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Bridging the Gaps: The Impact of Interregional Transmission on Emissions and Reliability

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Audun Botterud, Christopher R. Knittel, John E. Parsons,
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Authors are listed in alphabetical order

Abstract

The substantial decline in the cost of wind and solar generation over recent decades has significantly altered the energy landscape. With these technologies becoming economically viable, even without stringent decarbonization policies, the role of interregional transmission has become increasingly important. This study examines the value of interregional transmission to the U.S. grid under current policies and deep decarbonization scenarios. By utilizing the GenX capacity expansion model, we evaluate the proposed BIG WIRES Act, which mandates a minimum interregional transfer capability requirement. Our analysis focuses on four key areas: interregional transmission builds and grid characteristics, electricity system cost savings, grid reliability during extreme weather events, and climate benefits. Results show that the Act can lead to a 68% increase in interregional transfer capability under current policies, resulting in annual system cost savings of $487 million and a 43.33 Mmt reduction in CO_2 emissions. The benefits are even greater under a 95% CO_2 reduction mandate. The study underscores the importance of interregional transmission in optimizing renewable energy use, enhancing grid reliability, and achieving cost savings and emissions reductions.

Keywords: Interregional Transmission, Capacity Expansion, Electricity Reliability, Greenhouse Gas Emissions

JEL: H23, Q58, L51

**Botterud:* Laboratory for Information and Decision Systems, Massachusetts Institute of Technology, Cambridge, MA, USA. audunb@mit.edu. *Knittel:* Sloan School of Management, Massachusetts Institute of Technology, Cambridge, MA, USA. Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA, USA. MIT Climate Policy Center, Massachusetts Institute of Technology, Cambridge, MA, USA. National Bureau of Economic Research, Cambridge, MA, USA. knittel@mit.edu. *Parsons:* Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA, USA. MIT Climate Policy Center, Massachusetts Institute of Technology, Cambridge, MA, USA. jparsons@mit.edu. *Senga:* Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA, USA. MIT Climate Policy Center, Massachusetts Institute of Technology, Cambridge, MA, USA. jsenga@mit.edu. *Story:* MIT Climate Policy Center, Massachusetts Institute of Technology, Cambridge, MA, USA. dstory@mit.edu.

1 Introduction

One of the dramatic changes to the energy landscape over the last decades has been the substantial decline in the cost of wind and solar generation. Globally, the levelized cost of electricity (LCOE) for wind and solar decreased by 69% and 89%, respectively, from 2010 to 2022 (IRENA, 2022).[1] The US also saw similar trends with construction costs for wind and solar decreasing by 25% and 58% within the same time period (EIA, 2023). New investments in these technologies therefore often make economic sense on their own, even without stringent decarbonization policies. Interregional transmission can be a valuable complementary investment. The endowment of wind and solar resources varies significantly across regions. For example, in the U.S., some of the most attractive wind resources lie in the band of territory running down the center of the country from the Canadian border to west Texas. Much of the southeastern U.S. has relatively less of both wind and solar resources compared to other regions of the country. Interregional transmission enables the exploitation of the best locations to the benefit of the load wherever it may be located. Interregional transmission also diversifies the geographical sourcing of wind and solar generation, which cancels some of the natural variability and minimizes the required investment in balancing capacity. This diversification also improves reliability.

We study the value of interregional transmission to the U.S. grid under current policies and under a policy of deep decarbonization. A variety of studies of optimal grid expansion for deep decarbonization find that substantial interregional transmission capacity lowers system costs (see for example, Brown and Botterud, 2021; Denholm et al., 2022). We show that this is also true for more modest decarbonization scenarios reflecting existing policies and applying a more realistic grid expansion policy.

Although the U.S. is a large, continental economy, transmission planning remains geographically constrained. Primary responsibility lies with one or another regional authority, whether it be an independent system operator (ISO), a regional transmission organization (RTO), or some other balancing authority (BA). These have the mission and protocols to develop transmission projects within their geographic boundaries and are less able to develop interregional projects. Joskow (2021) details the situation.

To address this challenge, the BIG WIRES Act (S.2827 - 118th Congress) was proposed in the US Congress and would require transmission planning regions to achieve minimum interregional transfer capability requirements. The bill requires that each FERC Order No. 1000 region should have the ability to transfer at least 30% of its coincident peak load to neighboring regions by 2035 (Hickenlooper and Peters, 2023). The intent is to incentivize coordination among the regions and thereby capture the cost, reliability, and climate benefits of interregional transmission. A distinctive feature of the bill is its establishment of a common minimum transfer capability requirement for regions without specifying where each region should connect. This leaves the siting and connection decisions to each region. The BIG WIRES Act, therefore, reflects a policy-driven path to interconnecting the US. In this paper, we analyze the BIG WIRES Act as our way of more realistically showing the impact of interregional transmission.

We use the capacity expansion model GenX to evaluate the BIG WIRES Act in four ar-

[1] The global weighted average LCOE of solar was \$0.445/kWh in 2010 and was \$0.049/kWh in 2022. The global weighted average LCOE of onshore wind was \$0.107/kWh in 2010 and was \$0.033/kWh in 2022.

eas: (1) interregional transmission builds and grid characteristics, (2) electricity system cost savings, (3) grid reliability to extreme weather events, and (4) climate benefits. We first assess the impact under current policies, with no further mandate for CO_2 emission reductions—the "Current Policies" case. As a point of comparison, we also assess how the impact changes with the imposition of a mandate to reduce emissions 95% relative to 2005 levels—the "95% CO_2 reduction" case. The BIG WIRES Act only mandates a minimum transfer capacity without specifying which interregional links be built, so we develop the Greedy Dual Algorithm to locate the minimum builds. It iteratively increases transmission between GenX zones proportionally based on the dual of the transmission constraint. To assess the impact on reliability during extreme weather events, we use a Monte Carlo simulation to generate a sample distribution of randomly selected sets of generators that go offline. We use the GenX dispatch model with this reduced capacity to evaluate non-served energy in each draw of the distribution, and we report the full sample outcomes.

Under current policies, we find that the Act produces a 68% increase in interregional transfer capability. Most of the new transmission builds are concentrated in the Midwest, Mid-Atlantic, and Southeast regions. Certain regions then become net exporters (Central, Midwest, Mid-Atlantic) and others become net importers (Southeast and Southwest).

The BIG WIRES Act leads to annual system cost savings of $487 million. These savings arise because interregional transmission flows substitute for capital investments in thermal generators needed to balance the intermittency of renewables in unconnected regions. There is also a spatial shift of where renewables get built – from regions with relatively low VRE capacity factors to those with high capacity factors, which reduces the amount of investment needed to produce the same amount of generation.

The minimum interregional transfer capability requirements lead to lower average outages in most regions. More interregional transmission allows regions to import from its neighbors during extreme weather events. However, the Southwest region, absent a countervailing constrain, takes advantage of the additional transmission to reduce its local generation capacity, which exposes the region to reliability problems during extreme weather events.

Under current policies, expanded interregional transmission reduces CO_2 emissions by 43.33 Mmt. This is primarily due to the expanded use of renewables. Of particular note, the Southeast region, which has relatively poor quality wind and solar resources, can take advantage of the transmission to exploit high quality renewables in other regions.

All of these benefits arise under current policies. Consistent with other studies, we also find higher benefits with deeper decarbonization. In the 95% CO_2 reduction case, the BIG WIRES Act produces an additional 15% increase in interregional transfer capability, for a total increase over current capability of 83%. This produces annual system cost savings of $3.21 billion.

The paper is organized as follows: In the rest of this section, we provide a brief review of related literature. We then give an overview of the data and methodology in section 2. Our main results on transmission builds, cost, reliability, and climate follow in Section 3. The extensions on other policies and alternative minimum requirement calculations are in section 4. Finally, we discuss the policy implications and conclude our paper in section 5.

1.1 Related Literature

Several studies have looked at the role and value of interregional transmission in the US grid using capacity expansion models. Gagnon et al. (2023) and Denholm et al. (2022) both show that large transmission build-outs across the US become a key feature across a wide range of possible future scenarios including among others: the availability of direct air capture technology, cost and demand assumptions, and land use constraints for wind and solar resources. Bloom et al.'s (2022) *interconnection seams study* show that increasing HVDC capacity between the eastern and western interconnect reports high benefit-to-cost ratios. The benefit comes from being able to use VRE resources across the separate grids' seams – a consistent conclusion across transmission studies both in the US (ours included) and in other countries (Becker et al., 2014; Rodríguez et al., 2014; Brown et al., 2018; Dimanchev et al., 2021). Shi (2023) combined capacity and transmission expansion with optimization of the hydrogen supply chain and bioenergy with carbon capture and sequestration (BECCS). She found that transmission becomes key to achieving deep decarbonization in the US as it enables access to VRE resources used for electrolyzers. However, consistent with existing studies, sector-coupling (in this case with BECCS) diminishes the cost benefits of transmission (Becker et al., 2014).

