generation that is built throughout the investment periods. The heat rates for existing generation are tied to data from the EIA 860 and EIA 923 and are separate from the heat rates for new builds.

There are three advanced technologies that are included in modeling scenarios. These include natural gas CCS, SMR, and MSR. **Figure D-7** shows the standard cost data for CCS, SMR, and MSR technologies. The CCS costs are simply the costs from 2021 Mid NREL ATB values. These costs reflect a natural gas plant with CCS, not the CCS unit alone. The SMR costs for this study come from a Boise State University Study.[9] Variables costs for SMR units are rolled into fixed costs shown for this technology. The MSR cost values are created by VCE in conjunction with multiple industry partners

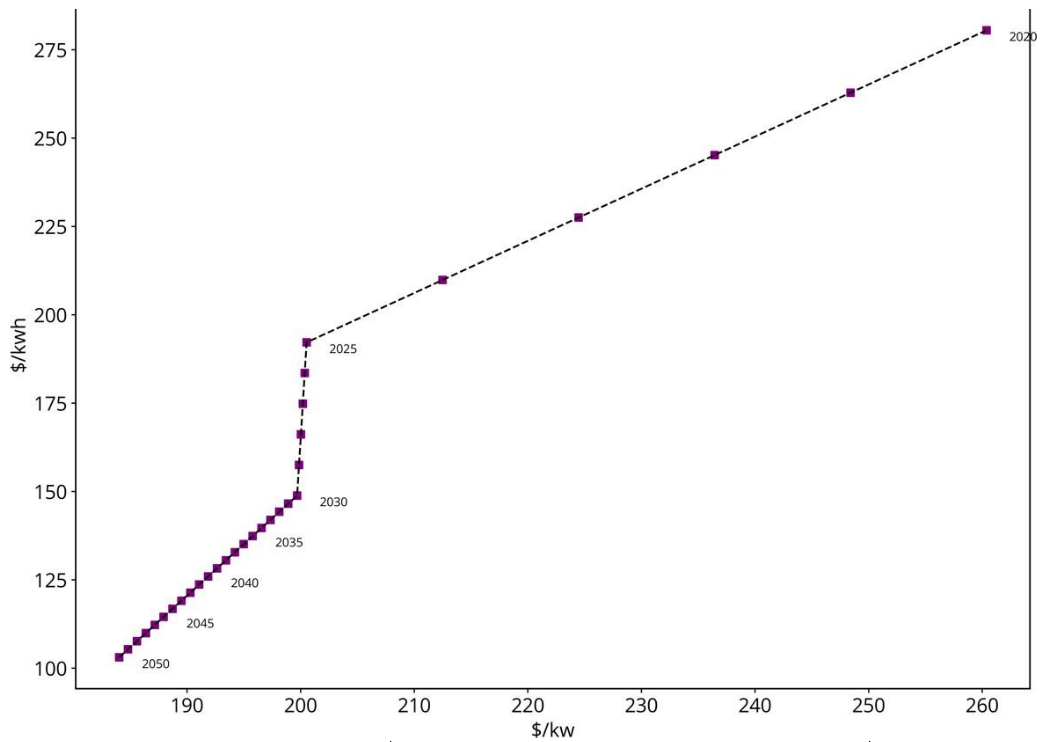

Figure D-6. The Balance of System Capital Cost ($/kW) versus the Battery Pack Capital Cost ($/kWh) at utility-scale. This is shown for the 2021 Mid NREL ATB values in purple.

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[8] https://formenergy.com/technology/battery-technology/.
[9] https://www.sciencedirect.com/science/article/abs/pii/S1364032118308372?via%3Dihub.

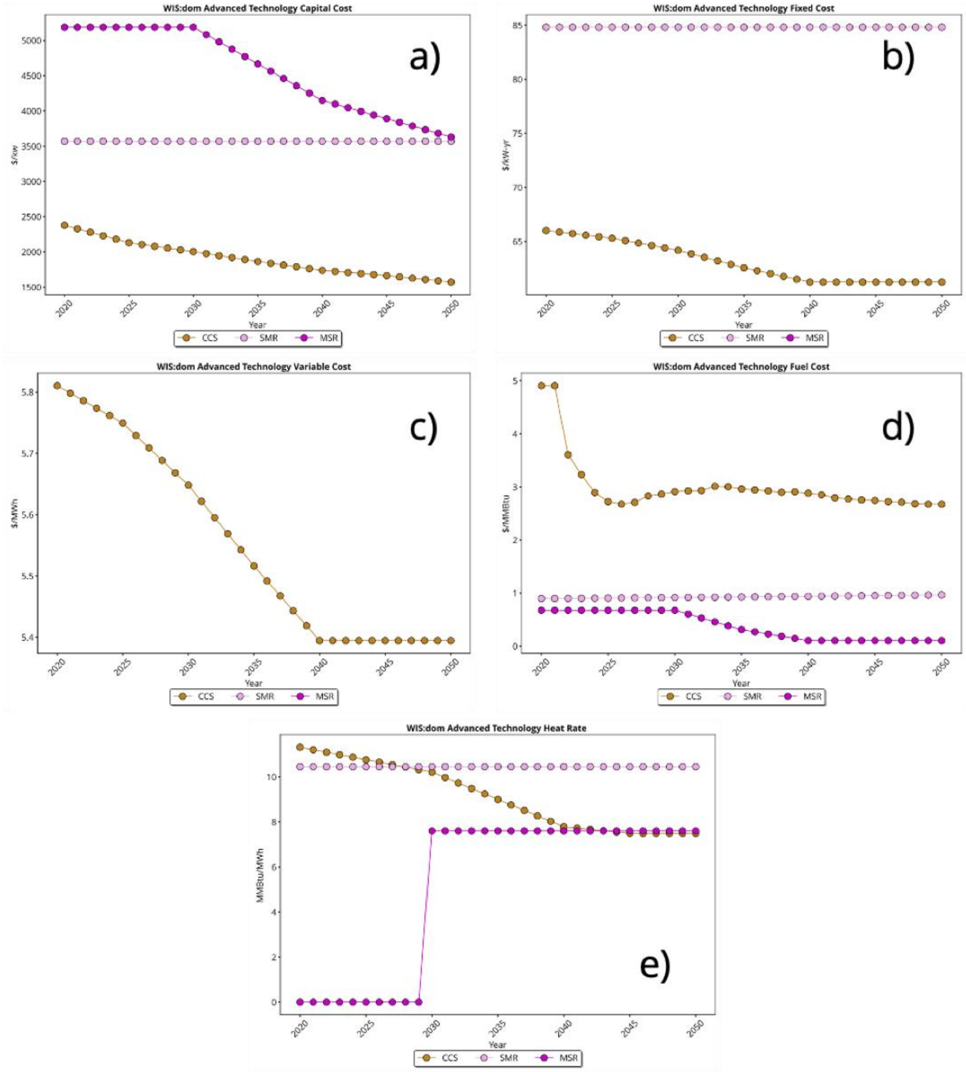

Figure D-7. The a) capital cost ($/kw), b) fixed cost ($/KW-yr), c) variable cost ($/MWh), d) fuel cost ($/MMBtu), and e) heat rate (MMBtu/MWh) for CCS, SMR, and MSR technologies in WIS:dom-P. The variable costs for SMR plants are rolled into other costs shown here.

Unless otherwise noted, the model is allowed to economically decide whether to keep existing nuclear plants in operation when an individual plant's license comes up for relicensing.

Enhanced geothermal was not included in this study as it is expensive and is rarely selected by the model. Hybrid resources (e.g., solar and storage) are also not modeled explicitly. The model does co-locate storage resources with other technologies such as solar on any given node and optimizes them with each other.

VCE uses the same real weighted average cost of capital for all generation technologies in the WIS:dom-P model. This value is 5.87%, which is applied with the book life of the technologies to provide the model with amortized capital costs. This discount rate was chosen as a good representation of utility rate structure. The lifetime of various technologies also impacts what and when the model optimally deploys generation as well as when it can retire units. **Figure D-8** shows the standard economic lifetimes by technology.

Transmission plays a large part in the WIS:dom-P model. The decision to build individual generation projects can be affected by the standard inputs around transmission aspects. Costs for greenfield alternating current (AC) and direct current (DC) lines are plotted for multiple years over various distances in **Figure D-9**. The AC costs include the cost of substations. The economic lifetime, or rather, length of amortization, of the transmission assets in the model is 60 years.

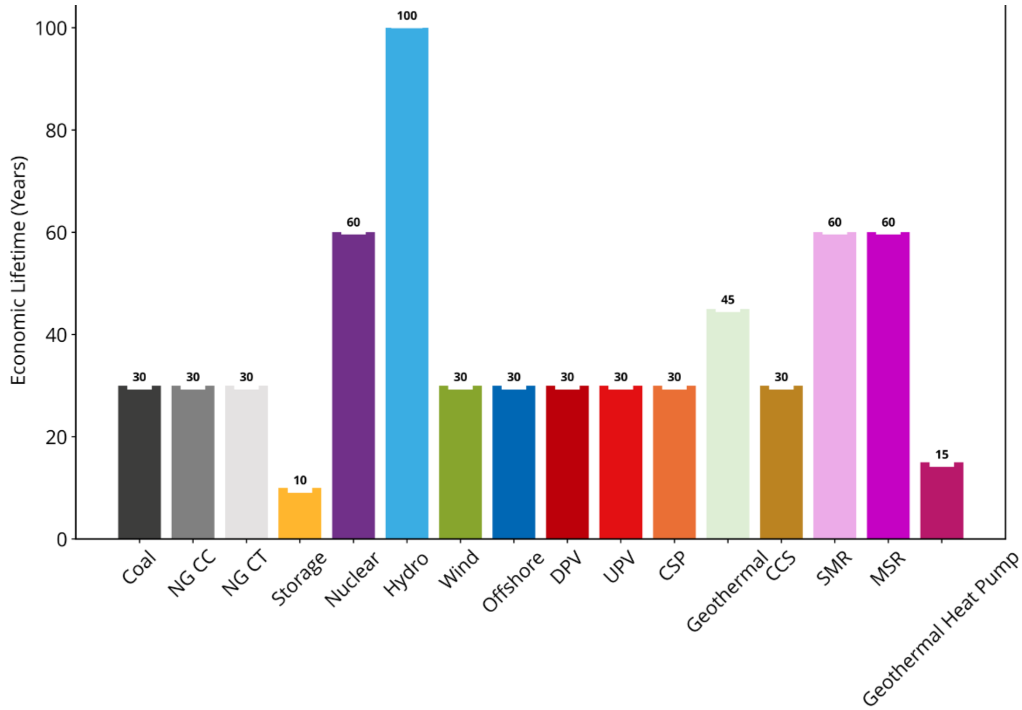

Figure D-8. The economic lifetime for each generator type within WIS:dom-P in years. The economic lifetime means the time that the debt must be cleared from the units. The SMR and MSR technologies have the same lifetime as traditional nuclear. The GHP technology lifetime is also included here.

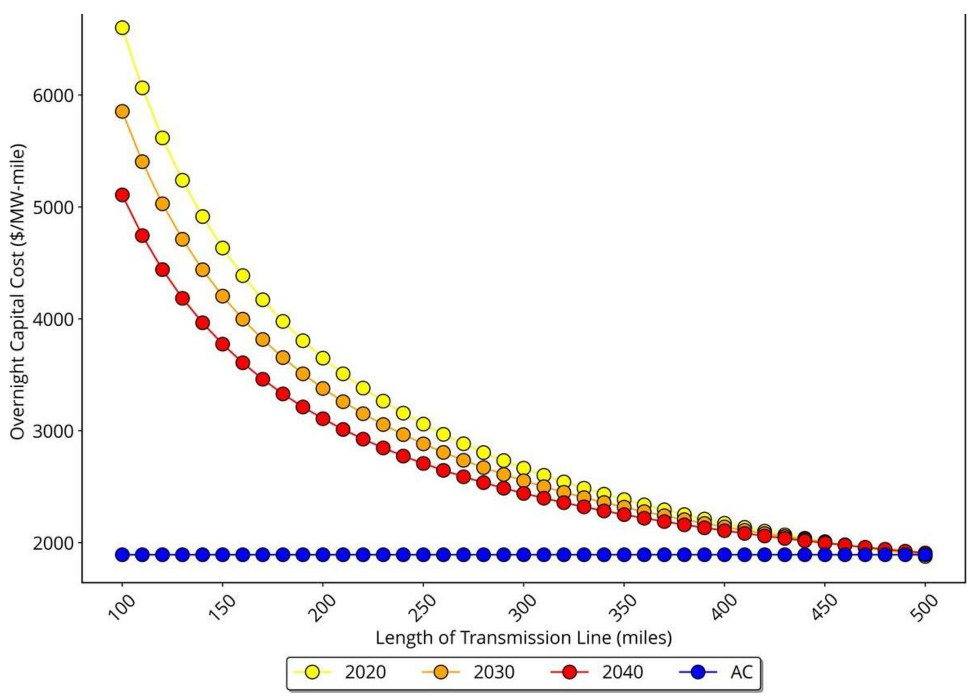

Figure D-9. The greenfield overnight capital cost of DC transmission in WIS:dom-P in real $/MW-mile installed over various distances. The overnight capital cost of AC transmission (including substations) is shown in blue. This is the same cost no matter the investment period.

RPS, Clean Energy, Offshore Wind, Energy Storage and Greenhouse Gas Goals and Requirements

VCE documents and researches the various state legislature and renewable energy goals by tracking renewable portfolio standards, clean energy mandates, offshore wind mandates, energy storage mandates, and greenhouse gas (GHG) emission reduction goals and requirements. These are utilized to inform the WIS:dom-P model of what is expected and what mandates need to be met. These provide bounds and definitions of what the model is required to build as it optimizes systems of the future. The RPS carve-outs for Maryland were modeled to a higher degree than the rest of the states in PJM as discussed in the main body of the report.

In Maryland, the general location and capacity of known offshore wind awards and projects being developed were capacity adjustments that were specifically introduced into the model. The offshore wind schedule for Maryland was set to match the construction schedule of expected offshore wind projects.

In December 2021, the Maryland Public Service Commission approved the issuance of Offshore RECs (ORECs) to US Wind and Skipjack for two offshore wind projects totaling 1,654 MW. These projects are in addition to two other offshore wind projects, also proposed by US Wind and Skipjack, representing 368 MW. The Phase 1 model runs were conducted before Orsted announced its withdrawal from contracts with the state for the two Skipjack projects. For Phase 1, all wind projects are assumed to come online by 2027. This includes US Wind Phase 1 (248 MW), Skipjack Phase 1 (120 MW), Momentum Wind (808 MW), and Skipjack Phase 2 (846 MW) totaling 2,022 MW. The interconnections are also assumed to come into Sussex County, Delaware and the capacities are assigned to the nearest Maryland county (Worcester County). For Phase 2, it was assumed that the goals of the POWER Act of 2023 would be met, namely that 8.5 GW of offshore wind would be in operation by 2031. Exeter and VCE assumed a constant rate of capacity addition from 2027 to 2031 to reach the 8.5 GW target.

For Phase 1, it was decided to recognize any GHG legislation within PJM as goals and not as a binding constraint unless specifically called out in certain model scenarios. The CSNA targets were assumed to be binding for Phase 2. The CARES Act carve-outs for Maryland were modeled to a higher degree than the rest of the states in PJM. That is discussed further in the main body of the report, although some assumptions are also explained below. The 3-GW energy storage goal in Maryland was not incorporated for the Phase 1 model runs but was incorporated for Phase 2.

Clean and Renewable Energy Standard

Natural gas with CCS and biomass with CCS are assumed to capture 100% of the CO_2 emitted during use. In the model, we assume these units only reach a 95% capture efficiency per various research and literature. It was assumed that this meets the necessary standards to qualify for a clean energy standard such as CARES.

The combined heat and power (CHP) systems modeled were only able to have an efficiency rating between 65-75%. This decision came from seeing dramatically increased costs for more efficient CHP systems. This means that CHP is only able to capture 50% of the CARES credit. See the main report for additional information about the CES assumptions applied to Phase 1 and Phase 2.

Inflation Reduction Act

There are several updates incorporated into the model from the Inflation Reduction Act (IRA). This includes:

1. The Investment Tax Credit (ITC) (Section 48) extension as well as the Clean Energy ITC (CEITC) (Section 48D) that takes over in 2025. The CEITC is technology agnostic and applies to battery storage, onshore wind, offshore wind, utility-scale solar, biomass, geothermal, advanced nuclear, hydrogen storage, pumped-hydro storage, thermal energy, linear generators, hydrogen fuel cells, and hydrogen electrolyzers in the WIS:dom-P model. Incentive rates incorporated into WIS:dom-P reflect the added domestic content requirement bonus. A safe harbor is applied to the incentive (typically 4-5 years depending on IRS instruction). The safe harbor is extended up to 10 years for projects that are offshore or built on federal lands.
2. The Production Tax Credit (PTC) (Section 45) extension as well as the Clean Energy PTC (CEPTC) (Section 45Y) that takes over in 2025. The CEPTC is technology agnostic and applies to onshore wind, offshore wind, utility-scale solar, biomass, geothermal, advanced nuclear, and linear generators in the WIS:dom-P model. Incentive rates incorporated into WIS:dom-P reflect the added domestic content requirement bonus. A safe harbor is applied to the incentive (typically 4-5 years depending on IRS instruction). The safe harbor is extended up to 10 years for projects that are offshore or built on federal lands.
3. A residential ITC (Section 25D) for distributed solar technologies, geothermal heat pumps, small wind systems and fuel cells.
4. A PTC for existing nuclear facilities. There is no safe harbor or domestic content requirement bonus.
5. A PTC for the production of hydrogen (Section 45V). There is no safe harbor or domestic content

requirement bonus. We do assume the emission requirements are met for production. The model only allows clean hydrogen anyway. A facility can choose between this or the manufacturing ITC for hydrogen.

6. A manufacturing ITC (Section 45X) for building facilities with advanced fuels including hydrogen, capped at $10 billion. An H2 production facility can choose between this or the PTC for hydrogen.
7. Extension of Section 45Q for new CCS assets. There is no safe harbor or domestic content requirement bonus.
8. A new Section 45Q incentive for direct air capture (DAC) assets. There is no safe harbor or domestic content requirement bonus.
9. For simplification, it is assumed that domestic manufacturing can ramp fast enough to receive the domestic content added bonus.
10. There are also disadvantaged communities' incentives for solar and additional incentive for units built in "energy communities". This setup for increased ITC and PTC bonuses was not available in time to incorporate into the model for this project.

The various PTC options available to the model for clean technologies are shown in **Figure D-10**. The hydrogen PTC is plotted in **Figure D-11**. The various ITC options available to the model for clean technologies are shown in **Figure D-12.**

After 2025, the model allows for optionality where qualifying technologies can choose either the ITC or PTC. In general, for wind and solar, the model tends to choose the PTC when the weather resource is good. The model may choose the ITC where the weather resource is more marginal and capital costs are high for certain renewable energy technologies.

The 45Q options available to carbon capture systems and direct air capture units in the model are shown in **Figure D-13**.

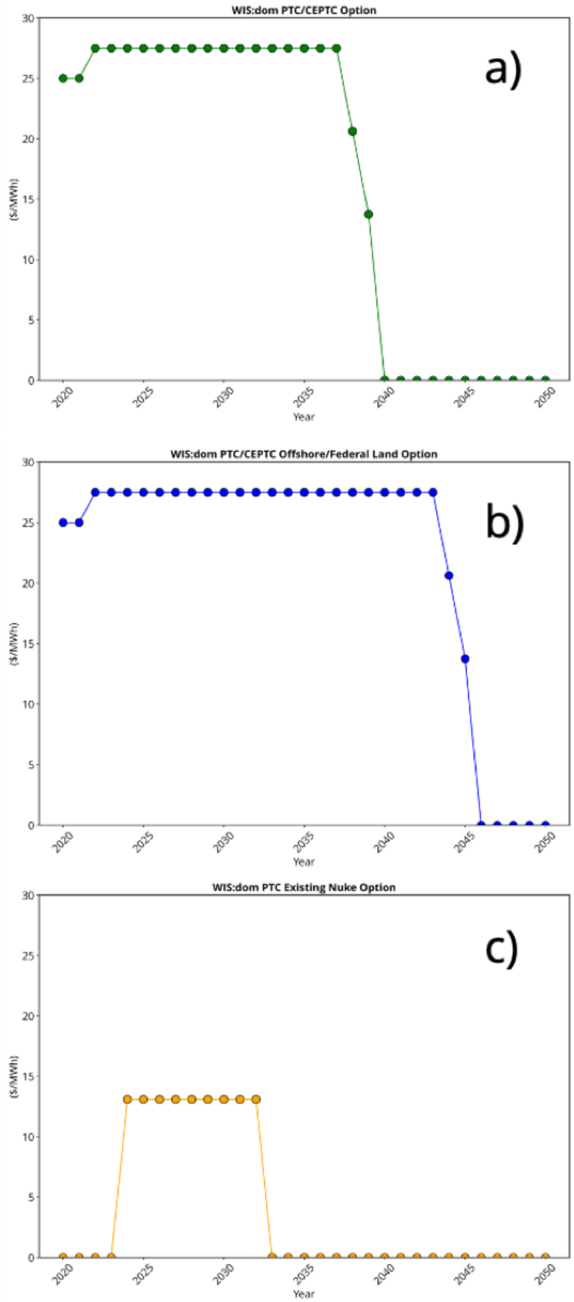

Figure D-10. The a) PTC/CEPTC as applied to clean technologies built across the United States; b) PTC/CEPTC as applied to clean technologies built either offshore or on federal land; and c) a PTC for existing nuclear facilities. All units are in $/MWh. Before 2025, only the PTC is available, and that is not technology agnostic.

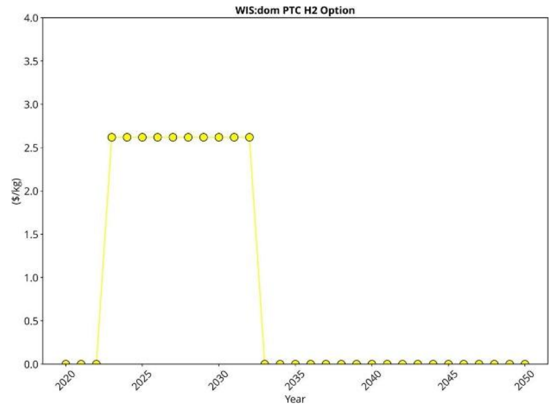

Figure D-11. The PTC for the production of hydrogen in $/kg in 2020 real dollars.

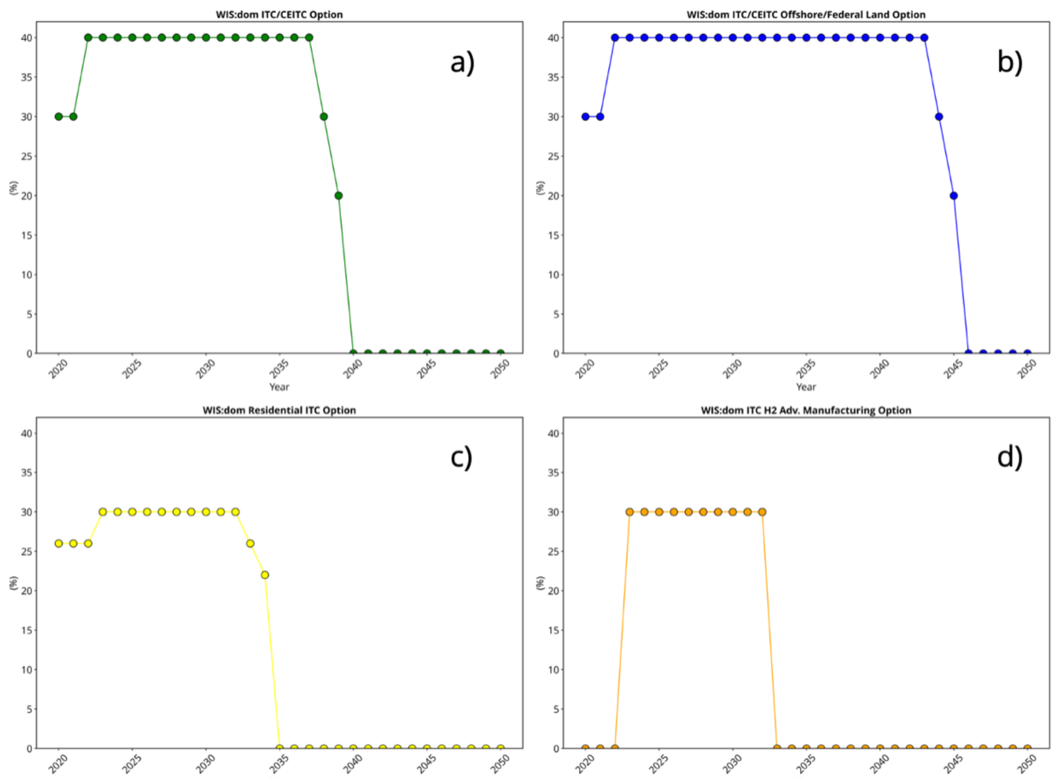

Figure D-12. The a) ITC/CEITC as applied to clean technologies built across the United States; b) ITC/CEITC as applied to clean technologies built either offshore or on federal land; c) a residential ITC; and d) an ITC for the development of advanced manufacturing facilities. All units are in %. Before 2025, only the ITC is available, and that is not technology agnostic.

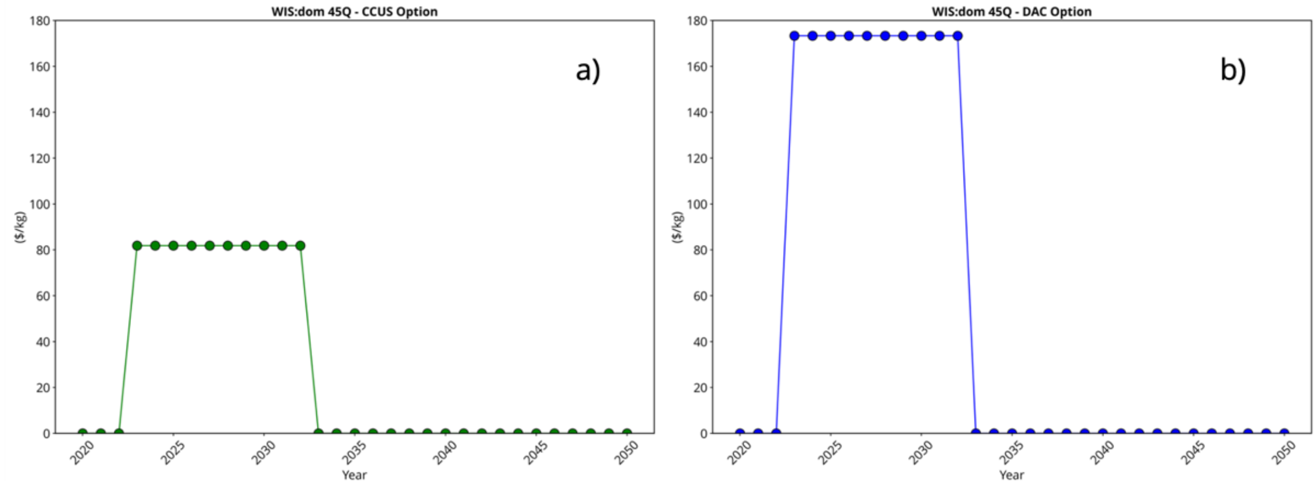

Figure D-13. The a) 45Q extended for carbon capture systems; and b) the new 45Q for direct air capture systems. All units are in $/kg in 2020 real dollars.

Illinois Climate and Equitable Jobs Act

Illinois was the largest source of renewable energy credits for Maryland RPS compliance in 2022 (28.5%) and is expected to continue to be a large source for the Maryland RPS in the future.[10] In September 2021, Illinois's Climate and Equitable Jobs Act (CEJA) was passed.[11] With all of the changes coming in from CEJA, the entire State of Illinois was modeled for the Phase 1 model runs, including the portions outside of PJM. This avoids a non-optimal build-out of variable renewable sources in ComEd by including resources in other parts of Illinois.

Notable changes from the CEJA legislation:

1. Illinois RPS increased to 40% by 2030 and 50% by 2040. This was incorporated into the model.
2. Illinois state policy to transition to 100% clean energy by 2050, but the study is not considering this a binding constraint, especially since the target year is well beyond the 2040 final investment period.
3. The Braidwood, Byron, and Dresden nuclear power plants are assumed not to retire while receiving financial support.
4. Annual energy efficiency targets and associated deemed savings were incorporated into the model through updates to the annual loads of Illinois.
5. Several fossil fuel plant provisions, which either retire or reduce emissions by certain dates dependent on ownership, level of air emissions, and location to environmental justice (EJ) communities. Plant exemptions from these deadlines are available if an RTO proclaims the plant is essential to maintain reliability. No exemptions were provided at this point to the model as none were known at the time of running the model. Since coal is typically retired relatively quickly in the model, those technologies were left in Illinois to retire economically. The provisions of this law will affect the retirement dates of natural gas in particular in the VCE model.

Several stipulations came out of CEJA regarding fossil fuel emission reductions:

1. All privately owned/investor-owned utility coal/oil plants must become zero emissions by January 1, 2030 or retire. Coal/oil plants owned by public utilities have until January 1, 2035.
2. All natural gas plants must be zero emissions or convert to green hydrogen by January 1, 2045. Some of these plants may have to have to meet these requirements earlier than 2045, depending on proximity to EJ communities and rate of emissions.
3. Non-public gas plants:
   (a) Reach zero emissions or retire or adopt 100% green hydrogen by:
      i. 1/1/2030, if (NOx emissions >0.12 lbs/MWh or SO_2 emissions >0.006 lbs/MWh) and (located within 3 miles of an EJ community or equity investment eligible community); or
      ii. 1/1/2035, if (operating prior to September 2021) and (NOx emissions ≤ 0.12 lbs/MWh) and (SO_2 emissions ≤ 0.006 lbs/MWh) and (located within 3 miles of an EJ community or equity investment eligible community).
      iii. Reduce existing CO_2 emissions by 50% by 1/1/2030; or 1/1/2040, if:

[10] Public Service Commission of Maryland, Renewable Energy Standard Portfolio Standard Report with Data for Calendar Year 2022, November 2023, https://www.psc.state.md.us/wp-content/uploads/CY22-RPS-Annual-Report_Final-w-Corrected-Appdx-A.pdf.
[11] https://www2.illinois.gov/epa/topics/ceja/Pages/default.aspx.

A. (NO_x emissions >0.12 lbs/MWh or SO_2 emissions >0.006 lbs/MWh) and not (located within 3 miles of an EJ community OR equity investment eligible community);
B. Reduce existing CO_2 emissions by 50% by 1/1/2035 and limit operations to ≤6 hours per day on average each calendar year except in ISO/RTO designated emergency conditions (when up to 25 consecutive hours is allowed); and
C. Not already in compliance or retired and heat rate ≥7,000 Btu/kWh.

4. By January 1, 2045, all remaining large electric generating plants must reach zero emissions or retire or adopt 100% green hydrogen, including cogeneration and CHP.

The Illinois natural gas fleet was analyzed against the provisions above. The spatial requirements were investigated using shapefiles for EJ communities[12] and Restore, Reinvest and Renew (R3) areas.[13,14] In both cases, a 3-mile buffer was added to these shapes per legislative direction. If a natural gas plant was in these shapefiles, a flag was raised.

VCE processed the eGrid CEMS 2019 NOx and SO_2 rates[15] to determine the emissions information at a plant level. If there were no emission rates to match to the EIA 860 plant data, the emission rates were determined using that plant's heat rate alongside standard emission content values VCE calculates internally for the various pollutants. A final list of natural gas plants that are expected to retire or reduce emissions by certain investment periods was the final product of this analysis. These changes affected specific investment years going forward and were brought in as capacity adjustments (retirements). Conversion or retrofit to hydrogen plants was not modeled since that level of detail would have required increased model run times for items that were not the main area of focus for this study. This specifically affected natural gas technology types in Illinois since coal is set to economically retire. The natural gas plants are allowed to retire early if it is economic for the model to do so.

Infrastructure Bill

The Infrastructure Bill passed through Congress and was signed into law in November 2021.[16] The Infrastructure Bill allocates $6 billion to prevent existing nuclear power plants from retiring if they are certified as safe. The nuclear power support in the bill was represented in the model by allowing no nuclear to retire before 2027. The passing of this bill, but also CEJA in Illinois itself, allowed for the continued operation of the Dresden, Bryon, and Braidwood nuclear plants. These were originally slated for retirement and would have come out of the model because PJM had listed them for future deactivation.

Regional Greenhouse Gas Initiative

RGGI[17] is a regional collaborative among 12 states in the Northeast aimed at reducing the amount of CO_2 pollution from power plants via the issuance of a capped number of tradable CO_2 allowances. States in RGGI institute a cap on CO_2 emissions that declines over time and hold quarterly auctions to distribute CO_2 allowances. Fossil-fueled plants over 25 MW in RGGI states are required to have allowances equal to their CO_2 emissions over a three-year period.

The following states in PJM are a part of RGGI for the Phase 1 model run:

- Delaware
- Maryland
- New Jersey
- Pennsylvania
- Virginia

For Phase 2, Pennsylvania was excluded from this list. There are additional states in RGGI, but since this study only looked at PJM, the states listed above are the ones affected. The caps were adjusted to only include the PJM states for this study. Further, the caps were set to be the adjusted values provided by the RGGI allowance guidance. The model will treat the overall RGGI cap as binding as applied to all of PJM. Carbon dioxide is considered a "global" emission in WIS:dom-P. Thus, this constraint is not applied on a state-by-state basis. The total CO_2 emissions reduction by 2040 for PJM is 100,334,474 metric tonnes.

EmPOWER Maryland

In 2008, the Maryland General Assembly enacted the EmPOWER Maryland (EmPOWER MD) Energy Efficiency Act of 2008 that set a goal to decrease per capita electricity usage and peak demand 15% by 2015. In 2017, the General Assembly enacted legislation that established an annual energy savings goal of 2% of gross energy sales for the 2018-2020 and 2021-2023 program cycles. At the time of the Phase 1 model run, significant changes to EmPOWER MD were expected to incorporate the Climate Solutions Now Act

[12] https://www.illinoissfa.com/environmental-justice-communities/.
[13] https://r3.illinois.gov/eligibility.
[14] https://www.census.gov/cgi-bin/geo/shapefiles/index.php.
[15] https://www.epa.gov/egrid/download-data.
[16] https://www.congress.gov/bill/117th-congress/house-bill/3684/text.
[17] https://www.rggi.org/.

enacted in 2022 by the General Assembly.[18] Because of that uncertainty, EmPOWER MD is assumed to expire in 2023 for the Phase 1 model run but was incorporated into the Phase 2 model run.

Additional Custom Cost and Capacity Inclusions

This subsection will overview custom additions and changes for the WIS:dom-P model. In addition to the legislative inclusions discussed above, these were changes specifically performed for the Exeter model runs.

Natural Gas Carbon Capture Systems

By default, the WIS:dom-P model can choose to build a new natural gas plant or it can build a new natural gas plant with a CCS unit. Added for this study, WIS:dom-P can also retrofit an existing natural gas plant with a CCS unit. Cost economics for this were sourced from the National Energy Technology Laboratory, which is also the same source of information that the NREL ATB uses for CCS.[19] The model assumes that all natural gas CCS units can reach an efficiency of 95% which satisfies the CARES Act where applicable.

Table D-2 shows the CCS cost options as viewed by the model. If a natural gas unit is retrofitted with a CCS unit in the model, that unit's heat rate is increased by 12% to account for the loss in fuel conversion efficiency that comes with CCS applications.

	New Natural Gas Unit	Natural Gas CCS Retrofit Alone	New NG with CCS
Capital Cost ($/kw)	970	1407	2378
Fixed Cost ($/kw-yr)	28	38	66
Variable Cost ($/MWh)	2	4	6
Heat Rate (MMBtu/MWh)	6.36	N/A	7.64

Table D-2. The 2020 capital cost, fixed cost, variable cost, and heat rate for a natural gas retrofit CCS unit in comparison to other natural gas CCS options in the WIS:dom-P model. The heat rate is N/A for retrofits, as that will be determined in the model. We do not assume any improvement in costs going forward in time.

Biomass Carbon Capture System Costs

By default, the model can build a new biomass generator. WIS:dom-P does not distinguish between biomass types such as landfill gas, municipal solid waste, etc. For this study, VCE added the capability for the model to select to add a CCS unit to either an existing or new build biomass unit. These systems are expensive and it is expected it will most likely be utilized in a limited fashion, if at all. **Table D-3** shows the costs provided. The costs of a new biomass plant with a CCS system was provided from a Michigan Institute of Technology (MIT) study.[20] The cost of a new biomass plant came from NREL ATB. The cost of the retrofit is the difference between these two options.

	New Biomass Unit	Biomass CCS Retrofit Alone	New Biomass with CCS (BECCS)
Capital Cost ($/kw)	4557	5108	9665
Fixed Cost ($/kw-yr)	119	65	184
Variable Cost ($/MWh)	5.9	3.6	9.5

Table D-3. The 2020 capital cost, fixed cost, and variable cost for a biomass retrofit CCS unit in comparison to other biomass CCS options in the WIS:dom-P model. We do not assume any improvement in costs going forward in time.

The biomass retrofit is eligible for the Maryland RPS. This technology can also receive double credit from CARES when that is utilized within scenarios.

Combined Heat and Power System Costs

There currently are CHP units installed across the U.S. and in the PJM footprint and are represented in WIS:dom-P in the natural gas technology generator input buckets at the utility level. Cost information for CHP technologies is shown in **Table D-4**.[21] CHP is also eligible for CARES, with credits awarded based on plant efficiencies. Specifically, to receive full credit, a CHP plant must have plant efficiencies of 90% or more. CHP plants between 75-90% efficient would receive ¾ credit, while CHP plants between 60-75% efficient would receive ½ credit.

Although higher efficiency CHP plants receive more credit, the higher efficiencies come at a much higher cost. The more expensive, higher efficiency versions of this technology are so expensive that the model is expected to rarely, if ever, select it, even if eligible for CARES. The reciprocating engine is currently the most installed unit by quantity across the country. The gas turbine CHP is currently the most installed unit by capacity across the country. VCE created a representative cost value for both technologies. An average of gas turbines and reciprocating engines were modeled as CHP units, even though they will not be eligible for a full clean energy resource credit. The efficiency modeled will receive ½ credit.

[18] In 2024, the Maryland General Assembly enacted House Bill (HB) 864 which made several changes to EmPOWER MD. Enactment of HB 864 occurred after completion of the Phase 1 and Phase 2 model runs and was therefore not incorporated.
[19] https://www.netl.doe.gov/energy-analysis/details?id=2950.
[20] https://www.sciencedirect.com/science/article/abs/pii/S0959378021000418.
[21] https://www.energy.gov/sites/prod/files/2016/09/f33/CHP-Recip%20Engines.pdf.

	Gas Turbine	Reciprocating Engine	Gas/Reciprocating Average	Fuel Cell
Capital Cost ($/kw)	2323	2301	2312	6193
Fixed Cost ($/kw-yr)	54	15	35	N/A
Variable Cost ($/MWh)	8	10	9	42
Terms (years)	25	25	25	25
Heat Rate (MMBtu/MWh)	4.81	4.4	4.61	4.98
Sources: CEJA, MEA, Mondre				

Table D-4. The 2020 capital cost, fixed cost, variable cost, lifetime, and heat rate for a representative CHP technology in the WIS:dom-P model. The average cost of the gas turbine and reciprocating engine was used for the model. The fuel cell costs are shown for comparison to display the range of costs that can occur with CHP technologies. We do not assume any improvement in costs going forward in time.