The closest to our study is the work done by Brown and Botterud (2021). They use a capacity expansion model with detailed spatial and temporal resolution to show that in a deeply decarbonized US grid, more interregional transmission leads to lower system costs. However, they assume a so-called green field in their modeling scenarios, i.e. existing infrastructure is ignored. In our case, we provide a more realistic brownfield model and look at the US system's evolution into 2035. Other studies are less optimistic about the value of transmission. Jayadev et al. (2020) discuss that system emissions and cost only minimally decrease with more transmission builds. The Inflation Reduction Act (IRA) of 2021, which we include in our work, was not yet implemented during their study. The IRA production tax credits further lower the generation cost of wind and PV, which could have increased the impact of transmission by connecting load centers to renewable resources. Zheng et al., (2024) reached a conclusion that transmission has minimal impact on *wholesale cost of power*. They define the wholesale cost of power as the load-weighted dual of the load-serving constraint. It is the slight lowering of this metric with more transmission that leads them to their conclusion. Using this metric on our results leads to similar limited decreases, but the annual total system cost savings we obtain is in the order of \$487 million to \$3.21 billion. This is a relatively small percentage of total system cost but still large in absolute, annualized terms.

In all of the transmission studies mentioned, transmission is built optimally between model regions without limitation. That is, if the modeling scenario allows for transmission to be built, there is no maximum line reinforcement constraint on them. When this is the case in cost-optimizing models, it is not surprising that large transmission builds are observed. It is unlikely, however, for this to occur in practice. Our work provides a more realistic, policy-driven analysis. We only allow enough interregional transmission to be built to meet minimum interregional transfer requirements. To the best of our knowledge, ours is the first study taking this approach. This distinction is key because we model a more realistic setting of regions facing barriers to building interregional transmission (DOE, 2023; Hausman, 2024).

2 Data and Methodology

2.1 GenX: Capacity Expansion Model

The analysis uses the open-source capacity expansion modeling software GenX developed at the MIT Energy Initiative and presently maintained by a team from MIT, Princeton, and NYU (Jenkins and Sepulveda, 2017). GenX is a least-cost mixed integer linear programming (MILP) model that co-optimizes generation and transmission investments and dispatch decisions among pre-defined zones within the power system. The optimization accounts for capital, operational, and fuel costs, generator technical operating characteristics, capacity factors for renewables, and demand information. The objective is to minimize annual system cost, which is the sum of investment in generation and storage, fixed and variable operating and maintenance costs, new transmission investment costs, fuel and startup costs, as well as tax credits and other incentives, if any. GenX assumes a representative year of operation and perfect foresight of hourly demand and capacity factor data for renewables supply in its dispatch decisions.

2.2 Input Data

We source input data from Shi (2023) and PowerGenome (Schivley, 2023) which is a data processing software that aggregates data from publicly available sources such as NREL's ATB for cost data (Vimmerstedt et al., 2022), NREL's EFS for demand data (Mai et al., 2018; Mai et al., 2020), and EIA's Form-860 (EIA, 2022) for existing generator data.

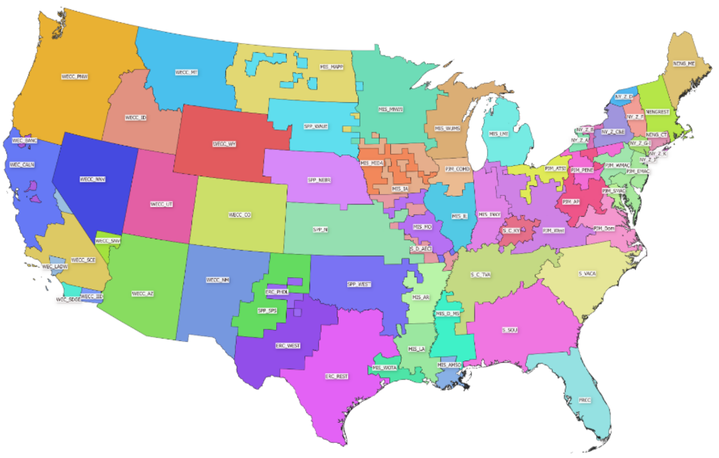
2.2.1 Zones and Transmission Network

The first step to modeling the BIG WIRES Act within GenX is representing the 11 FERC Order No. 1000 transmission planning regions. To do so, we adapt Shi (2023). Shi (2023) creates 64 zones within the continental US within GenX, shown in Figure 1a.[2] Each zone $z = 1, 2, \ldots 64$ is grouped into regions represented by the sets Z_r, $r = 1, \ldots, 11$ (Figure 1b) to best mimic the FERC transmission planning regions and Texas (Figure 1c). Note that we group zones into regions but retain the granularity of the model at the zonal level. This allows us to examine the interactive effects of building transmission within and between regions.

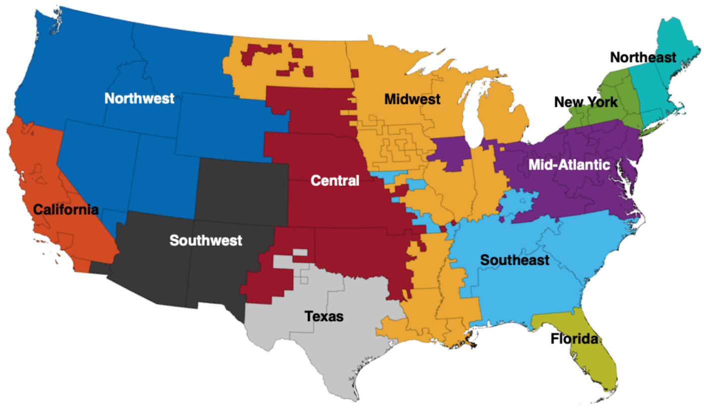
Currently, there is no consistent methodology for determining what the transfer capability is between two zones and regions. In 2006, the North American Electric Reliability Corporation (NERC) required each reliability coordinator and planning authority to provide methodologies for determining transfer capability (NERC, 2006).[3] Inevitably, although regularly updated, these methodologies varied from region to region and usually required complex simulations (see, for example, CAISO (CAISO, 2024) and PJM's (PJM, 2024) methodologies). To address these differences, NERC more recently initiated a nation-wide Interregional Transfer Capability Study (ITCS) that quantifies transfer capability between regions with the hope that it unifies the varying definitions (NERC, 2024). This study is set to be completed by December 2024. The BIG WIRES Act proposes that transfer capability should be the actual observed maximum

[2] The 64 zones are based on the EPA's IPM Regions and the grouping is done to mimic the FERC Order No. 1000 transmission planning regions as close as possible (EPA, 2022; FERC, 2011)

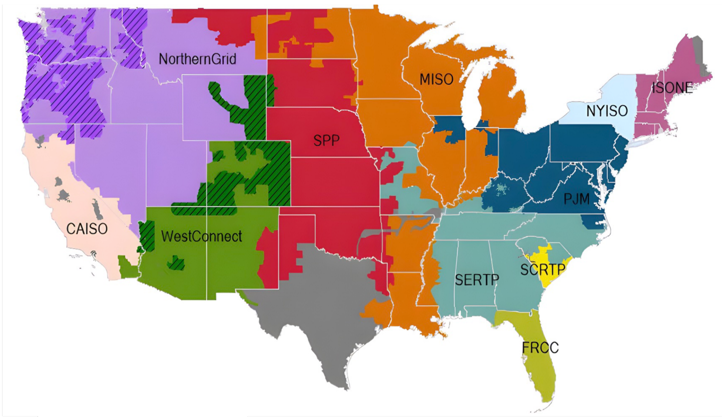
[3] Transfer Capabilities are also sometimes called transfer capacities or transmission capabilities.



(a) 64 Zone Map



(b) 11 Model Region Map created by aggregating the 64 zones



(c) FERC Order No 1000 Transmission Planning Regions

Figure 1: Zonal and Regional Maps

flow between two zones rather than the combined transmission line ratings.[4] In our study, transfer capabilities between two zones are obtained from the EPA's Power Sector Modeling platform which sourced transmission capacities between zones from market reports and regional transmission plans (EPA, 2022). The EPA's transfer capabilities between zones are Firm Total Transfer Capabilities (TTCs), which is the amount of power that can be reliably transferred

[4]The full definition for transfer capability in the BIG WIRES Act is described in section 2.3

if one component of the network goes offline (what is called the "N-1 condition"). We deviate from the definition provided in the BIG WIRES Act because we find it difficult to use historical flow data to determine future transfers, especially as the grid evolves in its capacity mix, load profiles, and resulting transmission flows. Furthermore, the EPA's transfer capabilities have been used to guide regulation for more than four decades (EPA, 2022).[5]

In our model, the EPA transfer capability between two zones z and z' (where $z \neq z'$) is represented by a non-negative number $c_{zz'}$ that constrains the maximum amount of electricity that can flow between zones. The combination of zones z and z' where there is existing or where we allow potentially new built transfer capability is the number of possible *lines* L. We then have $L = 142$, with each line represented by a line number $l = 1, 2, \ldots, L$.[6] The origin zone of line l is $l_o = z$ and the destination zone is $l_d = z'$. Transmission lines between zones within the same region are called *intraregional*, and transmission lines between zones from different regions are *interregional*.[7] That is, l is intraregional if $l_o, l_d \in Z_r$ for the same r and interregional otherwise. Note that $c_{zz'} = c_{z'z}$ and both are denoted by the same l. We can also then define the capacity of line l as $\hat{c}_l = c_{zz'}$. Given these definitions, the transfer capability $TC_{rr'}$ between regions r and r' is the sum of transfer capabilities between zones located in r and r'. More specifically:

$$TC_{rr'} = \sum_{l \in \mathcal{L}_{rr'}} \hat{c}_l, \tag{1}$$

where $\mathcal{L}_{rr'} = \{l | l_o = z \in Z_r; l_d = z' \in Z_{r'}\}$ is the set of lines where the origin zone z is in region r and the destination zone z' is in region r'. The overall interregional transfer capability $\hat{TC}_r$ of a region r is the sum of its transfer capability to all other regions:

$$\hat{TC}_r = \sum_{\forall r' \neq r} TC_{rr'}. \tag{2}$$

It will also be convenient for later calculations to define $\hat{\mathcal{L}}_r = \bigcup_{\forall r'} \mathcal{L}_{rr'}$ which is the set of all interregional lines of region r (i.e., the union of the sets of lines that connect from region r to another region r'). Table 1 shows the number of zones per region and the current interregional and intraregional transfer capabilities. Table 6a shows the current interregional transfer capability between regional corridors.