Geothermal Heat Pump Costs

WIS:dom-P allows GHP to replace air-source heat pumps and air-conditioning (A/C) units in a dwelling in the Phase 1 models. GHP has a carve-out in the Maryland RPS starting at 0.05% in 2023 and increasing to 1% in 2028. VCE incorporated the current installed capacity of GHP for Maryland using data from PJM-GATS, as discussed above. VCE's model optimizes the size of the GHP systems that are needed to meet the carve-out. GHP also reduces the load on the grid due to its higher efficiency as compared to the combination of A/C and resistance heating.

The costs for GHP systems are assumed to be $2,500/kW with a lifetime of 15 years and a coefficient of performance (COP) value of 4.0.[22] The cost and lifetime came from a mix of sources such as the New York State Energy Research and Development Authority (NYSERDA), data collected and provided by MEA, and data compiled by Mondre Energy Inc. The capital costs remain consistent, with no forecasted improvement over the duration of the investment periods modeled. The fixed costs of the geothermal heat pumps were assumed to be similar to standard A/C and heating units and as such, were not incorporated.

The COP of standard heating units was assumed to be 2.5 (an average from Energy Star 8.5 Energy Efficiency Rating, or EER). In terms of managing peak load, VCE's model will account for changes to the load profile from GHP.

Since GHP systems use less load than standard heating and cooling units, their addition is actually a load reduction to the system overall. WIS:dom-P is still required to maintain planning reserve margins and load-following reserves. GHP systems are required to meet Maryland RPS build-out mandates. The model is also not allowed to build more than 10,000 units per year, representing the limits of manufacturing, to ensure that any build-out remains reasonable. Build-out is also limited to no more than 60 MW per year.

Emissions Control Costs

Emissions control capabilities, in addition to the carbon capture system options mentioned above, were also explored. Analysis was performed to determine the cost-effectiveness of these systems outside of WIS:dom-P model runs. It was found that the cost was high enough that WIS:dom-P might only sparsely choose this as an option. Incorporating this option would add to model solve times and it was decided not to incorporate it as a feature.

PJM Construction Queues and Future Deactivations

For Phase 1, projects under construction in PJM's interconnection queue were brought into the model at the county level if located in Maryland and at the state level if located outside of Maryland.[23] For Phase 2, projects brought into the model were only at the state level. Units were brought into the model based on their projected operational date. The data from the PJM interconnection queue was pulled in December 2021 and incorporated into the model.

The future PJM unit retirement list was also incorporated from December 2021.[24] This will force the model to retire these units by the deactivation dates provided. Most of these retirements affect only the early years of the modeling run.

Illinois CEJA Natural Gas Capacity Impacts

As discussed above, the Illinois CEJA requires certain thermal units that meet defined criteria to retire. **Figure D-14** shows the impacts of the Illinois CEJA on natural gas plants over 25 MW and how those impacts were represented in the WIS:dom-P model. Most of the natural gas in the state is impacted by 2045, although

[22] https://www.energystar.gov/products/geothermal_heat_pumps/key_product_criteria.
[23] https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.
[24] https://www.pjm.com/planning/services-requests/gen-deactivations.

a substantial amount of capacity is expected to go offline by 2040.

Coal and Natural Gas Fuel Cost Hourly Multipliers

VCE incorporates intra-annual variability cost multipliers for coal and natural gas. This reflects the change in the price of coal within a given year. This was performed to help balance the dispatch of coal and natural gas to match trends observed in PJM. Incorporating this data will drive fuel switching between natural gas and coal that regularly occurs in power markets and marginal pricing.

The coal intra-annual multipliers were updated to be PJM-specific, pulling quarterly shipment fuel cost information from Central and Northern Appalachia to the electric power sector for coal from EIA.[25] Natural gas electric power prices are available monthly and were pulled for PJM states for this study.[26]

Figure D-15 shows the interplay between the coal and natural gas fuel cost multipliers over one year. This is a multiplier that is applied to the fuel cost values input into the model from the EIA AEO. A multiplier over 1 means that costs are higher than the standard fuel cost value given for that hour in the model. Coal prices are slightly higher than natural gas prices for the summer months. The reverse is true for the winter months.

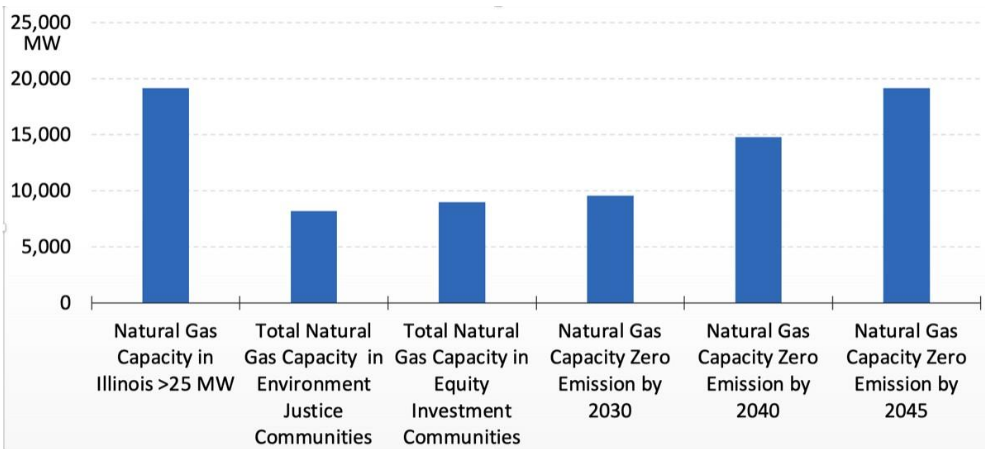

Figure D-14. Illinois natural gas impacts from CEJA.

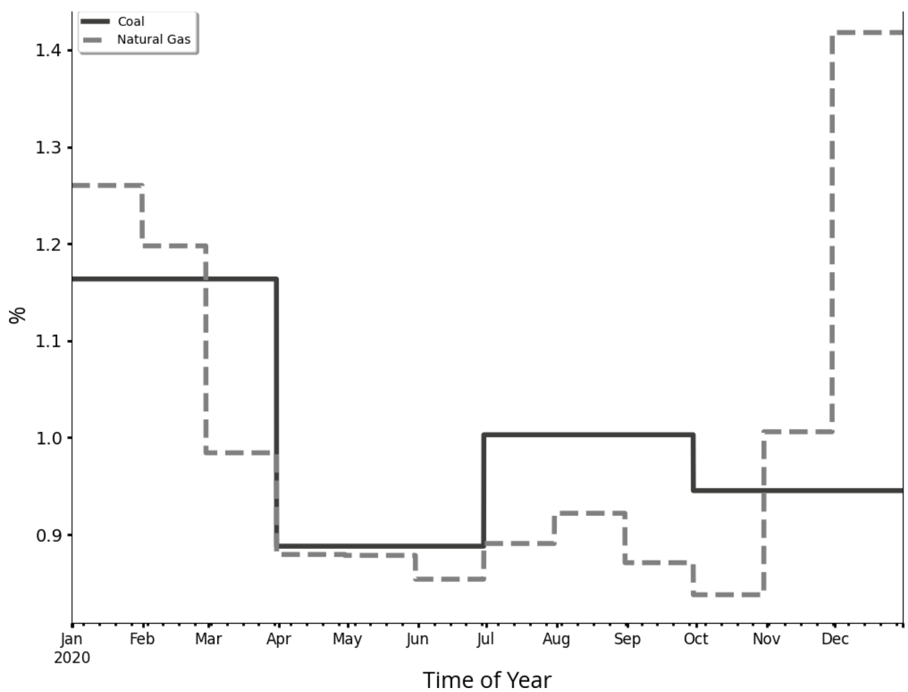

Figure D-15. Annual profile of coal and natural gas fuel cost multipliers (%).

[25] https://www.eia.gov/coal/data/browser/.
[26] https://www.eia.gov/dnav/ng/NG_SUM_LSUM_A_EPG0_PEU_DMCF_M.htm.

Hydroelectric Dispatch Profiles

The hourly hydroelectric (or hydro) profiles are used in the model to signify the general dispatch of hydro units at the state level. The hydro dispatch is tied to the weather year used in the model but also represents to the model any curtailments to hydro production that may be required (i.e., curtailments related to seasonal salmon closures in the Pacific Northwest). Conservatively, VCE limits hydro production to historical dispatch curves from the EIA AEO and does not allow for more than that to occur by volume.[27] This was done to ensure that hydro is not relied upon during periods of stress in the future when water availability is unknown. For this study, diurnally driven dispatch was allowed for hydro in PJM. The diurnal demand shape was reflected in the dispatch, allowing the model to follow demand more if selected to do so. It is important to note that the volume of water allowed to be dispatched does not change with this update. The shape of when a hydroelectric facility can choose to dispatch has changed. **Figure D-16** shows the average hydroelectric profile shape for PJM. The same is shown in **Figure D-17** for Maryland alone.

Natural Gas Fuel Cost Multipliers

VCE updated the natural gas fuel cost multiplier in WIS:dom-P that is applied to fuel costs from the EIA AEO. This update takes into account citygate prices and electric power prices (when available) from commercial, residential, and industrial sectors over the last 10 years. These prices are converted to a multiplier value across states. **Figure D-18** plots the spatial variations of fuel costs for thermal units with the updated natural gas multipliers.

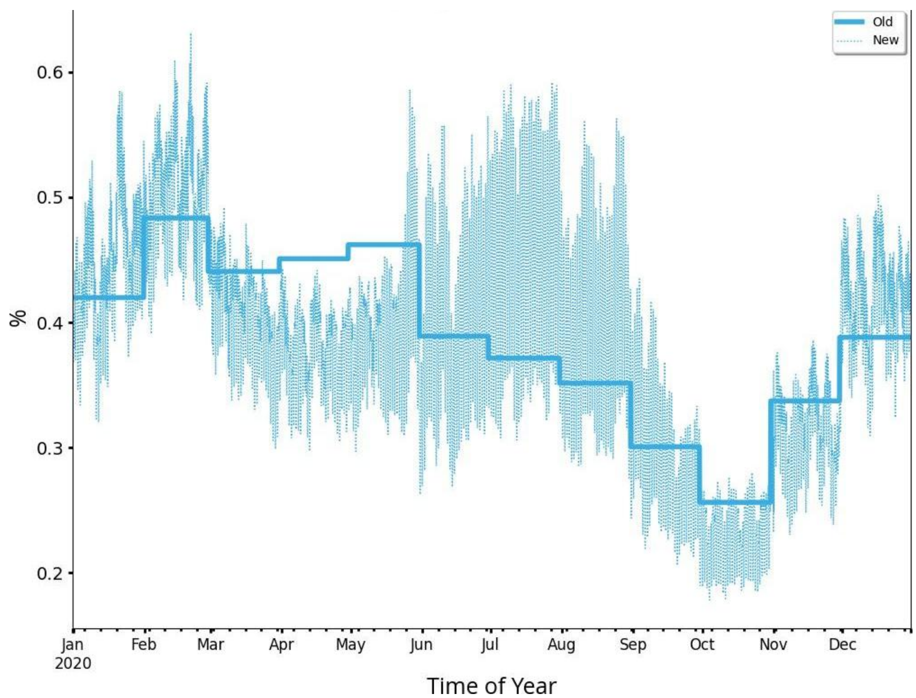

Figure D-16. Average hydroelectric profiles for PJM and Illinois (%) in 2020.

[27] https://www.eia.gov/electricity/data/state/generation_monthly.xlsx.

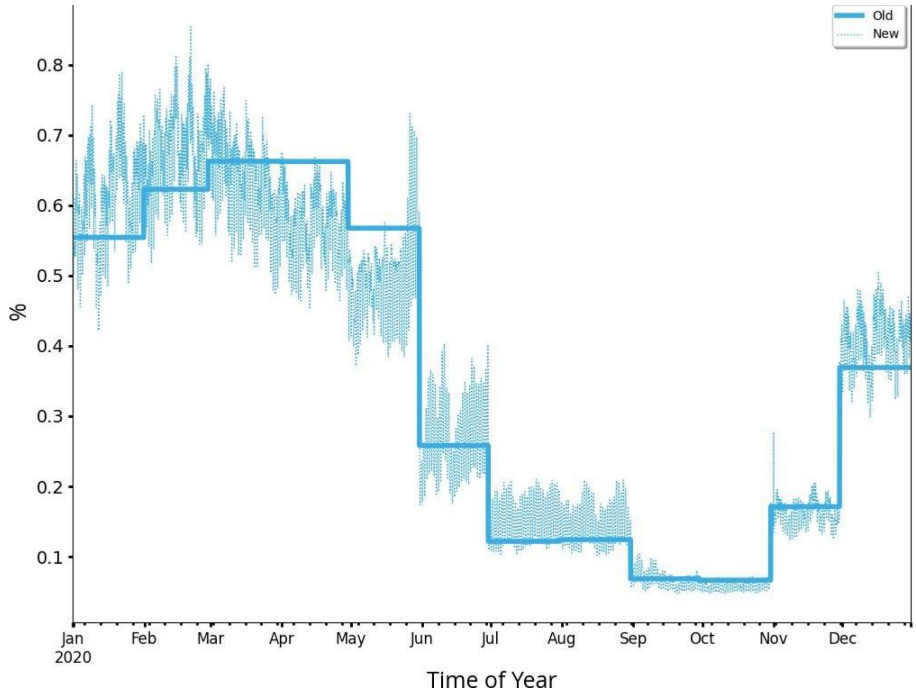

Figure D-17. Average Hydroelectric profiles for Maryland in 2020.

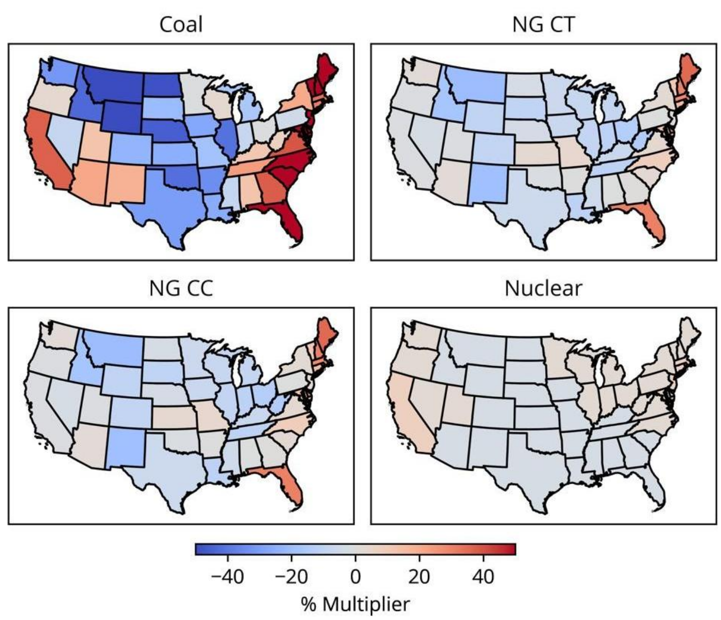

Figure D-18. The WIS:dom-P fuel cost multiplier is shown by state for each technology across the U.S. The color scale shows a percentage multiplier applied to standard fuel costs. Shades of red show where the fuel cost is scaled higher by a given percentage. Cool shades show where technology fuel costs in the model are scaled down by a given percentage. Renewable fuels are not shown here as those fuel costs are the same no matter where the technology is, and those fuel costs are null. The natural gas multipliers were specifically updated for this study.

Transmission Input Dataset

WIS:dom-P resolves the transmission topology of the modeled grid down to each 69-kV substation resolution. A closer view of Maryland is observed in **Figure D-19**.

Model run time is a direct tradeoff to the level of detail and resolution. For the Phase 1 model runs, the transmission topology was aggregated to county-level resolution for Maryland and state-level resolution for the other PJM states. For Phase 2, transmission topology was only aggregated to state-level resolution for all states, including Maryland. For Phase 1, this reduced-form is shown in **Figure D-20** for all of PJM The links occur at the state or county population-weighted centers.

By default, VCE's model assumes the following regarding transmission:

1. All transmission expansions are new builds with double-circuited lines, with substations every 100 miles; and
2. Retired plants opened new transmission capacity on existing lines at the retired generation node.

For this project, VCE added the ability to upgrade existing lines via rebuilding:

1. Upgrade potential of all lines within the model domain is evaluated assuming that lines can be upgraded only one voltage class (e.g., from 138-kV to 230-kV);
2. Upgrades will only be single-circuited lines;
3. Upgrades assume a line upgrade as well as transformer upgrade necessary; and
4. Cost numbers were drawn from a PJM report on transmission options for offshore wind.[28]

Figure D-21 shows these costs. For this project, the rebuild costs (fifth column in table below) were incorporated, not the reconductoring costs (third column).

The model upgrades are for transmission required to interconnect new generation or to more efficiently use existing generation. The model still includes an option for new transmission lines. First, the model considers transmission line upgrades. There is an upper limit on how big the upgrade is (i.e., one voltage class). Once the line hits that ceiling, any additional transmission capacity will come from building new transmission lines during any given investment year.

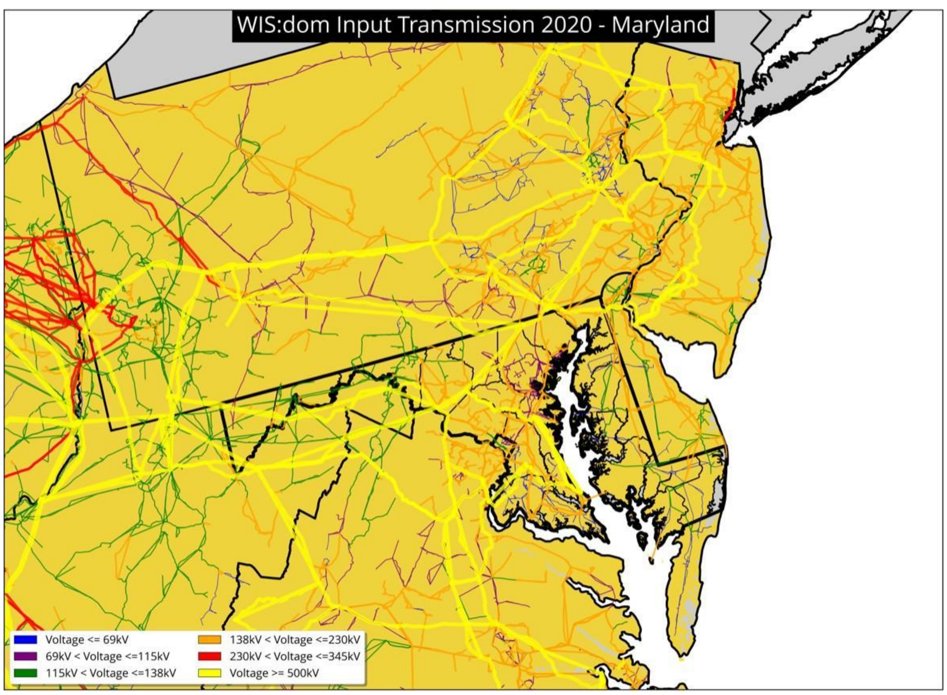

Figure D-19. Model domain with existing 2020 transmission down to 69-kV. This excludes lines that go outside of the domain. This is a closer view of Maryland.

[28] PJM, *Offshore Wind Transmission Study: Phase 1 Results*, October 19, 2021, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

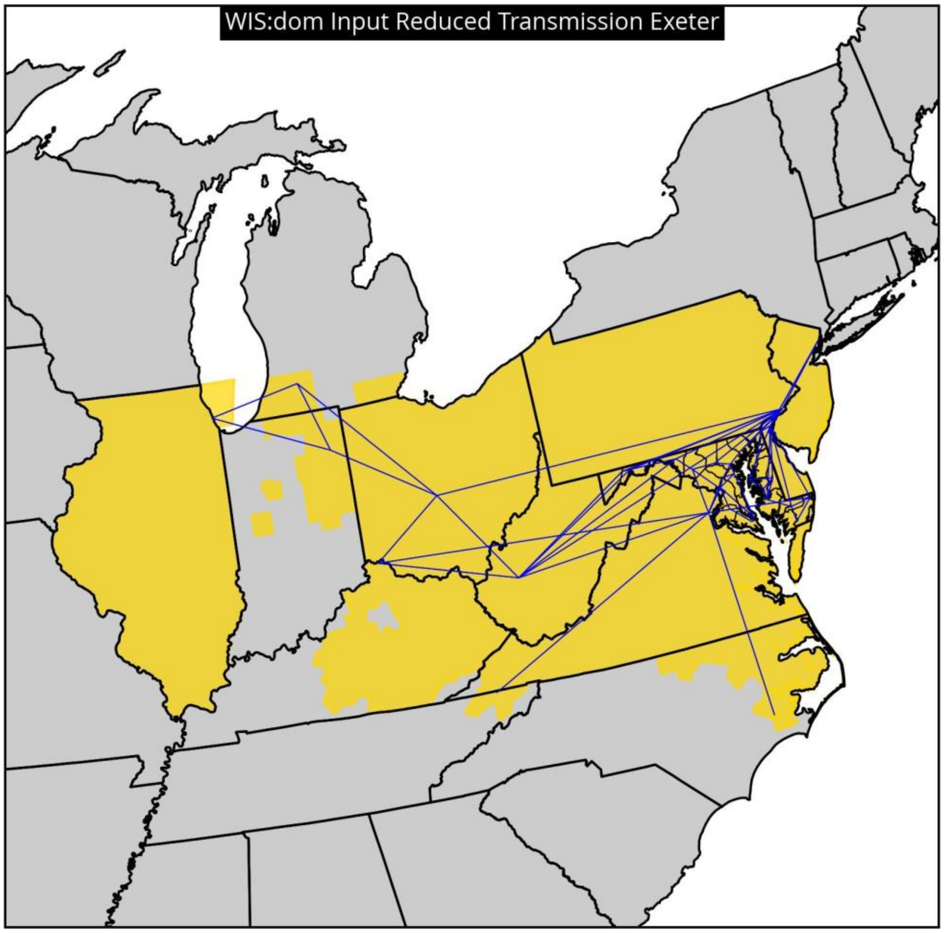

Figure D-20. Model domain with existing reduced-form transmission, inter-boundary connections. This is state-level outside of Maryland. This is county-level within Maryland. This excludes lines that go outside of the domain.

Cost Estimates for New Transformers ($M per unit)	**138 kV** High Side	$4
	230 kV High Side	$6
	345 kV High Side	$9
	500 kV High Side	$25
	765 kV High Side	$45

	Upgrades	Reconductor	Loadings	Rebuild	Loadings
Cost Estimates for Transmission Line Upgrades ($M per mile)	**115 kV & 138 kV**	$0.8	≤ 400 MVA	$1.2	> 400 MVA
	230 kV	$1.2	≤ 1,200 MVA	$1.8	> 1200 MVA
	345 kV	$2.0	≤ 1,800 MVA	$3.0	> 1,800 MVA
	500 kV	$5.5	≤ 4,000 MVA	$8.0	> 4,000 MVA
	765 kV	$8.0	≤ 6,000 MVA	$12.0	> 6,000 MVA
	230 kV Cable	$15 ($M per mile)			

Figure D-21. PJM rebuild costs utilized to upgrade transmission pathways.

Load Input Dataset

There are two components to the load information that are incorporated into WIS:dom-P. The first component is the annual demands forecasted going forward which are binned into the following segments:

1. Conventional load
2. Space heating load
3. Transportation load
4. Water heating load
5. Hydrogen production load

The conventional load covers uses such as space cooling, lighting, and cooking loads. Hydrogen production load will be negligible unless specified in certain scenarios. In the three base case scenarios, the hydrogen economy is not considered.

The annual loads are incorporated into the model for each load zone. For the Phase 1 model run, the load was brought in at state-level for states within PJM, other than Maryland. Maryland was modeled at higher, county-level spatial granularity. The total load for Maryland was broken out by the population in each county. The images below do look at Maryland as a whole for simplicity. For Phase 2, load was modeled at state-level for all states, including Maryland.

The incorporation of the CEJA legislation in Illinois brought changes to the annual loads to Illinois. In this case, the deemed annual savings and energy efficiency goals were incorporated into the annual loads going forward for Illinois. The deemed savings was part of the switch from annual energy efficiency savings targets to cumulative persisting savings targets under Illinois' Future Energy Jobs Act of 2016. When Illinois changed the energy efficiency programs to focus on longer-term savings, credit was given for the longer-term savings that were already in place from the energy efficiency investments that existed previously. **Figure D-22** shows how the incorporation of the expected programs will change the total annual loads in Illinois.

Figure D-23 shows the annual growth modeled for each load sub-sector for PJM. This includes the CEJA changes brought in for Illinois. **Figure D-24** shows the same for Maryland. In both regions, the load decreases in the shorter term as more energy-efficient systems and programs are expected to reduce load. Beyond 2030, load is modeled to continually increase out to 2040. In both PJM and Maryland, that growth is expected to come from transportation and conventional loads predominantly. Maryland load totals are expected to increase around 17% in the business-as-usual load growth between 2020-2040.

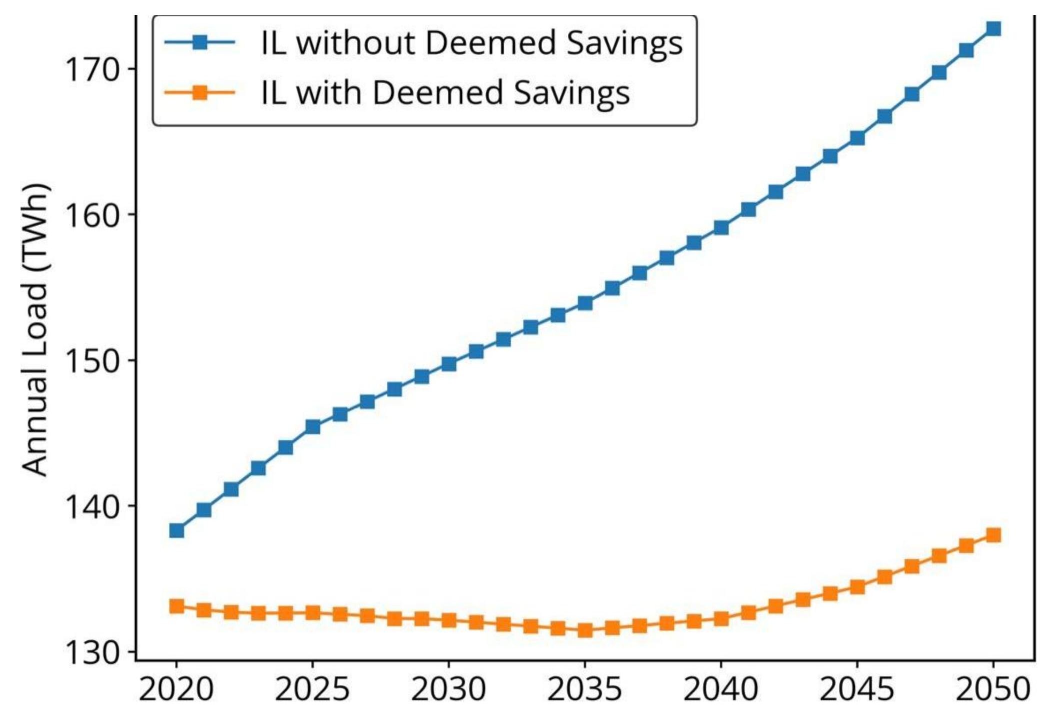

Figure D-22. The effects of incorporating the Illinois CEJA deemed savings and energy efficiency legislative pieces into the total annual loads across investment periods for Illinois.

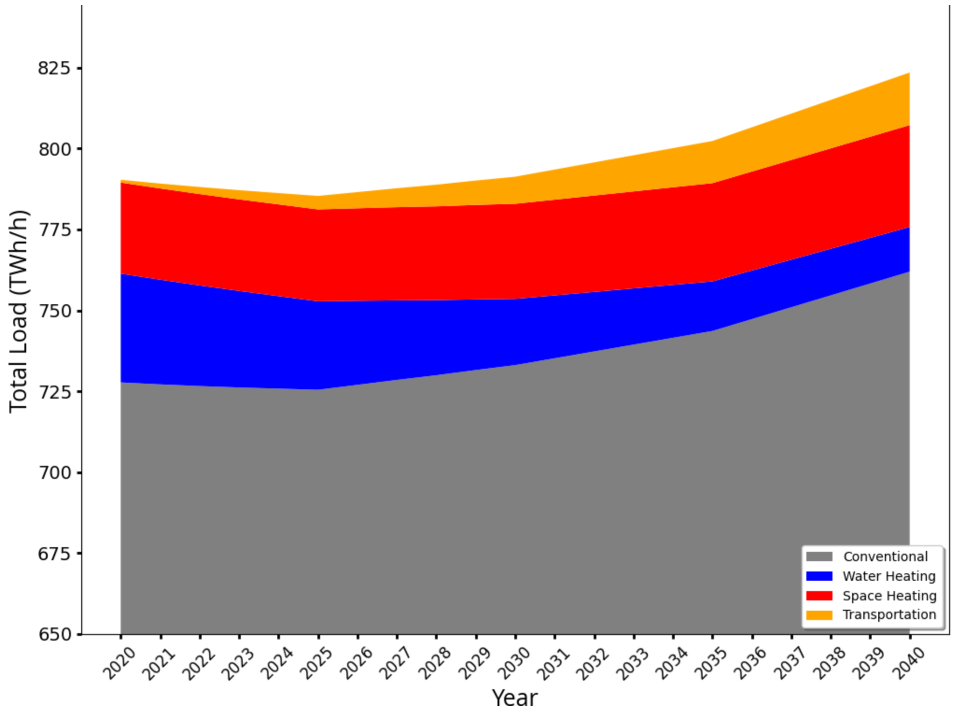

Figure D-23. The VCE business-as-usual annual loads for all investment periods broken out by category.

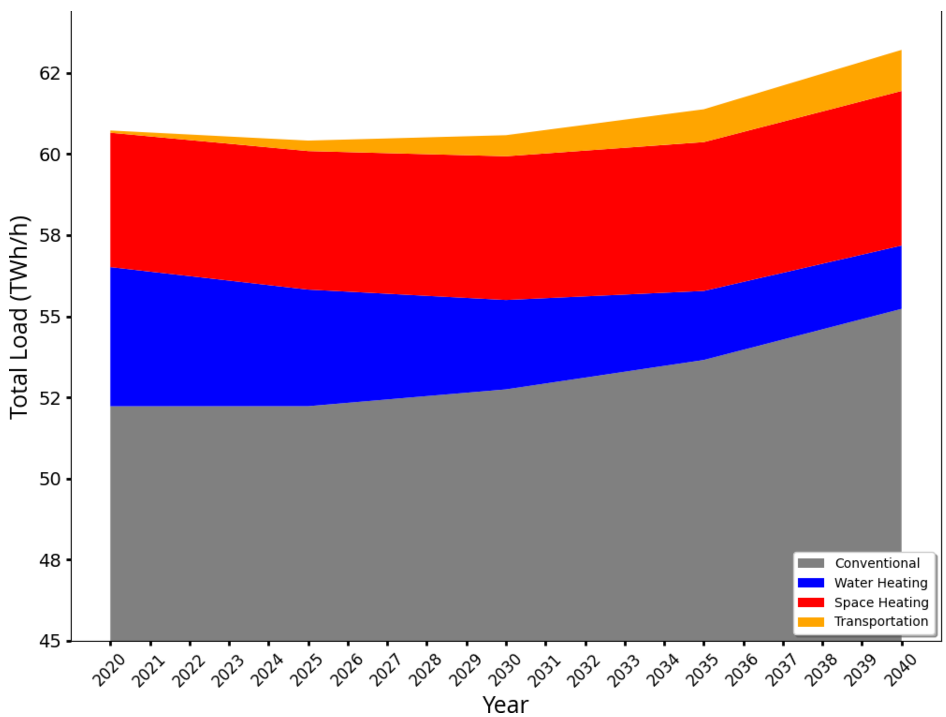

Figure D-24. The VCE business-as-usual annual loads for all investment periods broken out by category.

The second component to the load data is the temporal profile patterns of the load over a given weather year. This is aligned with the HRRR weather data used in the model that is tied to the resource availability for renewable energy plants, transmission derating, etc. Load and weather are innately tied together and that is reflected in the model as well. The demand profiles are computed using a combination of weather data and Federal Energy Regulatory Commission Form 714 (FERC-714) data. The FERC-714 data provides total demand by reporting agency over the Continental United States (CONUS) at an hourly time resolution. The created demand dataset is split into VCE's four main load buckets: (1) space heating demand; (2) water heating demand; (3) transportation demand; and (4) conventional demand (including industrial demands, residential cooling demands, lighting demands, and so on). This matches the bucketing of the annual demand forecasts. Using the weather data, profiles for space heating, water heating, and transportation are created for the required temporal and spatial resolution.

The 2020 hourly demand components for PJM are shown in **Figure D-25** for an entire year and are shown for Maryland in **Figure D-26**. The conventional load makes up the largest fraction of the total load with a peak demand around 130 GWh/h occurring in summer for PJM and around 10 GWh in Maryland during the summer. The space and water heating are smaller components of the total load with peaks in the winter periods. Transportation is a negligible part of the electricity demand in 2020 as most of the vehicles run on gasoline and diesel.

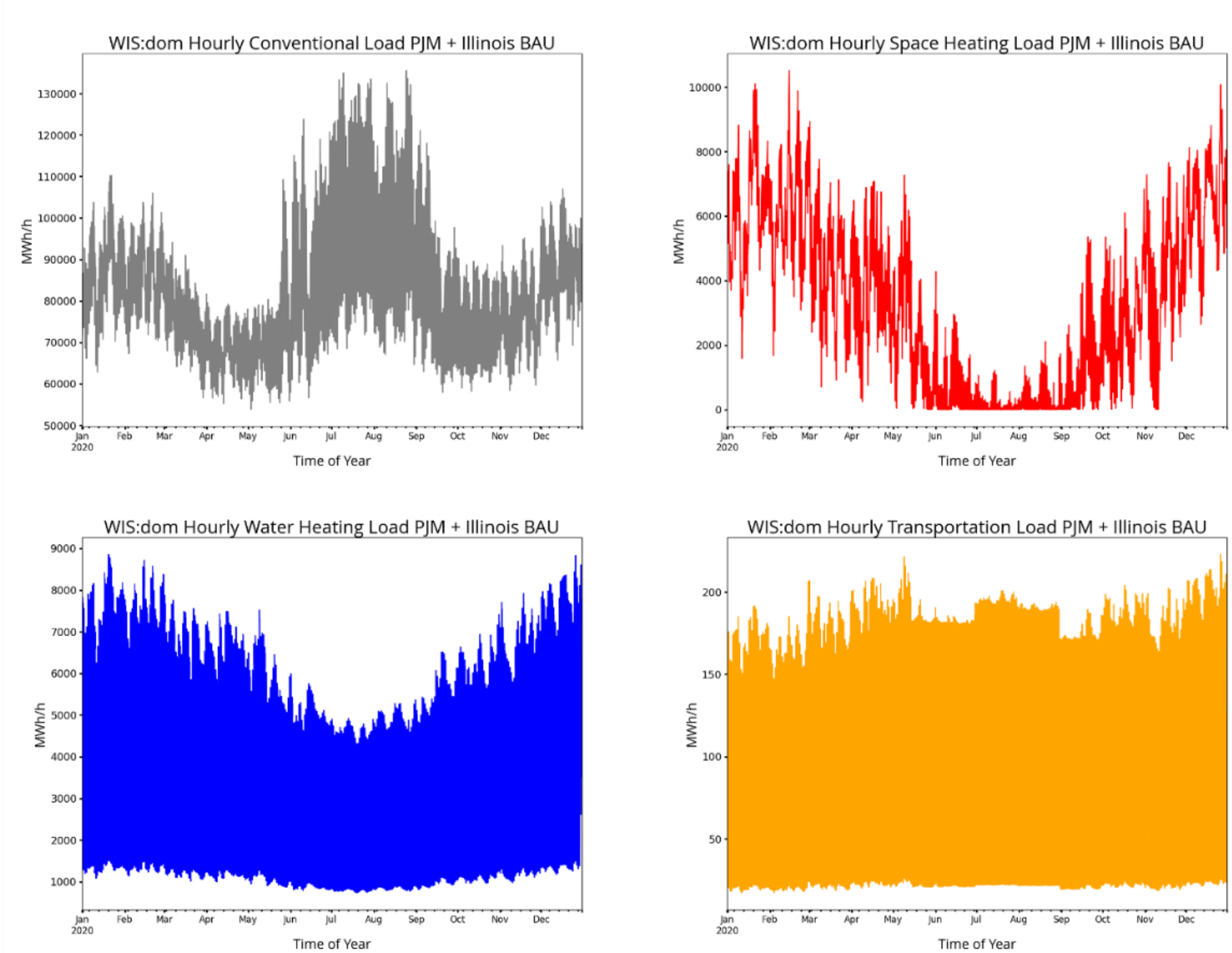

Figure D-25. Aggregated demand profiles (MWh/h) for PJM in 2020. Conventional (top left), space heating (top right), water heating (bottom left), and transport (bottom right).

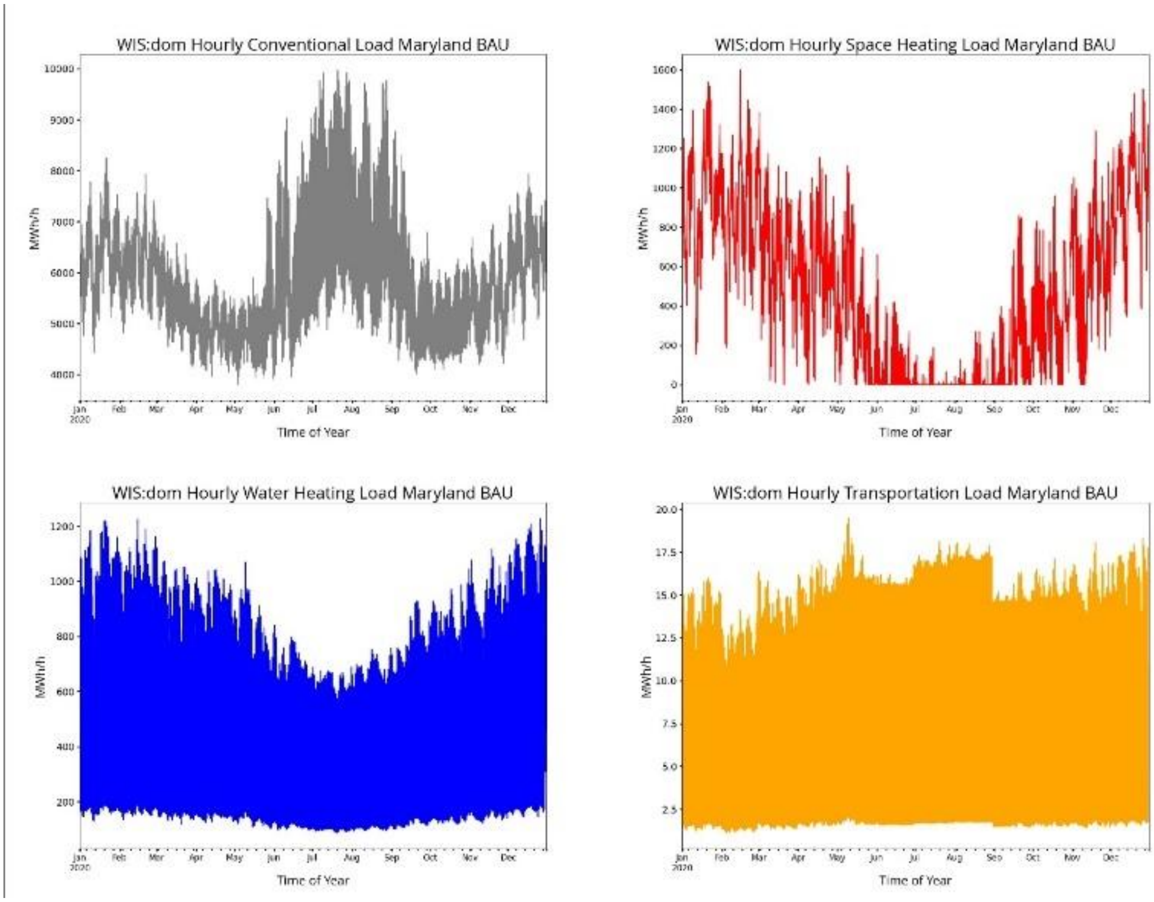

Figure D-26. Aggregated demand profiles (MWh/h) for Maryland in 2020. Conventional (top left), space heating (top right), water heating (bottom left), and transport (bottom right).