When expanding the capacity of existing interregional and intraregional transmission, we incur a transmission investment cost. The costs are line-dependent and are based on NREL REeDS and the Phase II Eastern Interconnection Planning Collaborative (EIPC) report estimates (Shi, 2023; Ho et al., 2021; EIPC, 2015). A detailed methodology for calculating the transmission investment costs can be found in Appendix A.

[5] Some examples of these regulations are the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants (EPA, 2023c), (2) Good Neighbor Plan for 2015 Ozone NAAQS (EPA, 2019), and the Affordable Clean Energy Rule (EPA, 2023a).

[6] Line transfer capability between zones can be found in Table 13 in the Appendix.

[7] Another type of transmission that can be built is transmission lines within each zone. We call these *intrazonal* transmission lines but do not model them explicitly. The cost of lines that connect new generators to the grid is also not included explicitly, but the cost is embedded in the investment in new generators

Table 1: Zones and Transfer Capability per Region

Region	Number of Zones	Transfer Capability (in GW)	
		Intraregional (TC_{rr})	Interregional ($\hat{TC}_r$)
California	5	11.45	19.08
Florida	1	0.00	3.60
Northeast	3	4.95	2.16
Midwest	14	19.02	35.92
Northwest	7	10.49	22.17
New York	8	19.62	4.08
Mid-Atlantic	9	39.18	24.01
Southeast	5	5.58	23.32
Central	5	7.53	10.42
Southwest	4	3.27	12.40
Texas	3	8.86	0.82

2.2.2 Available Technology

Our model includes existing capacity generators as well as a set of new technologies that can be deployed. Existing generation capacity is sourced from EIA Form-860 and aggregated through PowerGenome (Schivley, 2023). Table 2 summarizes the existing generating capacity per transmission planning region. We assume that there is a second-license extension for nuclear generators because of the passage of the Inflation Reduction Act (Gagnon et al., 2023).

Table 2: 2022 Existing Generating Capacity per Region (in GW)

	California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	Total
Batteries	11.33	0.23	0.54	0.34	0.08	0.20	0.36	1.08	0.44	1.28	4.40	20.28
Conventional Hydroelectric	8.86	4.58	0.04	2.83	1.42	3.63	1.08	35.14	11.04	3.24	0.48	72.35
Conventional Steam Coal	0.06	20.24	4.87	41.93	50.41	-	0.53	13.72	43.36	8.30	13.63	197.05
Hydroelectric Pumped Storage	3.94	0.47	-	5.21	2.49	1.41	1.80	0.31	6.41	0.80	-	22.84
Natural Gas Combined Cycle	21.18	12.21	37.54	60.94	39.01	12.32	16.03	15.85	44.70	15.72	41.75	317.25
Natural Gas Combustion Turbine	11.56	11.27	9.23	30.92	27.90	3.98	2.02	4.12	32.72	7.90	11.16	152.78
Natural Gas Steam Turbine	4.62	10.38	4.63	10.20	14.05	9.83	1.44	0.84	4.42	2.28	11.22	73.90
Nuclear	2.24	2.03	3.74	33.46	11.90	3.38	3.35	1.17	28.71	4.00	5.12	99.09
Offshore Wind Turbine	-	-	-	-	-	-	0.03	-	-	-	-	0.03
Onshore Wind Turbine	6.04	35.54	-	10.43	32.51	3.39	1.55	16.76	1.45	9.42	34.05	151.14
Small Hydroelectric	0.32	0.10	-	0.30	0.78	0.60	0.41	0.79	0.20	0.14	0.02	3.68
Solar Photovoltaic	19.89	0.81	9.45	11.10	9.48	1.87	2.65	9.79	16.42	8.58	20.83	110.88
	90.05	97.86	70.04	207.68	190.03	40.61	31.25	99.58	189.85	61.66	142.67	1,221.26

Fixed O&M costs for new capacity are sourced from NREL's Annual Technology Baseline (ATB) 2022 for the basis year 2035 assuming the moderate cost case and a market financial scenario except for Natural Gas with CCS for which we assume the conservative cost case (Vimmerstedt et al., 2022). CAPEX and WACC are taken as average values from NREL ATB 2022 from the years 2023 to 2035. Meanwhile, cost assumptions for existing plants use the basis year 2020, with variation assumptions from PowerGenome depending on the start year of operation. State-level offshore wind mandates as well as production and tax credits associated with the Inflation Reduction Act are also implemented in the model (Ho et al., 2021; Gagnon et al., 2023). Investment, operating, and maintenance costs for new generators can be found in Table 3. Fuel costs are sourced from EIA's AEO, with details in Appendix B.

Table 3: New Technology Investment and Operation Costs in 2035

	Capex ($/MW)	Capital Recovery Period (years)	WACC	Investment Cost ($/MW-yr)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
Natural Gas Combined Cycle	919,930	15	3.56%	80,609	28,000	2.00
Natural Gas Combined Cycle with CCS	2,292,360	20	3.56%	163,185	67,000	6.00
Natural Gas Combustion Turbine	792,572	15	3.56%	69,449	21,000	5.00
Nuclear	6,964,382	40	3.29%	318,166	145,960	2.84
Solar Photovoltaic	844,746	20	2.50%	54,330	14,721	-
Onshore Wind Turbine	1,052,987	20	3.06%	71,488	37,489	-
Offshore Wind Turbine	3,890,946	20	4.24%	294,739	61,370	-
Battery	252,126	15	2.50%	20,405	6,303	0.15

2.2.3 Demand and Supply Curves

Load is sourced from NREL's EFS (Mai et al., 2018) through PowerGenome (Schivley, 2023) where we assume a high electrification scenario with moderate technology advancement. Total system load growth is 23.5% from 4,082 TWh in 2022 to 5,042 TWh in 2035. The load duration curves for each region can be found in Figure 2. The total regional load is indicated in the Figure. The three regions with the highest total load are the Mid-Atlantic region at 20% of total load, followed by the Midwest at 16% and Northwest at 8%.

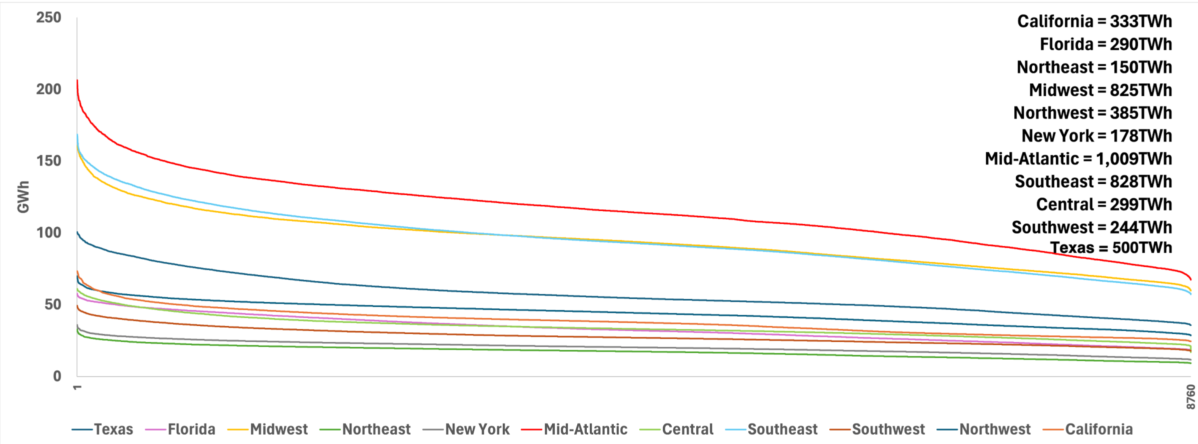


Figure 2: Regional Load Curves ordered from highest to lowest

Solar and Wind Capacity Factors were obtained from Shi (2023), who follow the methodology provided by Brown and Botterud (2021). The capacity factors are processed from NREL's National Solar Radiation Database and the WIND Toolkit.

Due to the large scale of the optimization problem with 64 zones and more than 1000 generator clusters, we use a procedure called *Time Domain Reduction* (TDR). TDR creates a subset of representative periods for the operation of an entire year. GenX has a built-in TDR procedure that uses k-means clustering to determine the subset. A less computationally intensive dispatch model where we take the generation and transmission investments resulting from the TDR expansion case as input and do not allow any new investments in generation capacity (i.e., one where only dispatch decisions are made) was tested for a full year. We found that operational costs and dispatch results in this model were similar to the TDR case.

2.3 The BIG WIRES Act

In this section, we discuss the details of the BIG WIRES Act and how it is represented in our model. The BIG WIRES Act specifies that each FERC Order No. 1000 region should achieve a Minimum Interregional Transfer Capability (MITC). The MITC is calculated as the minimum between 30% of regional coincident peak load and 15% of regional coincident peak load plus the current transfer capability. The requirement is designed to give regions with lower current transfer capability relative to its peak load a lower MITC than regions with higher current transfer capabilities. The 30% value is what we call the MITC % represented by the variable p. We generalize this calculation for varying p using the following formula:

$$MITC_r(p) = \min(p\bar{D}_r, \frac{p}{2}\bar{D}_r + \hat{TC}_r), \tag{3}$$

where $\bar{D}_r$ is the coincident peak load. It is straightforward to see that the BIG WIRES Act specifies $p = 30\%$. The MITC formula in (3) relies on two values: the coincident peak load of a region and its current transfer capability. The BIG WIRES Act defines the coincident peak load of a region as the 99.9$^{\text{th}}$ percentile of the combined hourly load of all zones within a region. The current transfer capability is defined as the maximum between the absolute values of a region's coincident import and export capability – 0.01$^{\text{th}}$ and 99.9$^{\text{th}}$ percentile, respectively, of the coincident hourly electricity flows of a region to other regions.

For the purposes of this analysis, we keep the definition of peak load but use the EPA's transfer capability (specified in section 2.2.1) as an alternative to the BIG WIRES Act's definition. We extend our analysis to the case where we account for the flows as a measure of transfer capability in section 4. Table 4 shows the calculation for MITC across different p values. Note that the BIG WIRES Act does not include Texas.

Table 4: Minimum Interregional Transfer Capability values per MITC % (in GW)

			MITC									
Region	Peak Load	Current Transfer Capability	p =10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
California	70.93	19.08	7.09	14.19	21.28	28.37	35.47	40.36	43.91	47.46	51.00	54.55
Florida	55.80	3.60	5.58	9.18	11.97	14.76	17.55	20.34	23.13	25.92	28.71	31.50
Northeast	30.47	2.16	3.05	5.21	6.73	8.25	9.78	11.30	12.82	14.35	15.87	17.39
Midwest	157.51	35.92	15.75	31.50	47.25	63.00	75.30	83.18	91.05	98.93	106.80	114.68
Northwest	65.75	22.17	6.57	13.15	19.72	26.30	32.87	39.45	45.18	48.46	51.75	55.04
New York	33.64	4.08	3.36	6.73	9.12	10.80	12.49	14.17	15.85	17.53	19.21	20.90
Mid-Atlantic	195.35	24.01	19.53	39.07	53.32	63.08	72.85	82.62	92.39	102.15	111.92	121.69
Southeast	160.27	23.32	16.03	32.05	47.36	55.38	63.39	71.40	79.42	87.43	95.44	103.46
Central	59.67	10.42	5.97	11.93	17.90	22.36	25.34	28.32	31.31	34.29	37.27	40.26
Southwest	47.17	12.40	4.72	9.43	14.15	18.87	23.58	26.55	28.91	31.27	33.62	35.98

2.4 Modeling Scenarios

Now that we have provided details of our model, we turn to a discussion of the modeling scenarios. Our evaluation compares two systems: one where we impose an MITC constraint and another where there is no MITC. These two systems represent the cases where the BIG WIRES Act is and is not implemented. We call these the "BWA" and "No BWA" scenarios, respectively. We assume that No BWA (i.e., not implementing the BIG WIRES Act) leads to no new interregional transmission being built. We also assume that in BWA, only enough new interregional transmission to satisfy the MITC requirements will be built. In both scenarios, new intraregional transmission can be built within each zone. This mimics the inclination of zones being better able to site transmission within their own transmission-planning region while facing barriers to building interregional transmission.

The constraints to only allow building of new interregional transmission to meet the MITC requirement are chosen according to a procedure called the *Greedy Dual Algorithm* and is discussed in section 2.4.1. Unless otherwise stated, the analysis and comparison between scenarios is such that BWA has an MITC % of $p = 30\%$, while No BWA has an MITC % of $p = 0\%$. We also examine two future decarbonization scenarios, namely, one without any CO_2 emissions reduction target and another with a 95% CO_2 emissions reduction target relative to 2005 levels – what we call the "Current Policies" and "95% CO_2 reduction" scenarios.[8] These two scenarios illustrate how the BIG WIRES Act interacts with decarbonization policies that may be implemented. As part of the analysis, scenarios that are characterized by varying p values are included in each section, where appropriate. Evaluating across this sensitivity provides us with crucial analysis on proper implementation levels of the BIG WIRES Act. The systems are all examined for the year 2035.

2.4.1 Greedy Dual Algorithm

Within GenX, additional transfer capability can be built between two zones up to a set maximum value R_l for transmission line l.[9] In the No BWA scenario, R_l is set to 0 for all lines that connect zones located in different regions (i.e., $R_l = 0$ if $l_o \neq l_d$; consistent with the definition of the No BWA scenario). To satisfy the MITC requirement in the BWA scenario, R_l should be greater than 0 for some but not all interregional lines. That is, the maximum increase in transfer capability should be high enough such that the MITC requirements are met. However, since GenX is a cost optimization model, allowing $R_l > 0$ for all lines results in the model possibly building more than what the BWA requires. Maintaining our assumption that only enough transmission is built to satisfy the MITC requirement for each region necessitates a procedure to determine what R_l should be. The Greedy Dual Algorithm addresses this.

The Greedy Dual Algorithm is a procedure that increases R_l for all lines connected to a region proportional to the dual of each transmission constraint. This is done until MITC requirements for all regions can be met. Increasing R_l proportionally at the line with the *most negative dual* reflects a system cost optimizing preference that is consistent with the objective function of GenX. More concretely, the procedure is as follows:

Algorithm 1. *Greedy Dual Algorithm*

Let δ_r *be the gap between the MITC of the region* r *and the model's current ability to meet the requirement. It is initialized as* $\delta_r = MITC_r - \sum_{l \in \hat{\mathcal{L}}_r} (\hat{c}_l + R_l)$ *for all* r*. Define the dual of the transmission constraint on line* l *in model no BWA as* d_l*.*

1. *Obtain* $\delta_r^* = \max\{\delta_r\}$

[8] We do not account for future state or local regulations in the reduction targets and only impose a system-wide CO_2 constraint.

[9] R is used because adding transfer capability is also called "reinforcing" transmission.

2. *Set* $R'_l = R_l + \frac{|d_l|\delta^*_r}{\sum_{l\in\hat{\mathcal{L}}_r}|d_l|}$ *for each* $l \in \hat{\mathcal{L}}_r$

3. *Set* $R_l = R'_l$ *for each* $l \in \hat{\mathcal{L}}_r$

4. *Recalculate* $\delta_r = MITC_r - \sum_{l\in\hat{\mathcal{L}}_r}(\hat{c}_l + R_l)$ *for all* r

5. *If* $\exists\delta_r > 0$*, go back to step 1. Otherwise, stop.*

We note that the greedy dual algorithm can lead to non-cost optimal transmission build outs. This is because dual values change at every increment of the right-hand side in a linear programming model, but the algorithm makes the maximum line reinforcements increase simultaneously. To get the cost-optimal build-outs, an iterative dual procedure can be used that increases R_l for the line with the most negative dual by a small amount, one line at a time. The optimization problem is then re-evaluated with the slightly larger R_l, and the procedure is repeated until all MITC requirements are met. We call this the *Iterative Dual Algorithm.* It is computationally intensive because of the re-evaluation that happens at each iteration. Implementation of the algorithm can be found in the Supplemental Material. Comparing the two approaches, the greedy dual algorithm reflects regions' strategic decisions to simultaneously build transmission given economic signals (i.e., the duals). On the other hand, the iterative dual algorithm assumes regions have perfect information on the impact of transmission builds between regions. This unrealistic assumption and the computational complexity shifted our preference to the greedy dual algorithm.

2.5 Extreme Event Simulation Methodology

We also create a stylized methodology using Monte Carlo simulation to analyze a power system's reliability during extreme weather events. We assume that an extreme weather event manifests in the form of simultaneous random generation capacity outages over a specified time period. That is, we model an extreme weather event's impact on a power system as a $q_{y,r}$ percentage of capacity outages for technology type y at region r.[10]

The aim is to create a distribution of the region's average non-served energy during extreme weather events and obtain the overall average non-served energy across the entire distribution. This distribution is obtained by repeatedly simulating random generator outages in the region. In each simulation iteration, outages are assigned based on uniform, random draws from the set of eligible generators. The capacity of this generator is reduced by a set percentage, and the process is repeated until the specified total capacity experiencing an outage is met. This process is rigorously illustrated using the following heuristic:

Algorithm 2. ***Generator Outage Allocation Algorithm***

Let $\hat{C}_{y,r}$ *be the total capacity of technology* y *that experiences an extreme weather event outage in region* r*. It is calculated as* $\hat{C}_{y,r} = a_{y,r}q_{y,r}$ *where* $a_{y,r}$ *is the total generation capacity of* y *in* r*. In the heuristic, this will also be used to track the amount of capacity outages that has already been allocated to generators. Let* $\mathcal{G}_{y,r}$ *be the set of all generator units of type* y *found*

[10] In our experiments, we assume that outages occur in a region, but the methodology can be easily adjusted to apply to zones (i.e. instead of $q_{y,r}$ the percentage of outages will be $q_{y,z}$, where z is a zone.

in r. This set contains unique generator IDs, g. Let $\psi \in (0,1)$ be a fixed capacity percentage that remains from a chosen generator. Finally, let C_g be the remaining, unaffected capacity of generator g. It is initialized as the existing capacity of g.