The change in components of the electricity demand by 2040 as a result of business-as-usual load growth is shown in **Figure D-27** for PJM and **Figure D-28** for Maryland. The conventional load in PJM increases by almost 10 GWh/h from 2020 with a new peak load near 140 GWh/h. The space heating load is also increased slightly as some part of the population switches from heating with natural gas to heat pumps. Water heating load decreases, as any increases in electricity load due to switching from gas to electric heating are offset by updating the current stock of water heaters to newer, more efficient electric water heaters. The transportation load grows as well with a new peak load just over 4 GWh/h during the winter and spring periods.

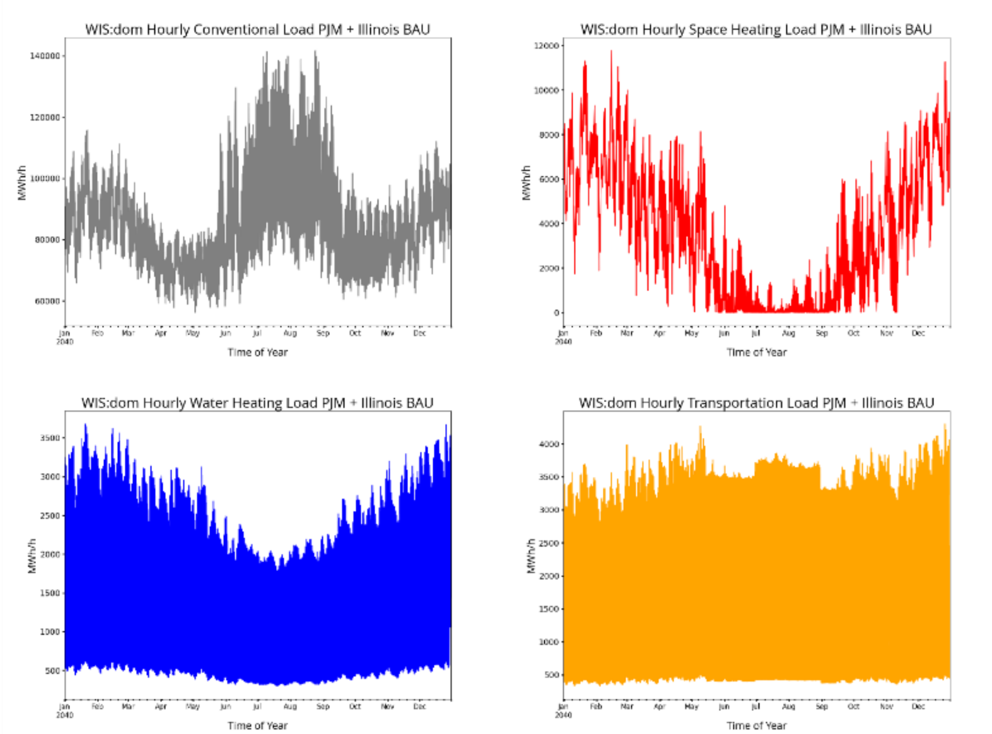

Figure D-27. Aggregated demand profiles (MWh/h) for PJM in 2040. Conventional (top left), space heating (top right), water heating (bottom left) and transport (bottom right).

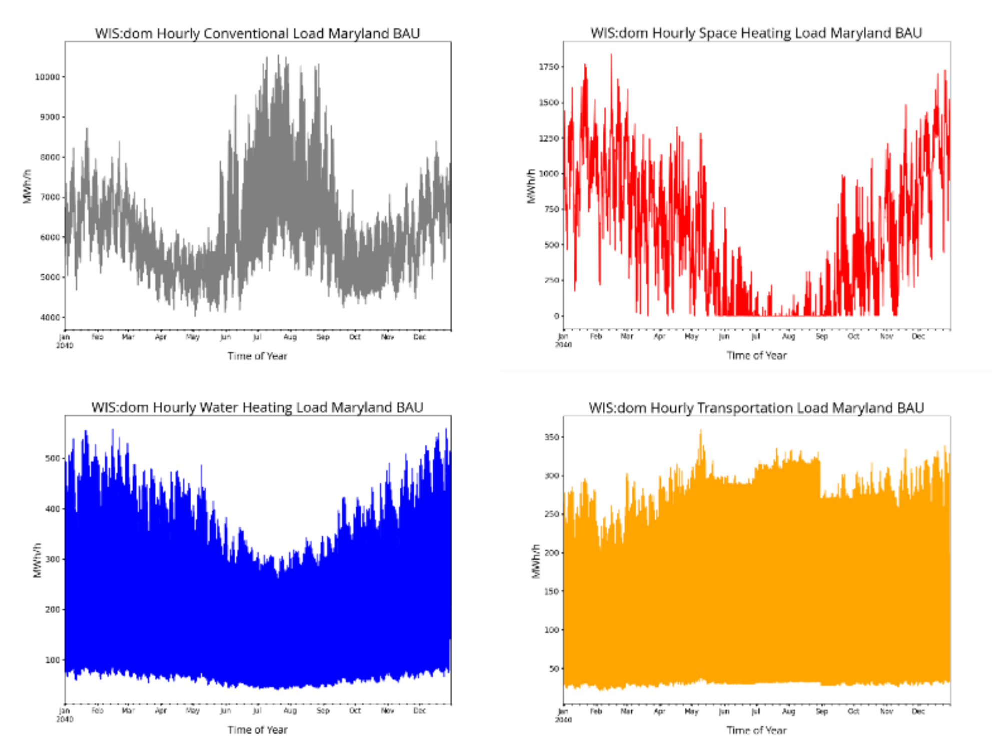

Figure D-28. Aggregated demand profiles (MWh/h) for Maryland in 2040. Conventional (top left), space heating (top right), water heating (bottom left) and transport (bottom right).

The total shape of all load components combined over an entire year is shown for PJM and Maryland in 2020 in **Figure D-29** and **Figure D-30**. The yearly profile shapes are fairly similar. Maryland sees more pronounced load in winter along with a wintertime peak. In PJM as a whole, the summer is where the highest load occurs.

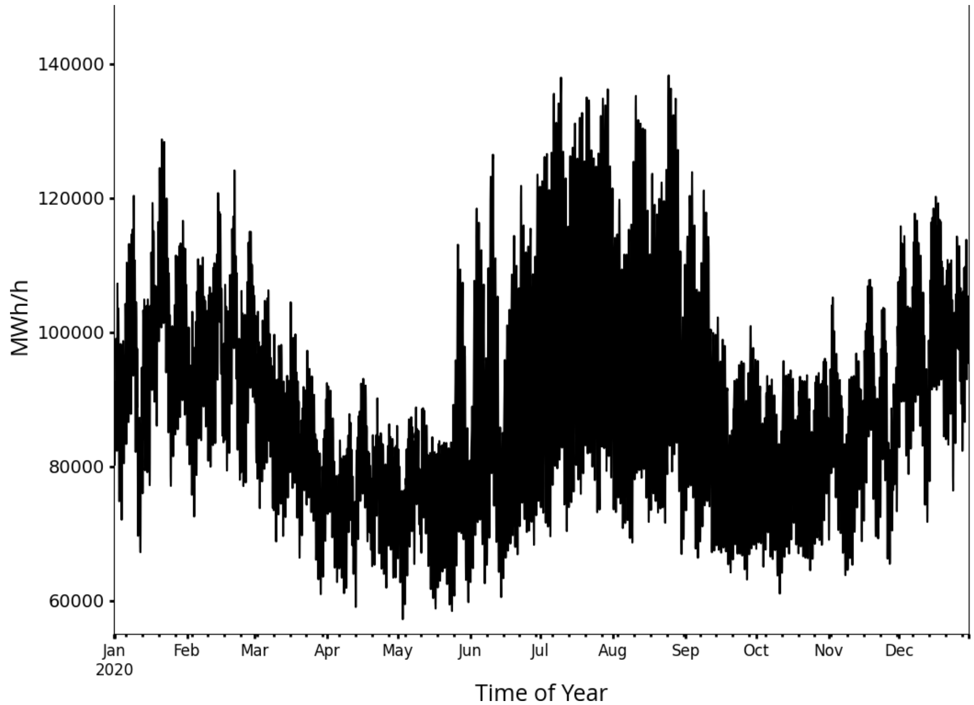

Figure D-29. Aggregated yearly load shape for PJM in 2020.

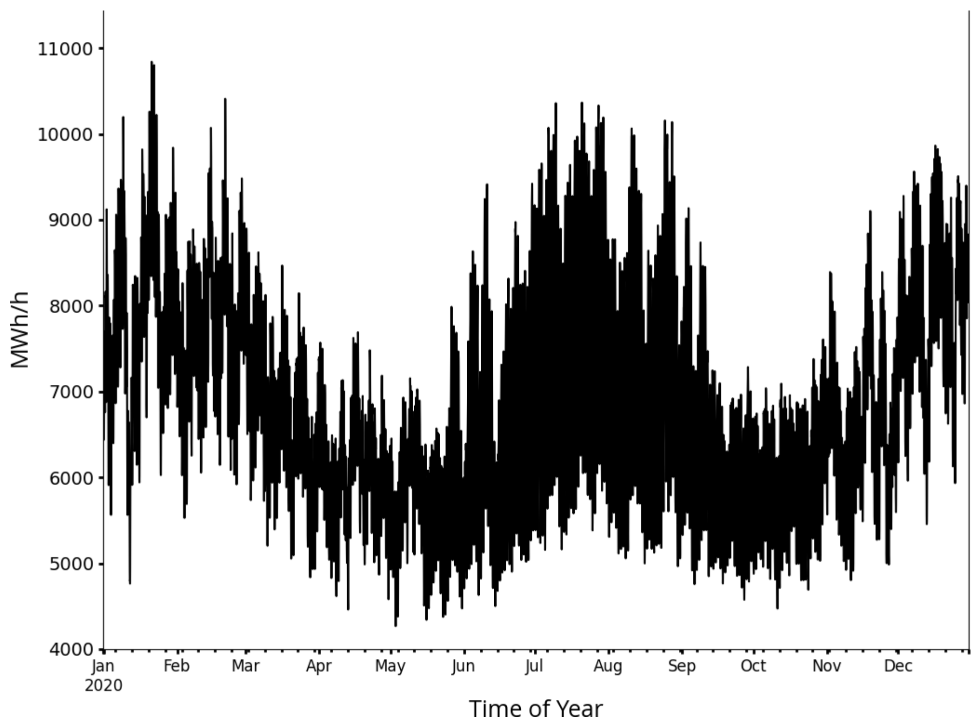

Figure D-30. Aggregated yearly load shape for Maryland in 2020.

The yearly shape observed above maintains itself in 2040 for both PJM and Maryland in the BAU setup. The biggest difference is the hourly magnitude.

The daily shape of the load will be a driver of which resources are selected and correlate best with load. Looking at renewables in particular, the correlation of load can affect the build-out of certain types of renewables. **Figure D-31** shows this daily load shape in 2020 for PJM. For both PJM and Maryland, a peak is observed in the morning and another in the evening hours, with the evening load peak being the highest. During nighttime hours, load is lower.

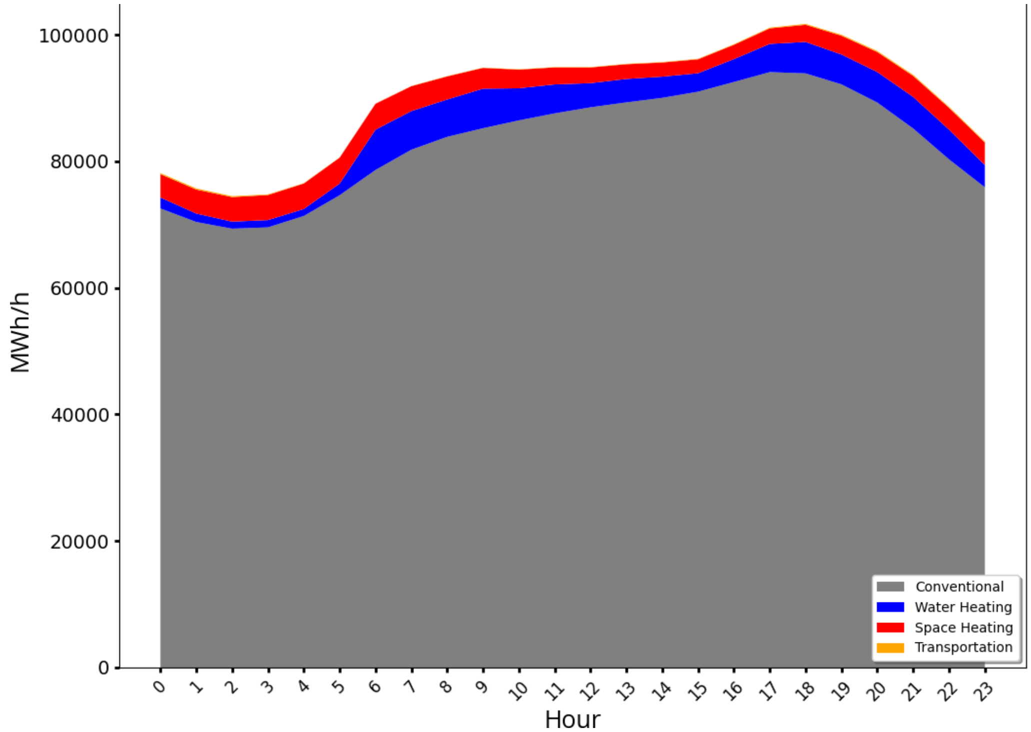

Figure D-31. Average daily demand by sector in PJM for 2020 (ET).

The same daily view of load is observed in **Figure D-32** for PJM in 2040. The shapes are generally the same as 2020 except that the increase in transportation load increases load during the nighttime hours. It is expected that vehicle electrification at scale can change the shape and peak of the loads into the nighttime hours. Due to a meteorological phenomenon known as boundary layer decoupling at night, **Figure D-32** shows that wind resource is higher in the evening hours which means higher correlation for that resource with load.

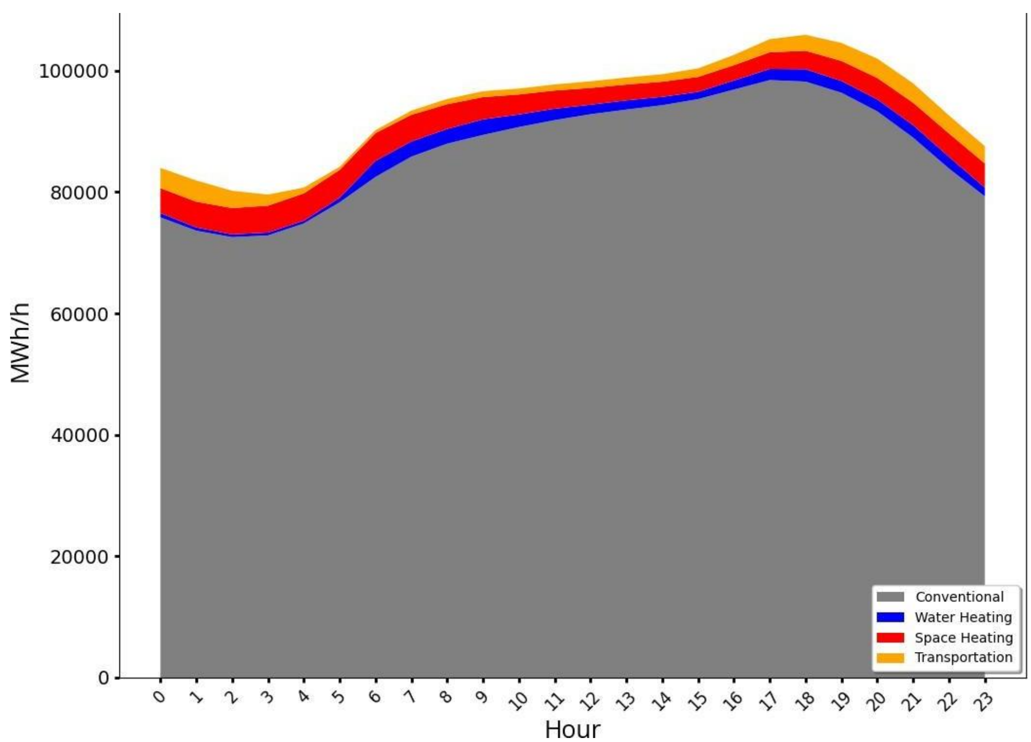

Figure D-32. Average daily demand by sector in PJM for 2040 in EST.

Two high electrification scenarios were modeled, one for the 100% RPS case and one for the 100% clean case. **Figure D-33** through **Figure D-36** compare the annual demand for water heating, space heating, transportation, and conventional applications. Electricity demand for conventional applications covers uses such as lighting and cooking. VCE assumes widespread conversion of space heating and water heating to more efficient heat pumps and heat pump water heaters, respectively. VCE also assumes that about 90% of light duty vehicles will be electric vehicles by 2050. Finally, VCE assumes demand is participating in the electric market and responding to market price signals. In doing so, VCE projects demand flexibility, meaning that demand can shift from time period to time period, as discussed further below.