1. *If $\hat{C}_{y,r} > 0$, proceed to Step 2. Otherwise, stop.*
2. *Draw a generator $g \in \mathcal{G}_{y,r}$ according to a uniform distribution.*
3. *Set $C'_g = \min(\psi C_g, \hat{C}_{y,r})$ and $\hat{C}'_{y,r} = \hat{C}_{y,r} - (C'_g - \min(\psi C_g, \hat{C}_{y,r}))$*
4. *Set $C_g = C'_g$ and $\hat{C}_{y,r} = \hat{C}'_{y,r}$. If $C_g = 0$, remove g from $\mathcal{G}_{y,r}$ (i.e. $\mathcal{G}_{y,r} = \mathcal{G}_{y,r}/\{g\}$). Go back to Step 1.*

The output of an iteration i of Algorithm 2 is a set $\mathcal{C}_{y,r,i} = \{(g, C_g)|g \in \mathcal{G}_{y,r}\}$ where each element is a vector of the generator and its remaining capacity. C_g replaces the original capacity for g in GenX. A dispatch model over a specified time interval denoted by $\mathcal{T} = [t^{\text{start}}, t^{\text{end}}]$ is then run, where t^{start} and t^{end} denote the start and end hours of the extreme event simulation. We calculate the mean of the non-served energy $N\bar{S}E_i$ resulting from this dispatch model as $N\bar{S}E_i = \frac{\sum_{t\in\mathcal{T}} NSE_{t,i}}{t^{\text{end}} - t^{\text{start}} + 1}$, where $NSE_{t,i}$ is the non-served energy in t at iteration i. Algorithm 2 is then repeated across an I number of iterations and the overall average non-served energy is calculated as $N\bar{\bar{S}}E = \frac{N\bar{S}E_i}{I}$.

2.6 Model Limitations

Before proceeding with the results and analysis, we discuss and reiterate some important limitations of our model. First, the model specifies total system cost-optimized results where one centralized agent is assumed to make the investment and dispatch decisions. We also assume a pipeline flow model of transmission between zones. The difference between AC and DC lines, as well as optimal AC power flows between zones and on individual lines, are not accounted for. This simplification is done to model the national impacts of transmission policy. The stochastic variability of VRE and load is also not considered by assuming exogenous, deterministic time series inputs. Moreover, we do not account for the permitting process in transmission buildouts as well as the time it takes to build transmission infrastructure. Finally, the greedy dual algorithm is just one way of determining the transmission builds between regions. We use the dual of the transmission constraints – a way to lead to system cost optimality – as a basis for the transmission builds. Actual siting and decision-making nuances for each region will lead to variations in reality. The model can be interpreted as a stylized and somewhat idealistic state of the US electric grid in 2035. Despite the limitations, the results obtained through this model provide insights into the impact of building more transmission when it is done through imposing minimum interregional transfer capability requirements, as dictated by the BIG WIRES Act.

3 Results and Analysis

3.1 Transmission Results

3.1.1 Transmission Builds

The first set of analyses concerns where additional interregional transmission gets built and how much transmission each region will have to add to meet the BIG WIRES Act's MITC requirements. Table 5 shows the current interregional transfer capability for each region, the MITC requirement, and the additional transfer capability that each region will build. We also provide a calculation for the MITC requirement and the Total Interregional transfer capability as a percentage of peak load ($\frac{MITC_r}{\bar{D}_r}$ and $\frac{\text{Total}}{\bar{D}_r}$). First, the initial calculations for regional MITC indicate that the Florida, Northeast, New York, and Mid-Atlantic regions are not required to build up to 30% of peak load. This is because for reach region, its current transfer capability is low relative to its peak load. The observation shows the design of the MITC calculation in (3), which makes regions that have less interregional transfer capability start at a lower requirement level.

As we look at the transmission builds following the MITC calculation, we also observe that the Midwest, Northwest, New York, Southeast, and the Southwest each builds beyond its MITC to satisfy the requirements of neighboring regions (i.e., $\frac{\text{Total}}{\bar{D}_r} > \frac{MITC_r}{\bar{D}_r}$ in Table 5). To illustrate an example of why this happens, we look at Florida. Florida is connected to only one other region – Southeast. Therefore, whatever the MITC requirement is for Florida, Southeast may be obligated to build more transfer capability than what its own MITC requires to satisfy Florida's requirements. This result suggests that having one MITC % value for all regions does not mean that all regions will build up to the MITC. Interregional transmission – by definition – requires two regions, and so building more capacity across a corridor results in adding transfer capability to two regions. As we have stated and illustrated, there will inevitably be cases where regions will have to overbuild. MITC requirements are, therefore, effective in inducing more transmission builds than what is prescribed for each region.

Table 5: Current and additional interregional transfer capability per region in the Current Policies setting (GW)

	Peak Load ($\bar{D}_r$)	Current Transfer Capability ($\hat{TC}_r$)	$MITC_r$	$\frac{MITC_r}{\bar{D}_r}$	Additional	Total[11]	% Increase	$\frac{\text{Total}}{\bar{D}_r}$
California	70.93	19.08	21.28	30%	1.98	21.07	10%	30%
Florida	55.80	3.60	11.97	21%	8.25	11.85	229%	21%
Northeast	30.47	2.16	6.73	22%	4.50	6.66	208%	22%
Midwest	157.51	35.92	47.25	30%	13.39	49.31	37%	31%
Northwest	65.75	22.17	19.72	30%	1.73	23.90	8%	36%
New York	33.64	4.08	9.12	27%	8.84	12.92	217%	38%
Mid-Atlantic	195.35	24.01	53.32	27%	28.77	52.78	120%	27%
Southeast	160.27	23.32	47.36	30%	27.64	50.96	119%	32%
Central	59.67	10.42	17.90	30%	7.23	17.65	69%	30%
Southwest	47.17	12.40	14.15	30%	4.73	17.13	38%	36%

Next, tables 6a and 6b show the transmission builds in the Current Policies and 95% CO_2 reduction scenarios, respectively. In the Current Policies setting, we estimate that an addi-

[11] We assume that the MITC is met if 99% of the requirement is met. This was done to avoid rounding and feasibility errors in the programming language used.

tional 53.53 GW of transfer capability will be built, equivalent to 13.23 TW-mi of additional interregional transmission. Most of the expansion is concentrated in the Eastern Interconnect between the Mid-Atlantic and the Southeast (14.91 GW additional transfer capacity; 4.19 TW-mi deployment), Mid-Atlantic and the Midwest (9.52 GW; 2.31 TW-mi), and Florida and the Southeast (8.25 GW; 2.76 TW-mi). New interregional transmission deployment in these corridors represents 61% of additional transfer capability (in GW), and 70% of the total additional interregional transmission builds (in TW-mi) under the BIG WIRES Act. We also observe that there is a more than 700% increase in transfer capability between the Southwest and Central (4.48GW; 1.00 TW-mi). The connection not only takes advantage of Central's wind resources for the Southwest but, more importantly, increases the connection between the Eastern and Western Interconnections. Figure 3 shows the current and additional interregional transmission capability under the No BWA and BWA scenarios in a Current Policies setting. Recall that Texas is not included in the BIG WIRES Act and is reflected in the results with no new interregional transmission builds.

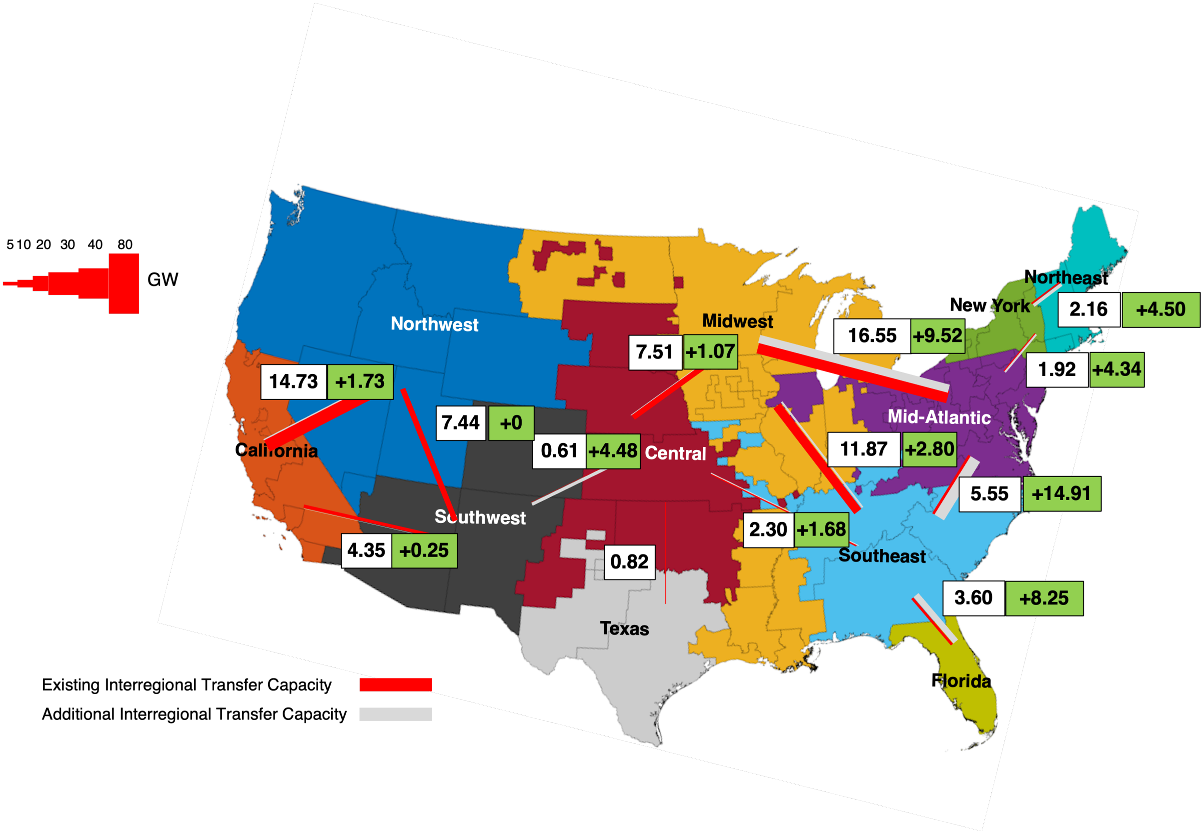


Figure 3: Map of current and additional interregional transfer capability between regions in a Current Policies setting (values are current and additional interregional transfer capability)

In the 95% CO_2 reduction setting, there are 2.5 TW-mi of more transmission built (11.4GW of transfer capability) compared to the Current Policies setting. The additional builds are still concentrated in the Eastern Interconnect, with around 60% of all builds found in big increases to the Southeast.

Table 6: Current and additional interregional transfer capability and transmission builds per corridor

Corridors	Transfer Capability (GW)				Transmission Builds (TW-mi)			
	Current	Additional	Total	% Increase	Current	Additional	Total	% Increase
California – Northwest	14.73	1.73	16.46	12%	5.40	0.48	5.88	9%
California – Southwest	4.35	0.25	4.60	6%	1.30	0.05	1.36	4%
Northwest – Southwest	7.44	-	7.44	0%	1.97	-	1.97	0%
Southwest – Central	0.61	4.48	5.09	735%	0.14	1.00	1.13	735%
Southeast – Central	2.30	1.68	3.98	73%	0.67	0.52	1.19	77%
Florida – Southeast	3.60	8.25	11.85	229%	1.21	2.76	3.97	229%
Mid-Atlantic – Midwest	16.55	9.52	26.06	58%	3.56	2.31	5.87	65%
Mid-Atlantic – New York	1.92	4.34	6.25	227%	0.28	0.47	0.75	168%
Mid-Atlantic – Southeast	5.55	14.91	20.46	269%	1.41	4.19	5.60	297%
Midwest – Central	7.51	1.07	8.58	14%	2.20	0.35	2.55	16%
Midwest – Southeast	11.87	2.80	14.66	24%	2.63	0.80	3.43	30%
Northeast – New York	2.16	4.50	6.66	208%	0.17	0.30	0.47	182%
	78.58	53.53	132.11	68%	20.94	13.23	34.16	63%

(a) Current Policies

Corridors	Transfer Capability (GW)				Transmission Builds (TW-mi)			
	Current	Additional	Total	% Increase	Current	Additional	Total	% Increase
California – Northwest	14.73	1.51	16.24	10%	5.40	0.35	5.75	7%
California – Southwest	4.35	0.47	4.83	11%	1.30	0.14	1.45	11%
Northwest – Southwest	7.44	0.00	7.44	0%	1.97	0.00	1.97	0%
Southwest – Central	0.61	3.25	3.86	533%	0.14	0.72	0.86	533%
Southeast – Central	2.30	2.36	4.66	102%	0.67	0.71	1.38	105%
Florida – Southeast	3.60	8.25	11.85	229%	1.21	2.76	3.97	229%
Mid-Atlantic – Midwest	16.55	7.46	24.01	45%	3.56	1.69	5.25	48%
Mid-Atlantic – New York	1.92	12.85	14.76	671%	0.28	1.70	1.98	610%
Mid-Atlantic – Southeast	5.55	8.46	14.01	152%	1.41	2.33	3.74	165%
Midwest – Central	7.51	1.87	9.38	25%	2.20	0.56	2.76	25%
Midwest – Southeast	11.87	13.92	25.79	117%	2.63	4.42	7.05	168%
Northeast – New York	2.16	4.50	6.66	208%	0.17	0.36	0.53	217%
	78.58	64.91	143.49	83%	20.94	15.76	36.69	75%

(b) 95% CO_2 reduction

3.1.2 Electricity Flows

Next, we will provide an analysis of the changing regional import and export interactions between regions. Figure 4 shows the net exports and imports for varying values of p, the MITC %. In the Current Policies setting, we find that all regions retain their status as a net exporter or net importer. Regions stay at relatively similar magnitudes of net exports and imports than compared to the case where there is no BWA. However, some notable exceptions can be observed. The Southeast relies more on imports from neighboring regions, increasing its net import of electricity from 29.25 TWh to 82.47 TWh. The Central and Midwest regions – with their quality wind resources – export more to other regions in the BWA scenario. Both see net exports increasing from 31.67 TWh and 3.09 TWh to 63.30 TWh and 25.98 TWh, respectively, when $p = 30\%$. The Northwest, while still a net exporter, is the only net exporting region that sees its exports decline because of the BWA.

We also report the net export and import in each corridor in Table 7. In the Current Policies setting, the Southeast imports triple the amount from the Mid-Atlantic in the BWA scenario from 19.66 TWh to 61.83 TWh. This is also the case with the Midwest, where imports increase from 8.85 TWh to 25.07 TWh. The Southeast further imports more power from Central at 8.41 TWh compared to the No BWA scenario of 2.03 TWh. New York becomes a net exporter to the

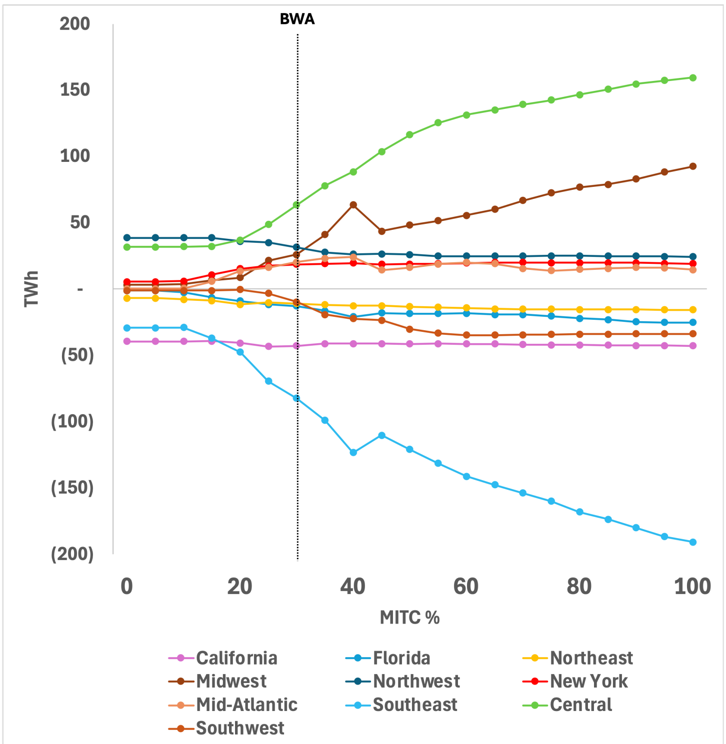


Figure 4: Total Electricity Net Export (Import) per Region

Mid-Atlantic, where previously it was a net importer. The added transfer capability between Central and the Southwest results in a more than ten-fold increase in Central's electricity exports to the Southwest from 1.97 TWh to 21.17 TWh. As we will discuss in section 3.3.1, this reliance on transfers from Central to the Southwest will raise concerns on reliability during extreme weather events.