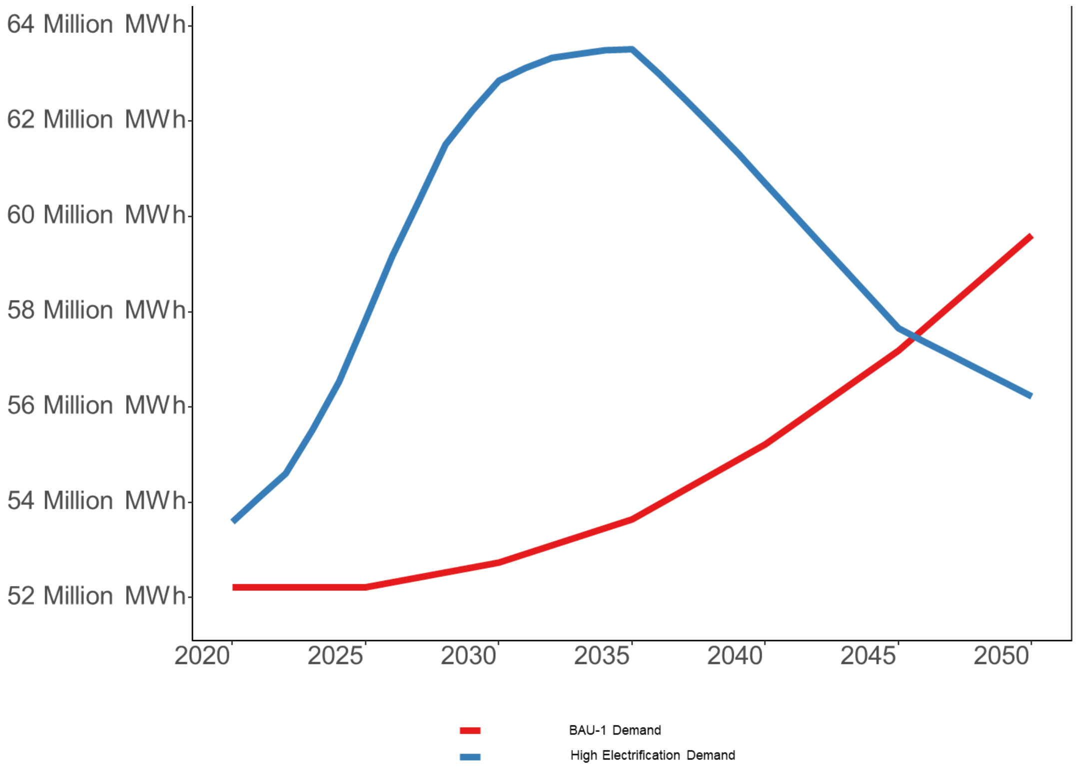

Figure D-33. Annual Demand for Conventional Energy in Maryland

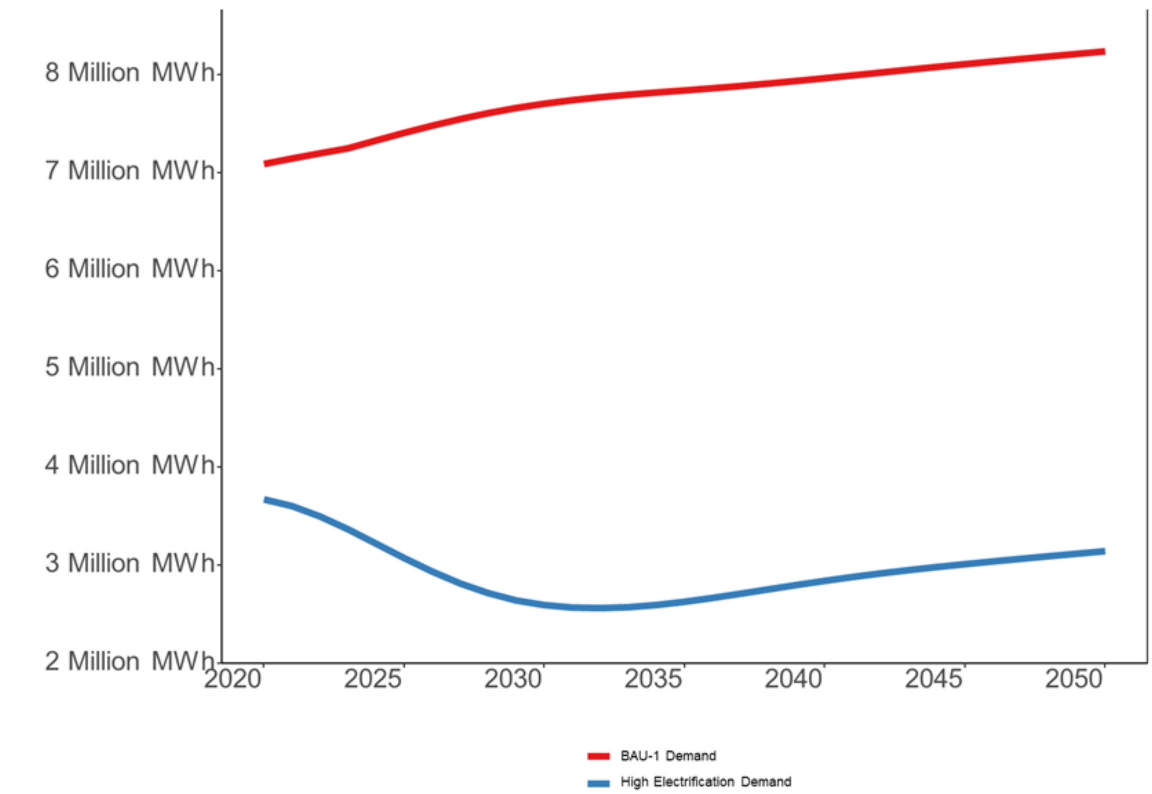

Figure D-34. Annual Demand for Water Heating Energy in Maryland

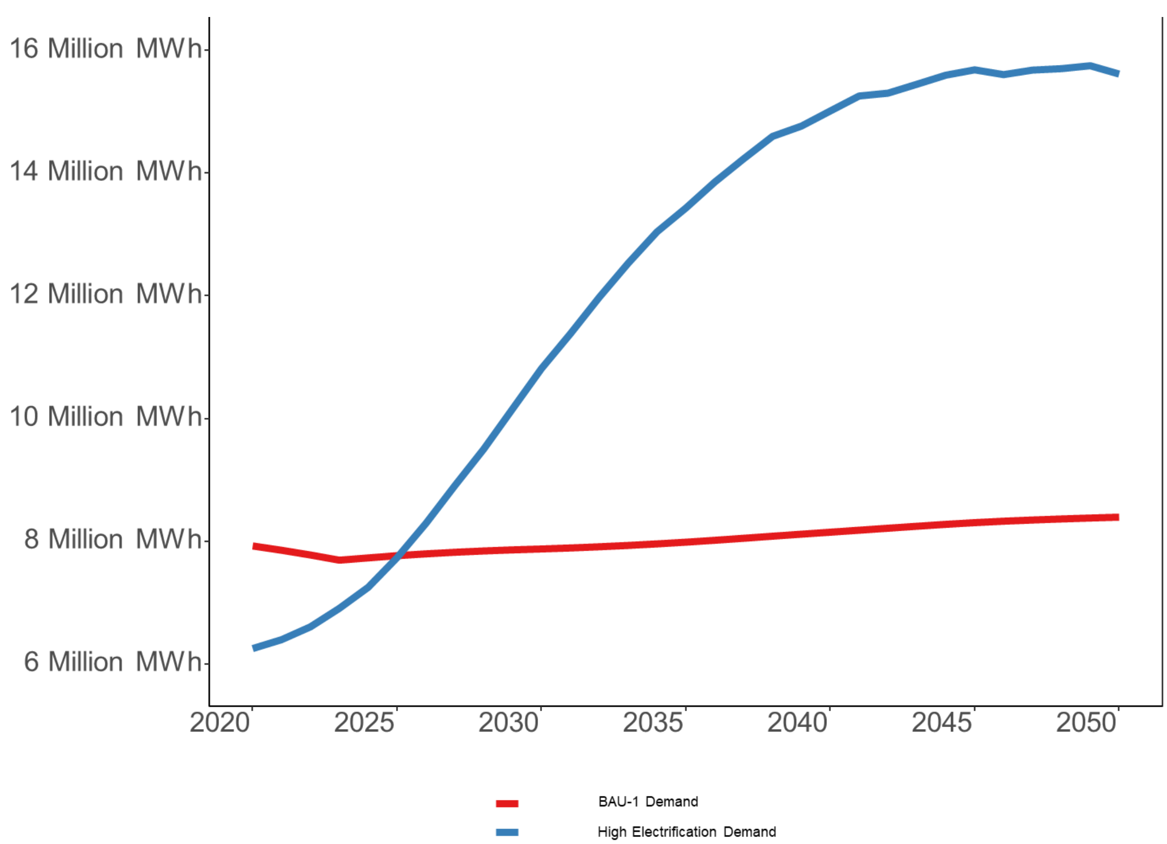

Figure D-35. Annual Demand for Space Heating Energy in Maryland

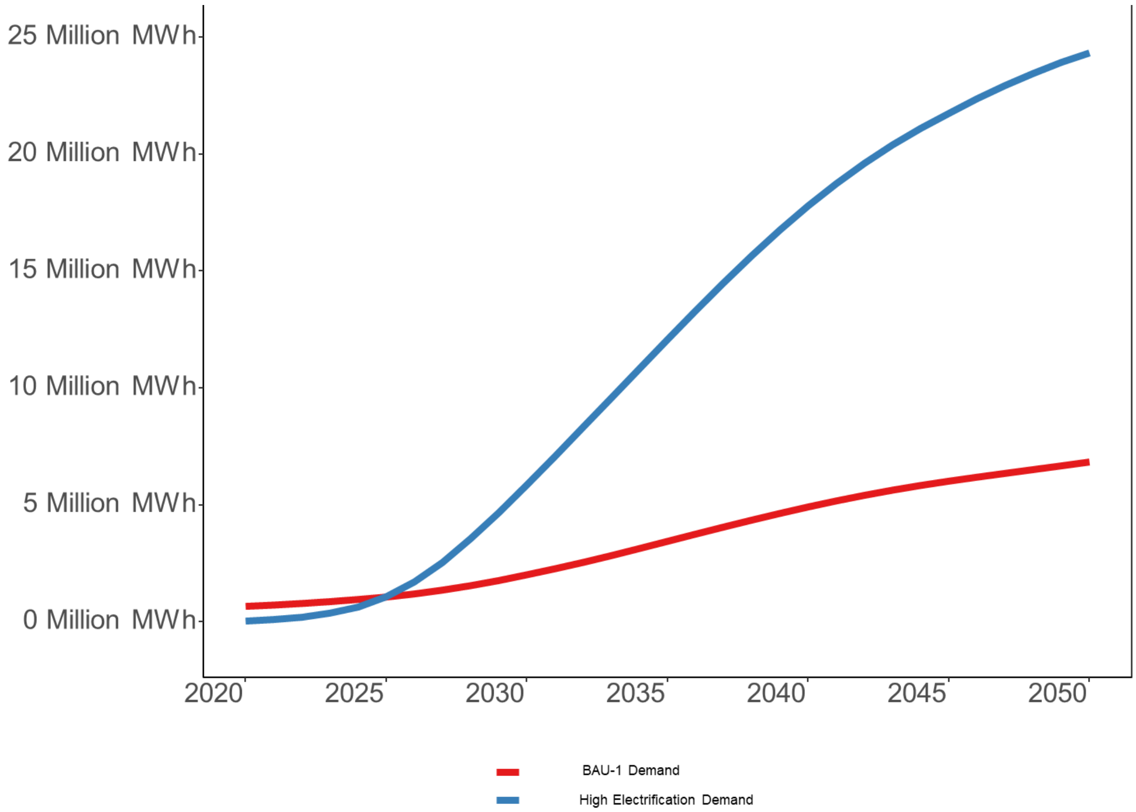

Figure D-36. Annual Demand for Transport Energy in Maryland

Space Heating and Cooling Flexibility Input

It is critical to model the temporal availability of flexibility to ensure a reliable operation of the simulated grid. The demand flexibility is bound by the capacity of the demands themselves as well as the physics of the weather that drives some of the flexibility. Due to physical limitations such as weather conditions and coincident availability, the actual demand flexibility that can be called upon changes at every time-step.

For this project, VCE assumes that the ideal indoor temperature for the building stock is 71.6°F (22°C). To calculate flexibility in space heating, it is assumed that the indoor temperature is allowed to drop to 68°F (20°C). The reverse is true for flexibility in space cooling. The indoor temperature is allowed to increase to 75.2°F (24°C). **Figure D-37** shows the percentage of space heating demand with flexibility that can be called upon in PJM and Illinois at each time-step over the investment periods. **Figure D-38** shows the percentage of space cooling demand with flexibility. When space heating demand is high during the cold winter months, the availability of flexibility is limited in PJM because the ambient air temperature is so low that the buildings would cool below the allowed threshold. The same is true of cooling flexibility in the summer. With warmer ambient temperatures, the indoor temperature will more quickly reach the upper threshold and less flexibility is allowed. Equivalent graphs for Maryland show similar characteristics as PJM.

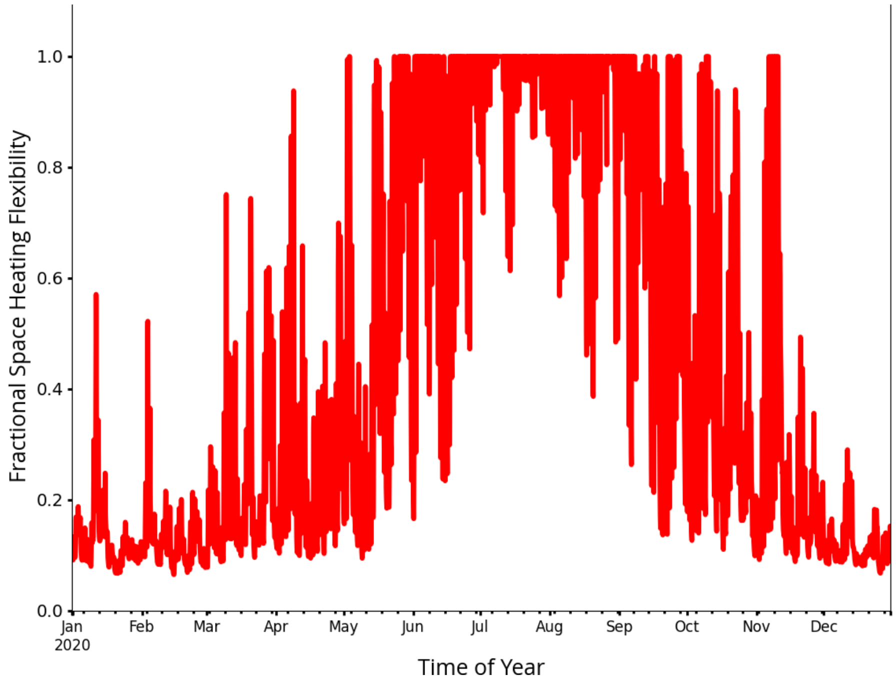

Figure D-37. Percentage of space heating demand with flexibility for PJM and Illinois available to the model to select.

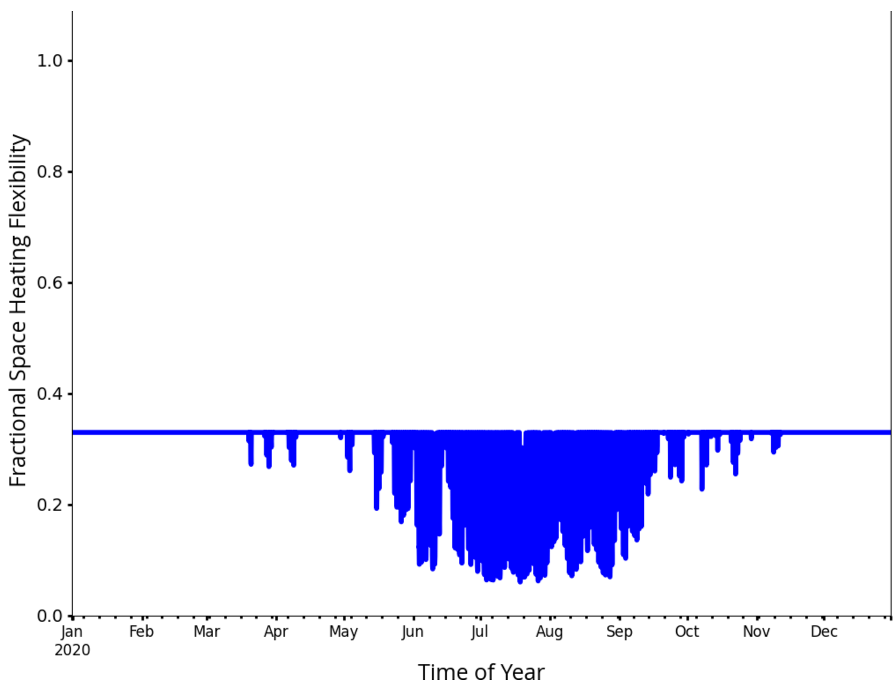

Figure D-38. Percentage of space cooling demand with flexibility for PJM and Illinois available to the model to select.

PJM and Maryland Weather Analysis

This section will analyze the weather data specific to Maryland as well as PJM and Illinois and how the model considers, and ultimately selects and locates, certain renewable energy resources. Wind resources depicted in the figures below are measured at 100 meters above ground level unless otherwise stated. The solar technology is single axis tracking pitched to latitude tilt. Solar capacity factors depicted in the figures below are for direct current. VCE utilizes the 3-km NOAA HRRR weather model as the raw inputs for the weather and power datasets. VCE converted the weather datasets to net capacity factors. These datasets are analyzed here at different spatial and temporal granularity to provide insight into typical renewable resource characteristics across the region. In particular, four years are reviewed, although the model was run over the 2020 weather year. The four years selected are:

1. 2014: Generally higher winds for PJM with lower average solar resource. The Polar Vortex also occurred this year.
2. 2018: Slightly lower than average solar resources for PJM and a more moderate wind regime.
3. 2020: The current initialization year of the model.
4. 2021: A better than average year for solar resource and a lower than average year for wind.

The 3-km / 100-m wind capacity factors are plotted spatially for 2014, 2018, 2020, and 2021 in **Figure D-39**, **Figure D-40**, **Figure D-41**, and **Figure D-42**, respectively. Consistent across all years is higher wind resources in Illinois, northern Ohio and Pennsylvania, the Great Lakes, as well as along the Atlantic shoreline. Pockets of very high wind resources are located along the Allegheny Mountains, which aligns with the locations of many currently operating wind farms. Offshore wind is also shown in the figures below.

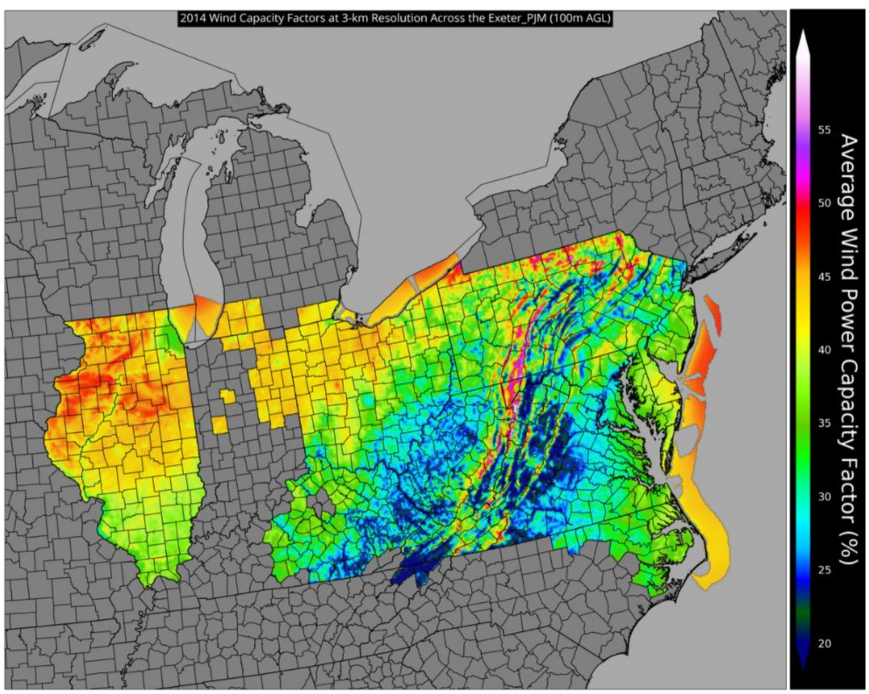

Figure D-39. The 3-km 100-meter wind resource across the study domain in 2014.

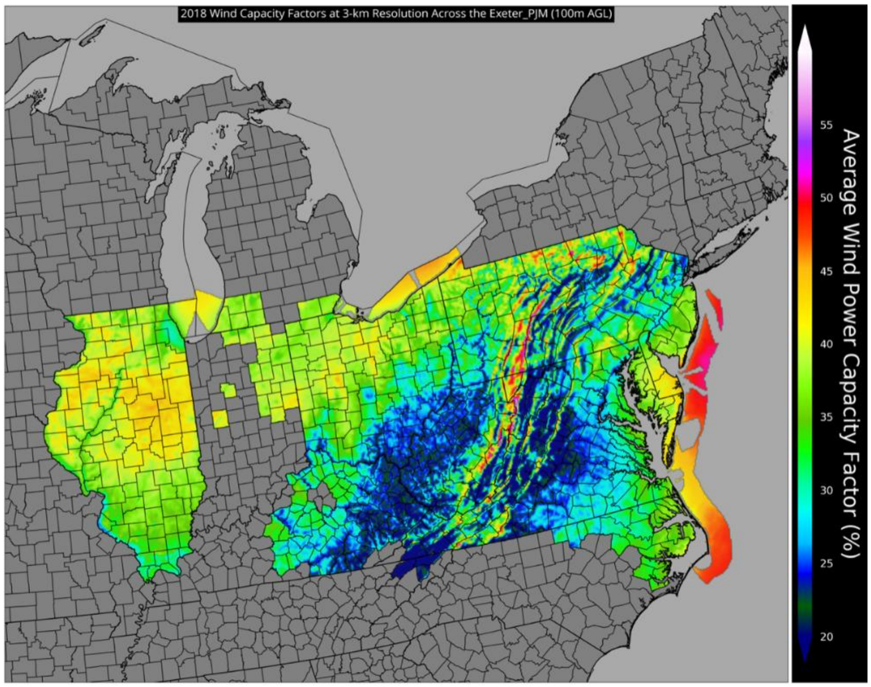

Figure D-40. The 3-km 100-meter wind resource across the study domain in 2018.

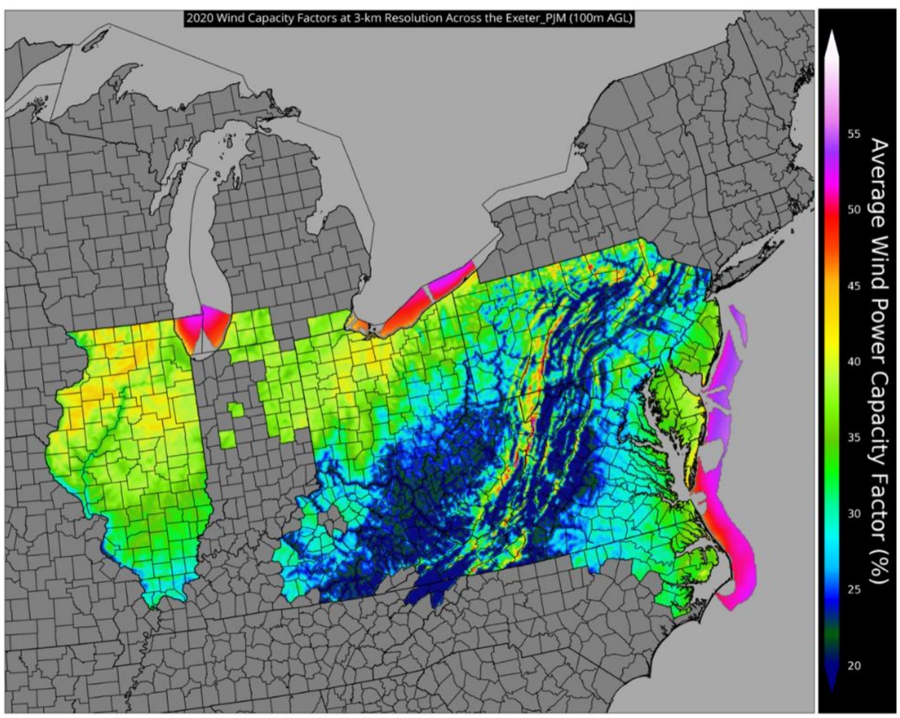

Figure D-41. The 3-km 100-meter wind resource across the study domain in 2020

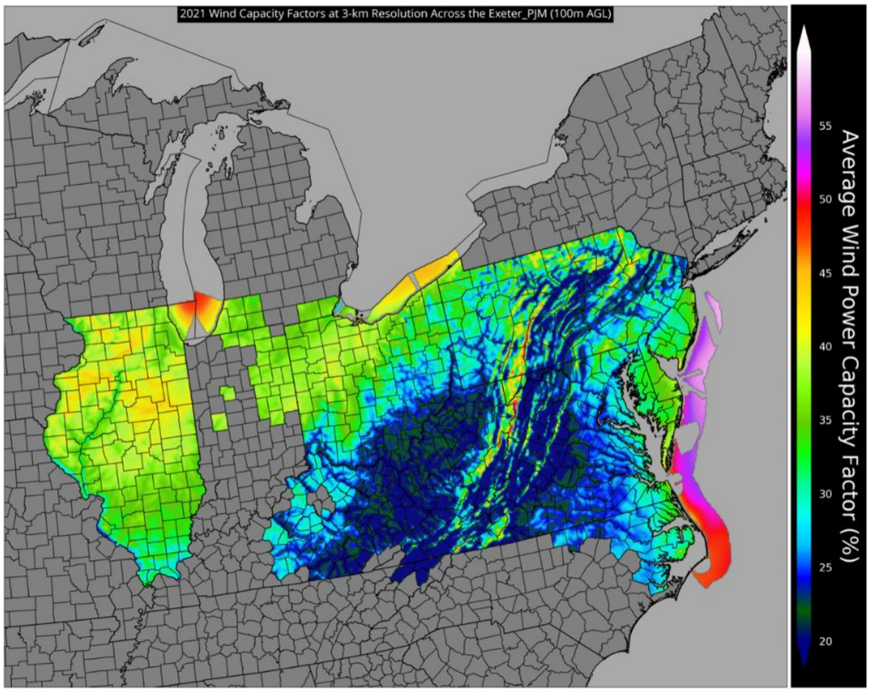

Figure D-42. The 3-km 100-meter wind resource across the study domain in 2021.

Solar capacity factors are plotted spatially for 2014, 2018, 2020, and 2021 in **Figure D-43**, **Figure D-44**, **Figure D-45**, and **Figure D-46**, respectively. Ohio, northeast Pennsylvania, and parts of Michigan have the lowest solar resource across the area studied for this project. Higher solar resources are found closer to the Atlantic coastline and along the eastern side of the Allegheny Mountains.

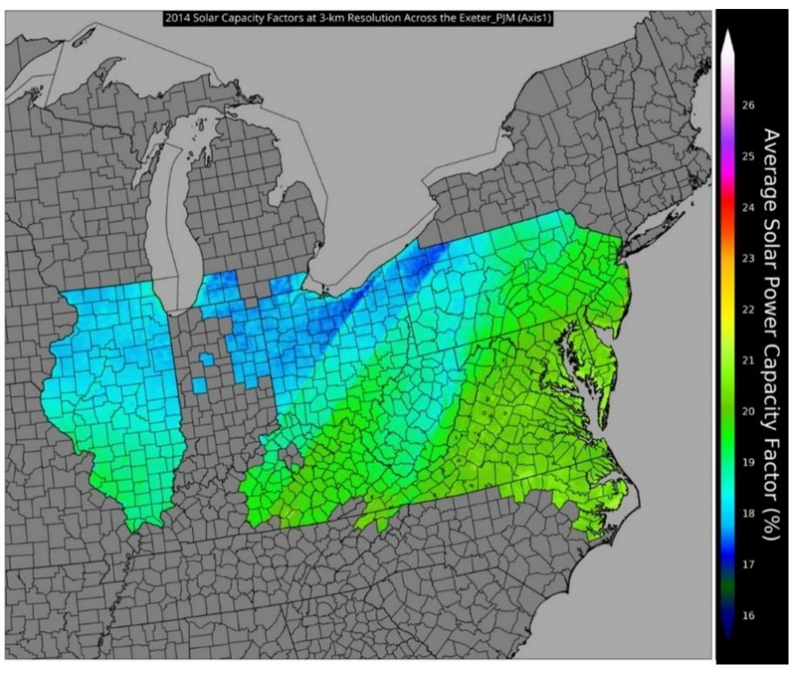

Figure D-43. The 3-km axis-1 solar resource across the study domain in 2014.

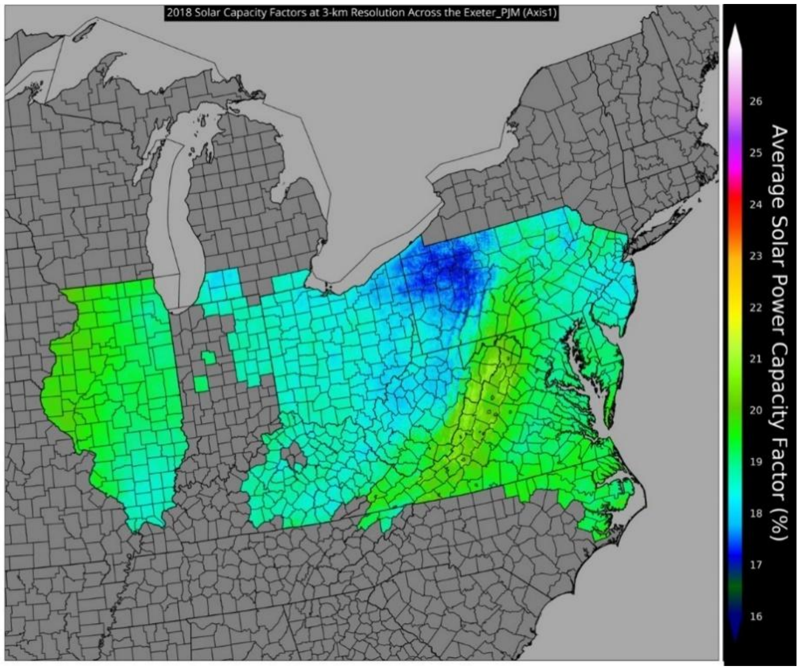

Figure D-44. The 3-km axis-1 solar resource across the study domain in 2018.

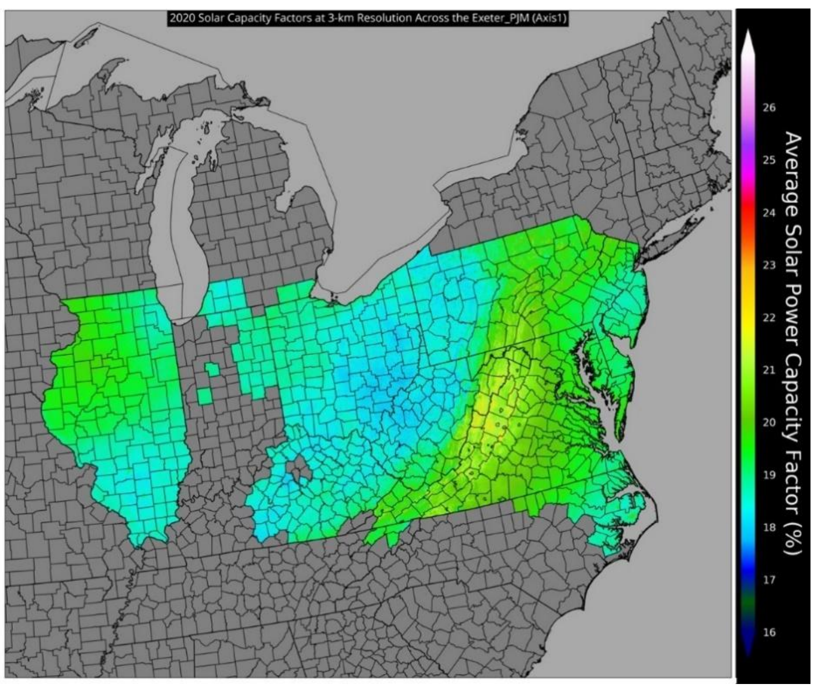

Figure D-45. The 3-km axis-1 solar resource across the study domain in 2020.

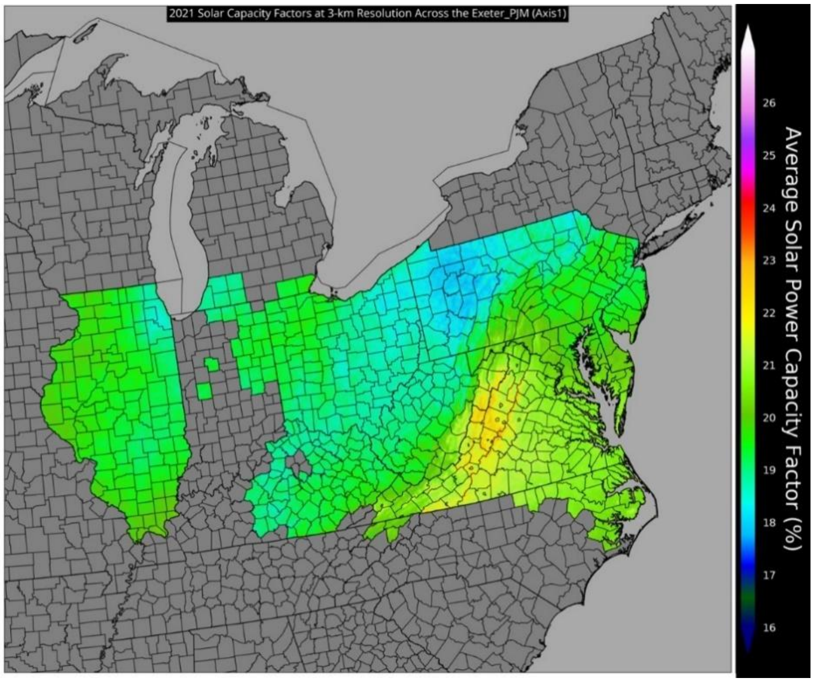

Figure D-46. The 3-km axis-1 solar resource across the study domain in 2021.

State annual average capacity factors are shown for onshore wind for 2014, 2018, 2020, and 2021 in **Figure D-47**, **Figure D-48**, **Figure D-49**, and **Figure D-50**, respectively. The averages include only the portion of the state resource that is incorporated into the domain modeled (i.e., PJM and all of Illinois). Wind resources are stronger in 2014, especially the western and northwestern states of PJM, while lighter wind resources prevailed in 2021. The 2018 and 2020 weather years had wind resource values in between those applicable in 2014 and 2021.

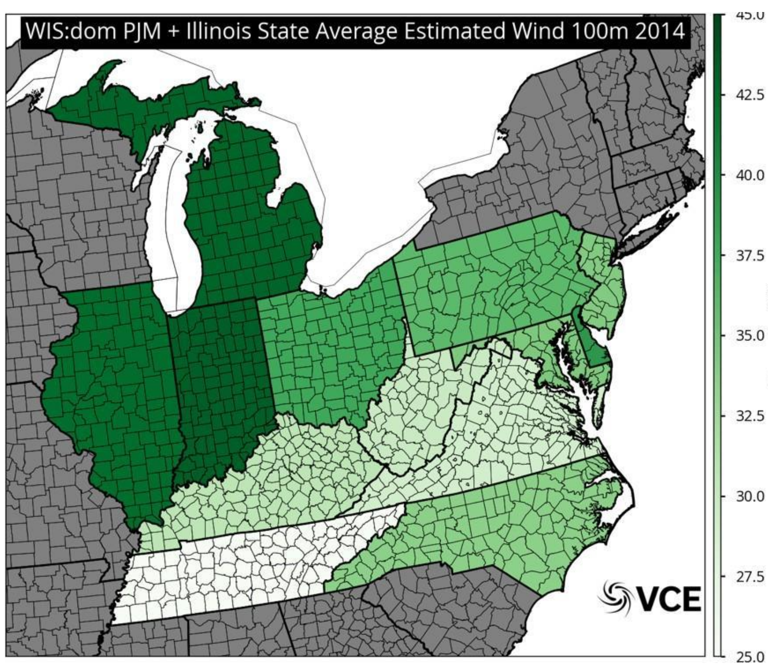

Figure D-47. The average 100-m wind capacity factor (%) for 2014 by state in PJM.

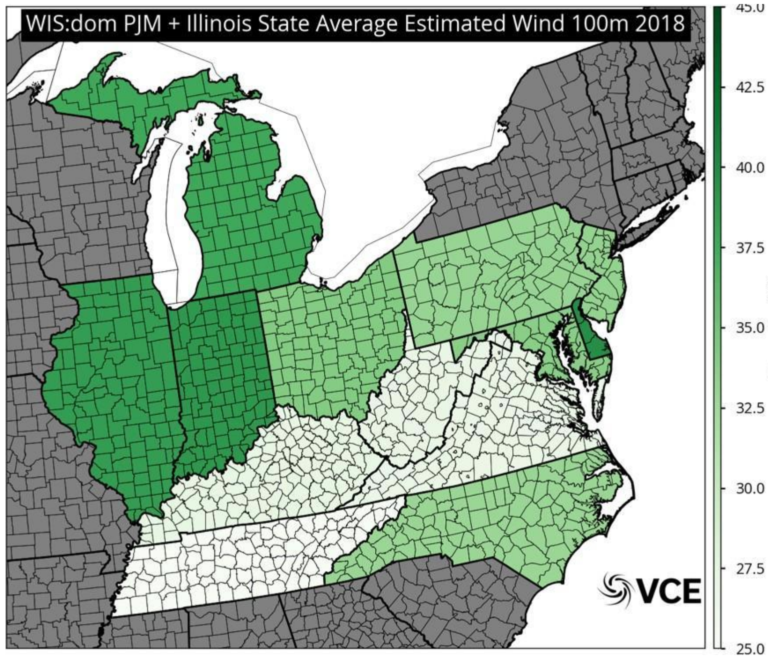

Figure D-48. The average 100-m wind capacity factor (%) for 2018 by state in PJM.

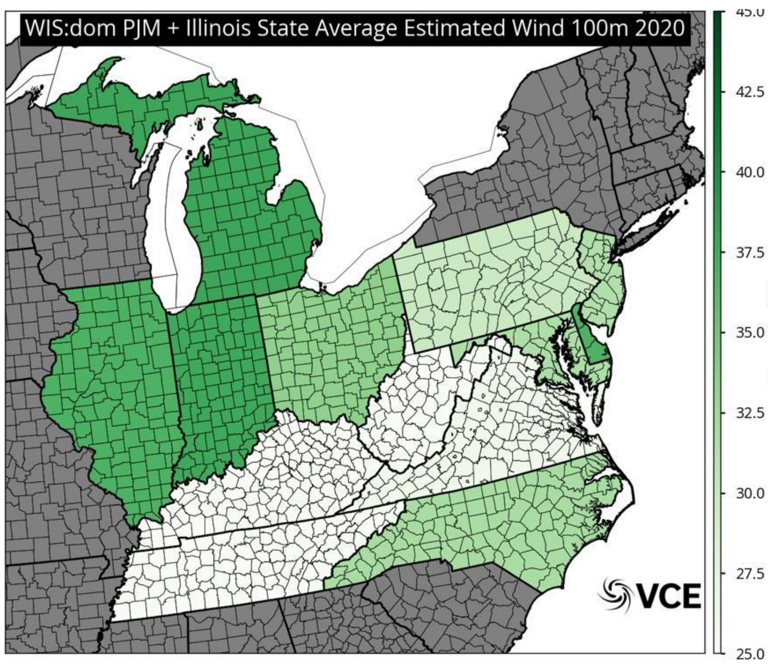

Figure D-49. The average 100-m wind capacity factor (%) for 2020 by state in PJM.

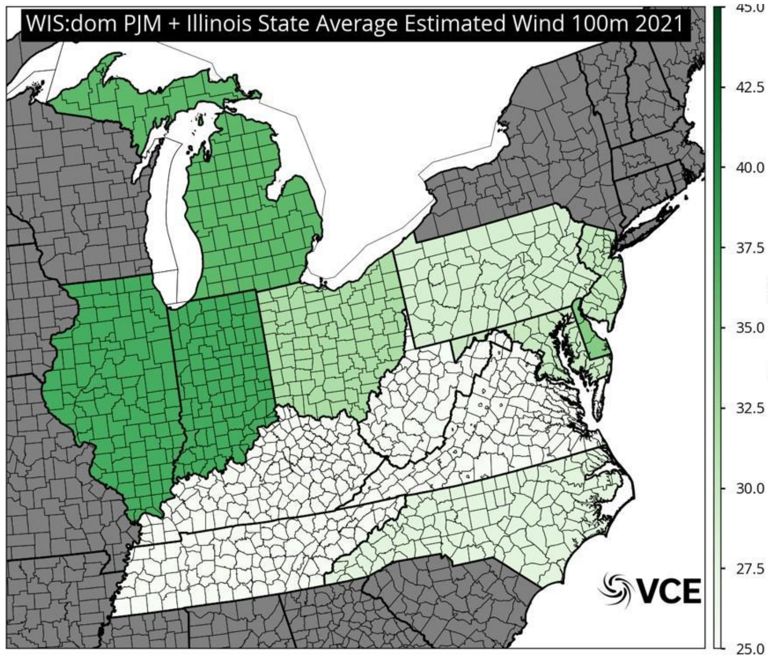

Figure D-50. The average 100-m wind capacity factor (%) for 2021 by state in PJM.