Table 7: Net Export (Import) per corridor (in TWh)

		Current Policies		95% CO_2 Reduction	
From	To	No BWA	BWA	No BWA	BWA
California	Northwest	(27.91)	(26.42)	(61.31)	(59.29)
California	Southwest	(11.53)	(16.44)	(6.98)	(4.67)
Northwest	Southwest	10.71	5.08	22.88	21.18
Central	Southwest	1.97	21.17	2.32	18.24
Southeast	Central	(2.03)	(8.41)	(8.94)	(20.33)
Florida	Southeast	(1.30)	(12.84)	(10.39)	(51.15)
Midwest	Mid-Atlantic	20.99	33.79	20.42	21.69
New York	Mid-Atlantic	(1.49)	7.70	3.17	25.02
Mid-Atlantic	Southeast	19.66	61.83	(1.78)	15.50
Midwest	Central	(26.75)	(32.87)	(20.75)	(31.44)
Midwest	Southeast	8.85	25.07	6.25	52.70
Northeast	New York	(6.97)	(10.99)	(3.54)	(6.68)
Central	Texas	0.92	0.85	0.21	(0.26)

Figure 5 shows the average capacity factors for interregional transmission lines with the BWA under the Current Policies setting. Consistent with the large electricity transfers between the Southeast and the Mid-Atlantic and Midwest in Table 7, we find that four lines connecting the Southeast to the Mid-Atlantic and Midwest have high capacity factors of 75% or larger. Similarly, we also see a high capacity factor of 70% in the transmission line connecting Central and the Southwest regions. The Florida and Southeast corridor sees large transmission builds but the smallest capacity factor at 20%. This indicates that the prescribed MITC requirement might be much larger in Florida than what is cost optimal for the system.

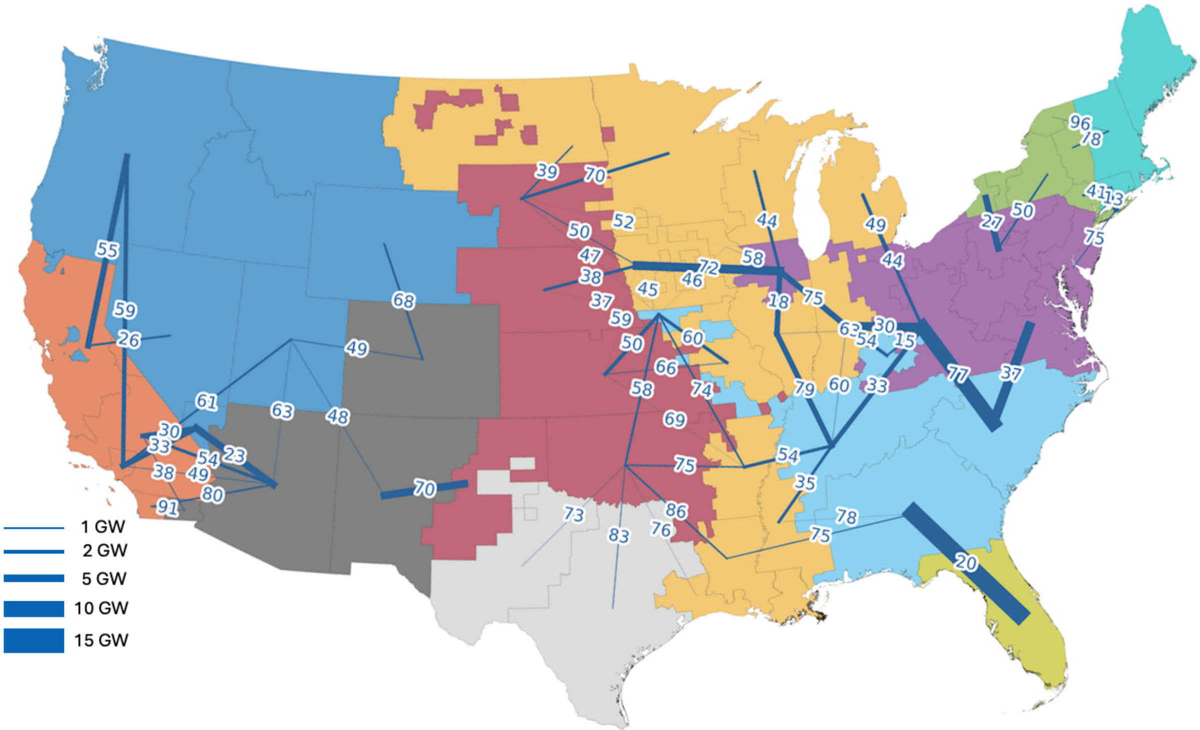


Figure 5: Average Capacity Factors for Interregional Lines

3.2 Cost, Capacity, and Generation Mix

3.2.1 System Cost

We next discuss the impact of the BIG WIRES Act on system cost, capacity, and generation mix. We find that the BIG WIRES Act leads to annual system cost savings of $487 million for the Current Policies scenario and $3.21 billion for the 95% CO_2 reduction scenario relative to the status quo. This result shows that the BIG WIRES Act facilitates larger savings in low-carbon systems. We examined this further in Figure 6, illustrating the cost differences between the BIG WIRES Act and the status quo for each cost component. For ease of exposition, we also illustrate the investments in new generation capacity per scenario in Figure 7. In the Current Policies scenario, the savings are driven by lower fuel costs from increased solar and wind generation capacity investments (i.e., new generation investments in Solar and Wind increase from 197GW and 146GW to 201GW and 161GW, respectively). This re-emphasizes how interregional transmission further facilitates the use of renewables by giving regions access to more quality wind and solar resources (Brown and Botterud, 2021; Joskow, 2020). Investment in new intraregional transmission also increases because more renewables under the BIG WIRES

Act also needs to be transferred effectively within each region.

The value of transmission in cleaner grids is more apparent. In the 95% CO_2 reduction target scenario, there are savings on investments in new generation, fixed O&M, and fuel costs. The high decarbonization target means a greater reliance on renewables, leading to a larger solar, wind, and battery storage fleet than when there is no CO_2 target under the Current Policies scenario. Without additional interregional transmission, regions would have to complement the variability of renewables with investment in thermal units – 8GW of new nuclear technology and 13GW of natural gas capacity (see Figure 7). With more interregional transmission, regions are able to import renewable resources from their neighbors instead during instances of low VRE capacity factors within the region. The reliance on thermal technologies is then reduced, resulting in lower capacity investment, fuel, and fixed O&M costs.

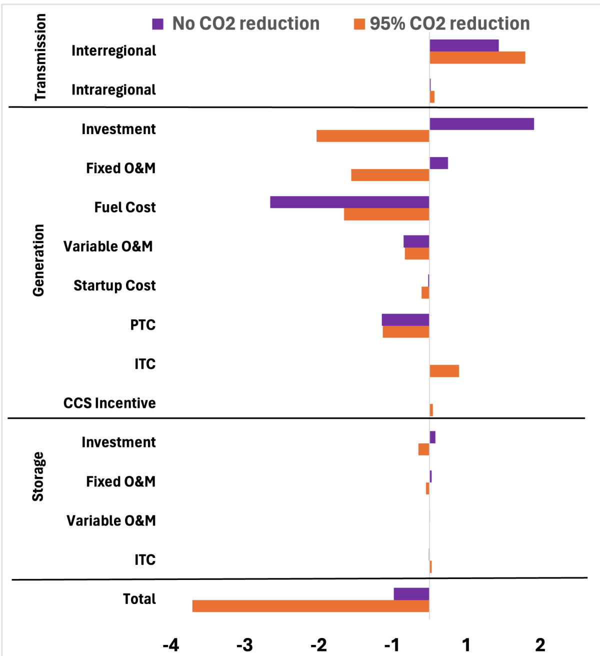


Figure 6: System cost difference of the BIG WIRES Act vs Status Quo (Billion $)

While Figure 7 shows an increase in wind and solar generation capacity, it does not capture how much transmission influences the capacity investment decisions of each region. What we find is that changing transmission requirements also facilitates a spatial shift of where capacity investments are made. Figure 8 shows the new capacity investments per region in a Current Policies setting. As the MITC % increases, there are more investments in wind generation capacity in Central, Midwest, and New York. Meanwhile, wind generation capacity investments are lower in the Northwest, Southeast, and Southwest. It would be cheaper overall to use the rich resources in regions with high wind capacity factors and move electrons to other regions than to build separate capacity in regions with lower wind capacity factors. Not surprisingly, the regions with more wind generation capacity investments have increased exports. The regions with less wind generation capacity investments have increased imports (see Figure 4).