The state annual average capacity factors are shown for offshore wind for 2014, 2018, 2020, and 2021 in **Figure D-51**, **Figure D-52**, **Figure D-53**, and **Figure D-54**, respectively. The averages include only the portion of the state resource that is incorporated into the domain modeled. The 2018 and 2020 weather years had the higher capacity factors for offshore wind. Even for the 2014 and 2021 weather years where offshore wind capacity factors are not as high, the states along the Atlantic Ocean have consistently high quality offshore wind resources.

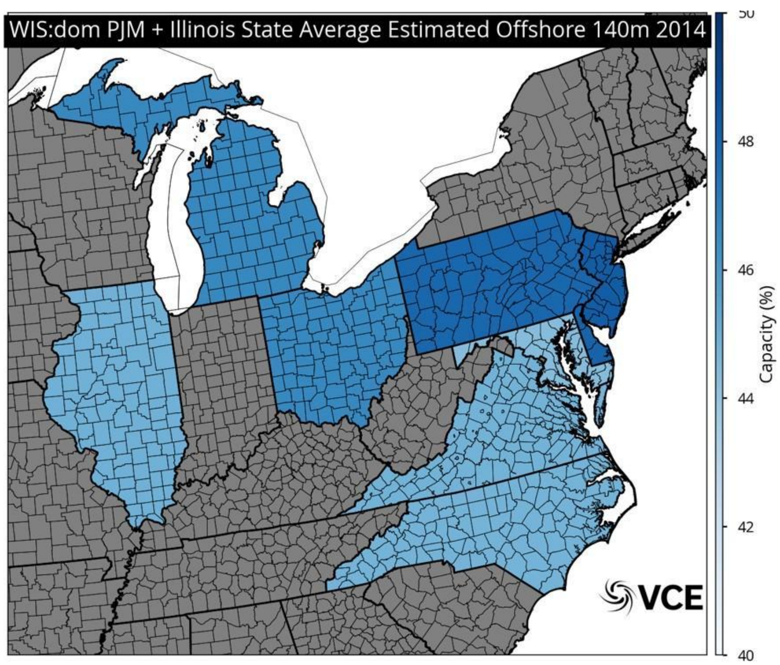

Figure D-51. The average 140-m offshore wind capacity factor (%) for 2014 by state in PJM.

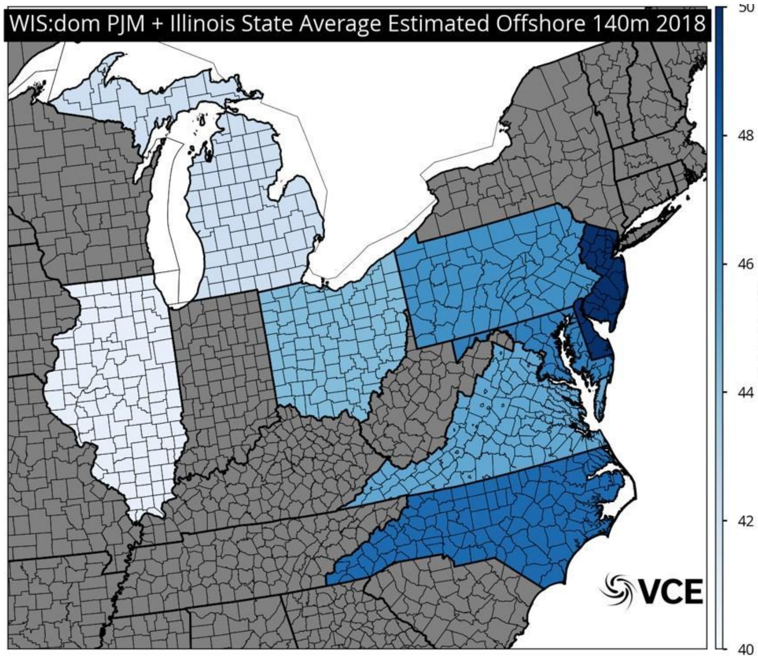

Figure D-52. The average 140-m offshore wind capacity factor (%) for 2018 by state in PJM.

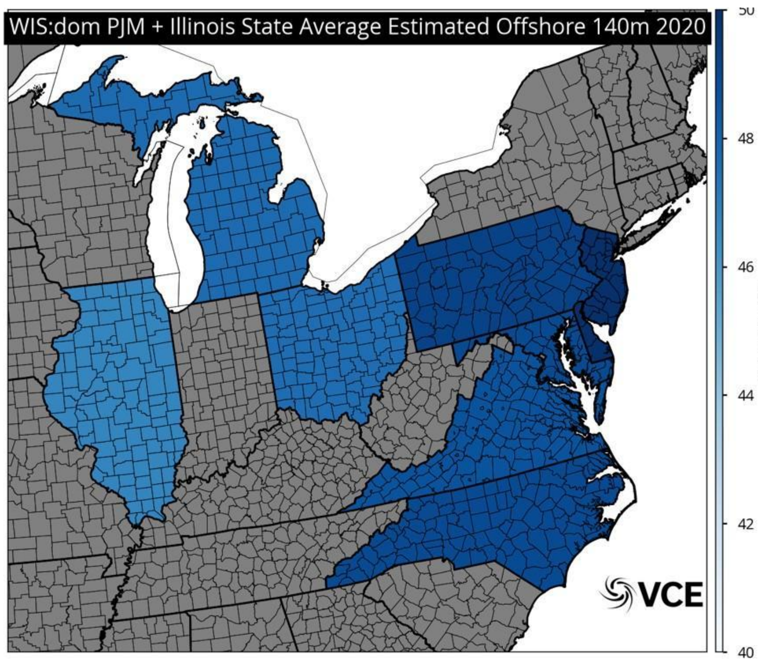

Figure D-53. The average 140-m offshore wind capacity factor (%) for 2020 by state in PJM.

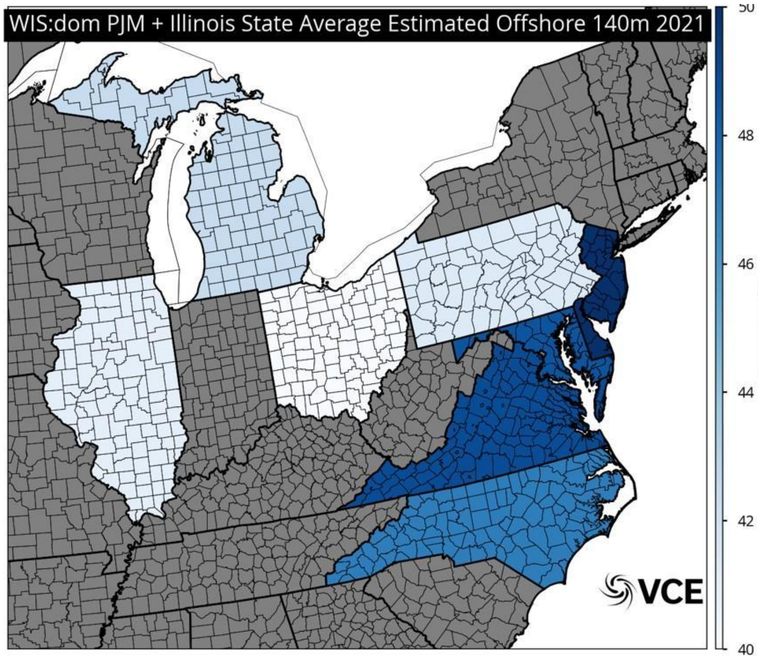

Figure D-54. The average 140-m offshore wind capacity factor (%) for 2021 by state in PJM.

The state annual capacity factor averages are shown for solar for 2014, 2018, 2020, and 2021 in **Figure D-55, Figure D-56**, **Figure D-57**, and **Figure D-58**, respectively. The averages include only the portion of the state resource that is incorporated into the domain modeled. The 2020 and especially the 2021 weather year show higher solar annual capacity factors, while solar is low across the western portion of the domain, but higher solar resource on the lee-side of the mountains along the Atlantic coast in 2014. One factor to note is how annual capacity factors for solar are relatively uniform across the states with a narrow spread in state average capacity factor values. There is far less uniformity observed for the onshore wind resource. Offshore wind is more uniform in statewide capacity factor averages than onshore wind, though still observes more variation than solar spatially.

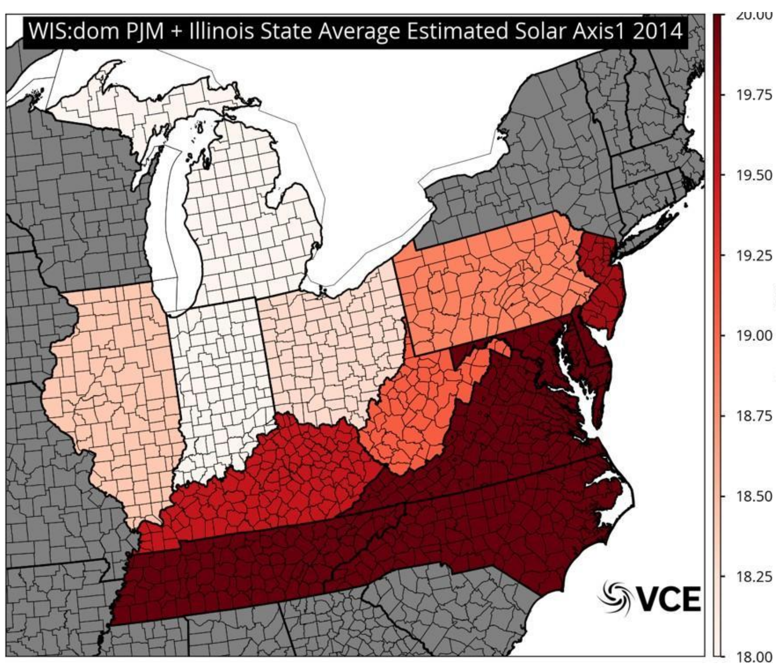

Figure D-55. The average axis-1 solar capacity factor (%) for 2014 by state in PJM.

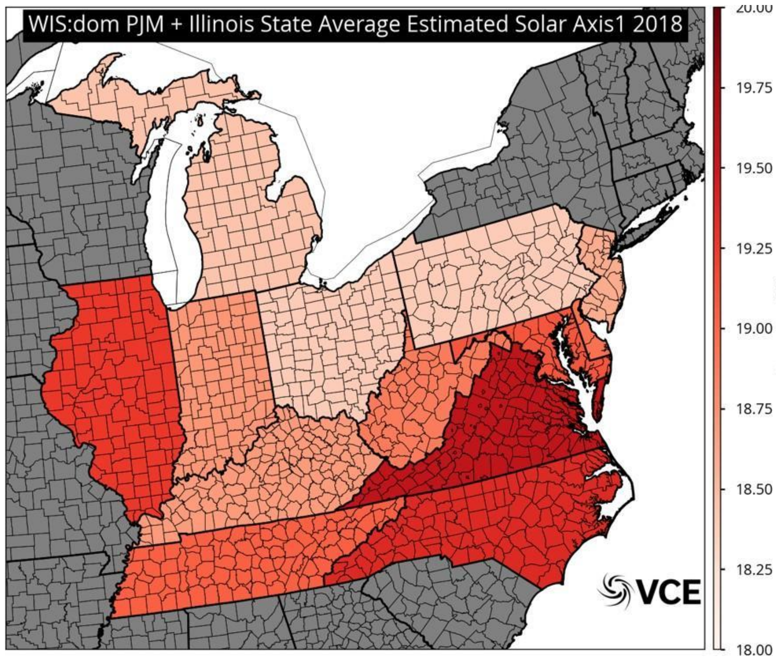

Figure D-56. The average axis-1 solar capacity factor (%) for 2018 by state in PJM.

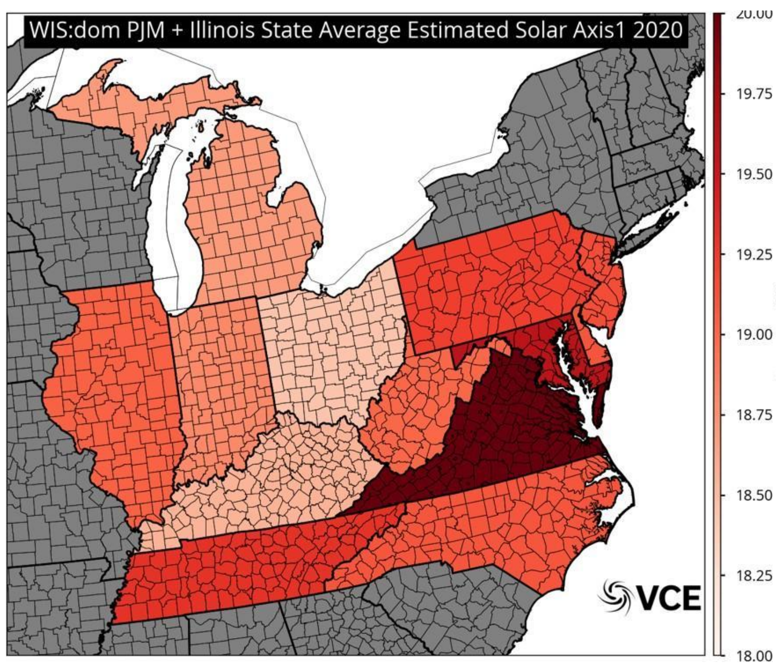

Figure D-57. The average axis-1 solar capacity factor (%) for 2020 by state in PJM.

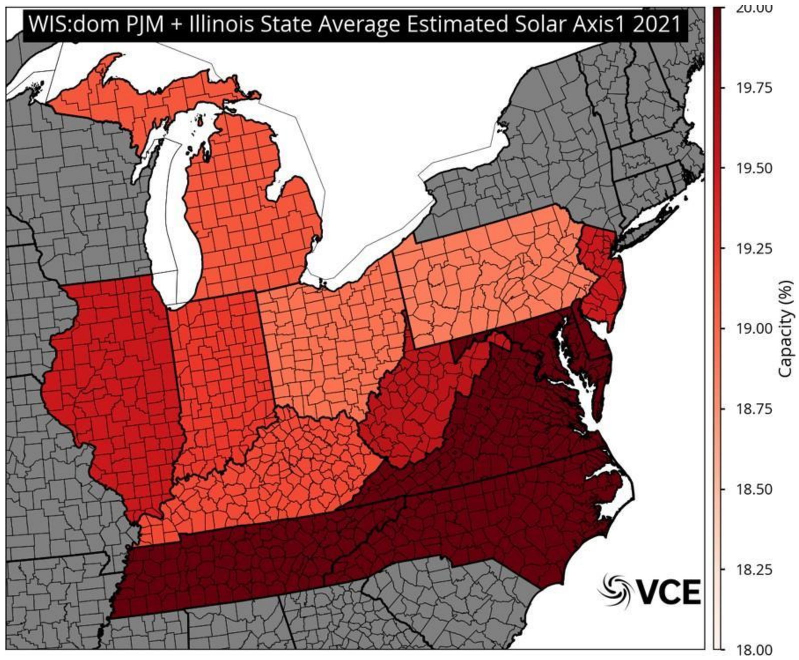

Figure D-58. The average axis-1 solar capacity factor (%) for 2021 by state in PJM.

VCE investigated the wind and solar resources at different temporal granularity as well for the present analysis. This is another way to understand the optimization choices available to WIS:dom-P.

Figure D-59 and **Figure D-60** show the average annual 100-meter onshore wind and axis-1 solar resources throughout every hour of the day for the portion of the states within the domain modeled. These time series are potentially weighted. This means that what is considered in these plots are areas that actually have renewable resource siting potential. Regions like Washington, D.C. have no space to build utility solar and wind. Renewable weather resource in that area will be zero, for instance. This is only shown for 2020 since the main takeaways were similar for other years as well. Maryland, in general, is higher than average regarding both the solar and wind resources across the various regions (states) in the domain. This is more pronounced in the solar resource. Comparing **Figure D-59** and **Figure D-60** shows that on average throughout the day, solar resource is anti-correlated with the wind resource of the region.

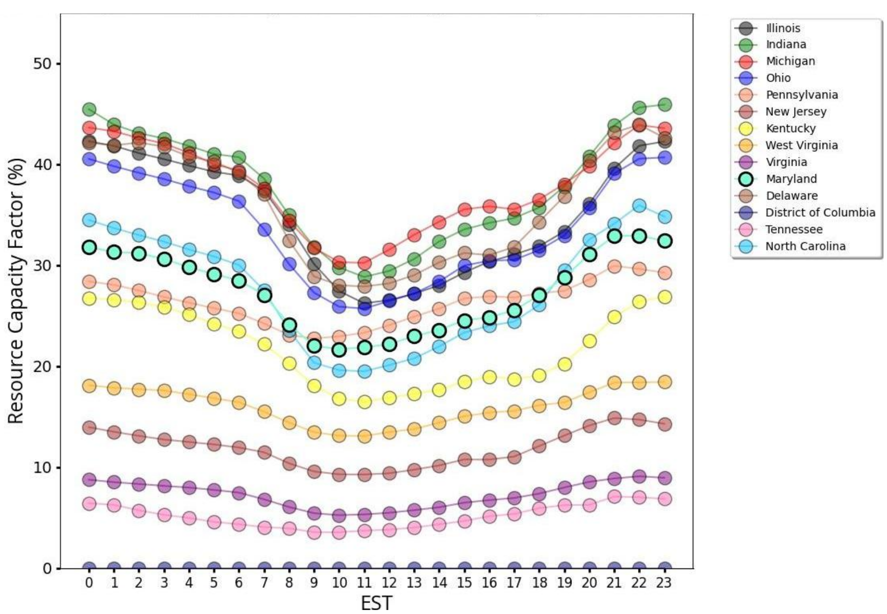

Figure D-59. The 2020 average hourly 100-m wind resource capacity for all states in the modeled domain. For partial domain states, only the portion in the domain is incorporated. Maryland is bolded in aquamarine.

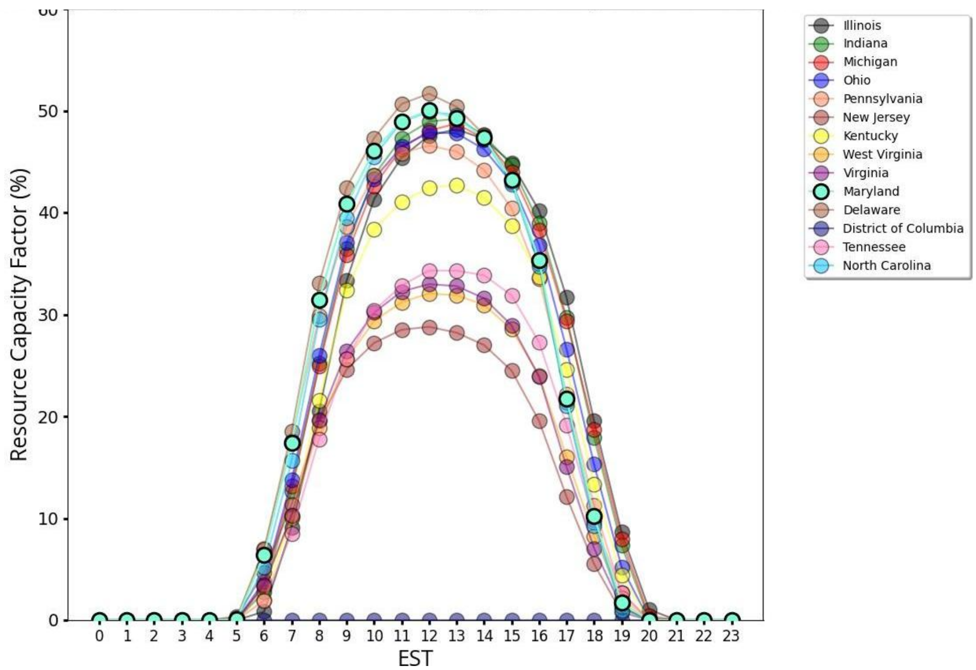

Figure D-60. The 2020 average hourly axis-1 solar resource capacity for all states in the modeled domain. For partial domain states, only the portion in the domain is incorporated. Maryland is bolded in aquamarine.