We also evaluated variation in the MITC in the BIG WIRES Act to find the cost-optimal p. Figures 9a and 9b show the total annual system cost at varying MITC % values for the

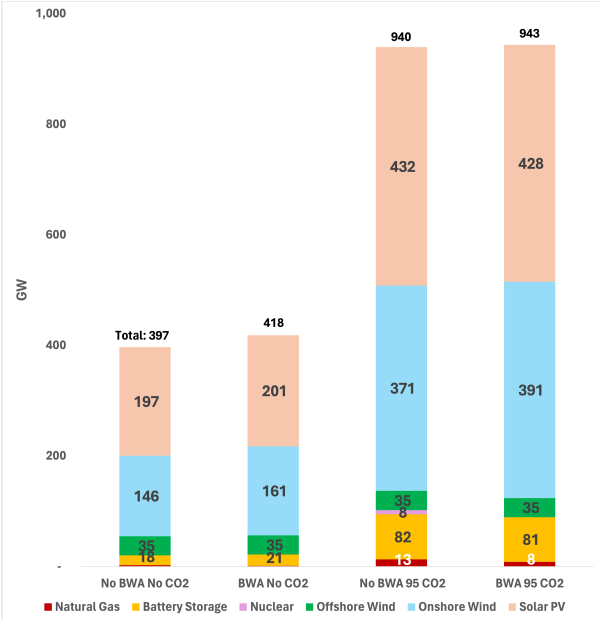


Figure 7: New generation capacity per scenario

Current Policies and 95% CO_2 reduction target scenarios, respectively. The dashed horizontal line represents the system cost of the status quo. Based on 5% increments from $p = 0$ to 100%, an MITC constraint between 20 and 55% of peak load leads to cost savings in the Current Policies scenario. Below 5%, regions would already meet the MITC, from 10 to 15%, and beyond 55%, the cost of building transmission outweighs the system cost savings in generation. Interestingly, the optimal p in this scenario is at 30% – exactly what the BIG WIRES Act proposes. In the 95% CO_2 reduction scenario, there is savings beyond 10% of peak load, and the minimum is at 75%. The continued cost decrease shown in the results of the 95% CO_2 reduction scenario provides evidence of transmission's role in ensuring the cost efficiency of the power sector in a low-carbon future.

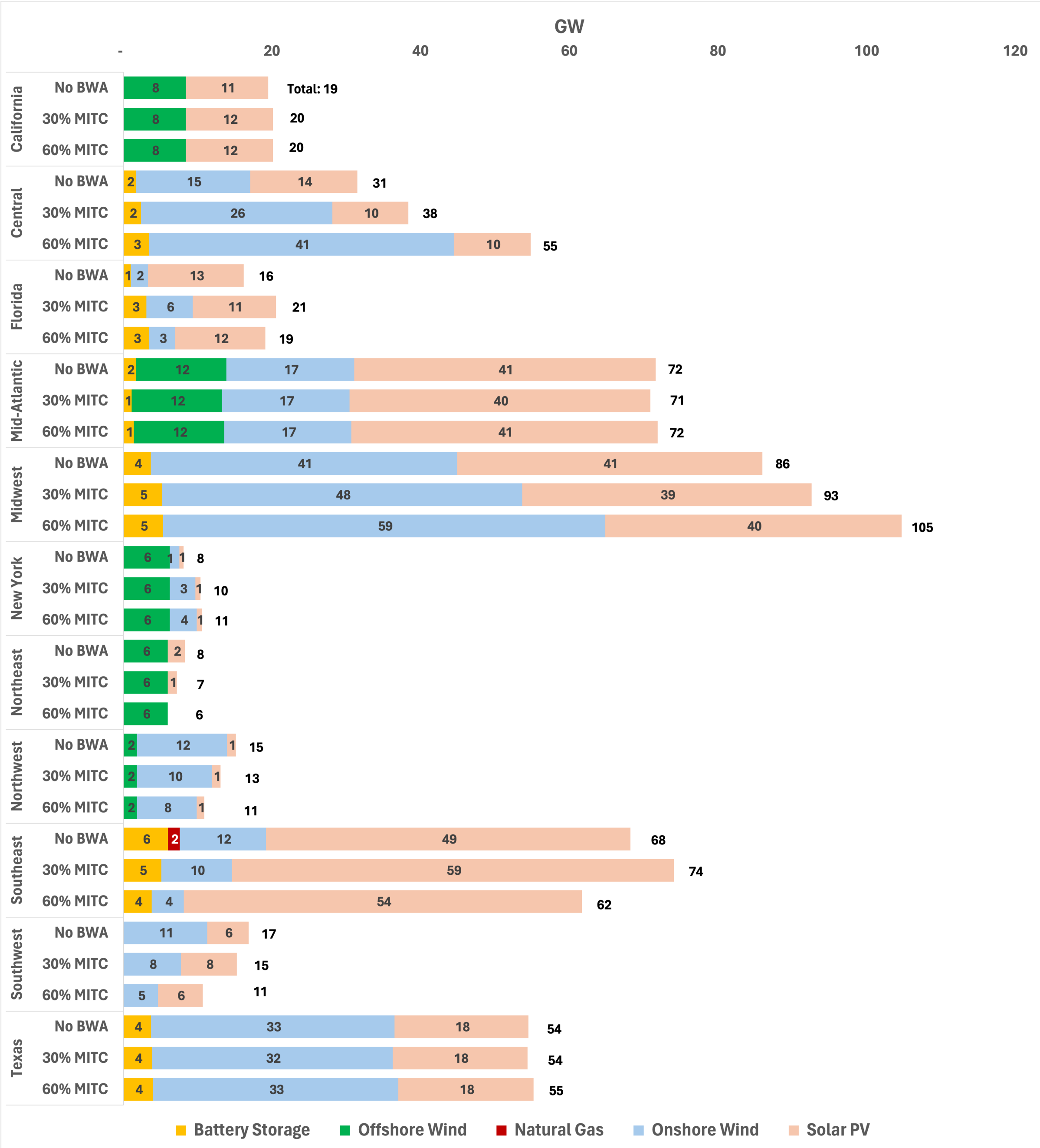
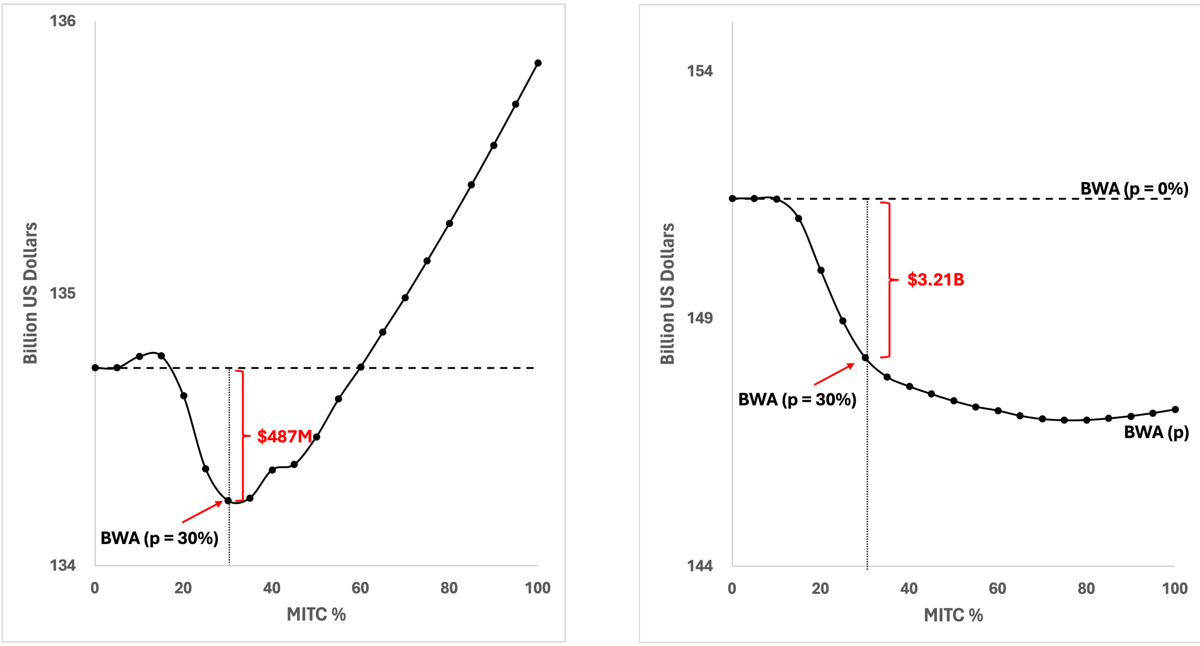


Figure 8: New generation capacity in the Current Policies setting

3.3 Reliability during Extreme Weather Events

Transmission infrastructure is believed to increase the power system's reliability and mitigate the impact of extreme weather events. To test this hypothesis, we used the extreme event methodology detailed in section 2.5 to simulate natural gas outages for each individual region. This is inspired by the regional events of Winter Storm Elliot which led to 80.5 GW of natural gas ($y = NG$) generation capacity experiencing derates, unplanned outages, or failures to start in the Mid-Atlantic and Southeast in December 21-26, 2022 (Howland, 2023).[12] We isolated each

[12] 80.5 GW represents 80 to 90% of total outages during Winter Storm Elliot.



(a) Current Policies

(b) 95% CO_2 reduction

Figure 9: Annual system cost curve per MITC % Peak Load Calculation

region and simulated each at an outage level of $q_{NG,r} = 80\%$.[13,14] This is done across different MITC % values: $p \in \{0\%, 10\%, \ldots, 60\%\}$ to enable comparisons across different interconnection levels. Table 8 shows the amount of natural gas capacity outages in the 80% outage scenario. We run the GenX dispatch model 1,000 times for each region and MITC % combination from December 21 to December 26 of the model year (i.e., 144 hours – the duration and dates of Winter Storm Elliot). The random outages were present in each simulated dispatch, and the average non-served energy across the 144 hours and 1,000 simulations was calculated. Consistent with the events of Winter Storm Elliot, where the actual peak load during the storm exceeded the forecasted peak load by 6%, we assume an increased load of 6% for the affected regions throughout the simulation.

Table 8: 80% Natural Gas Outages per Region in GW (Percentage of Outages Relative to Total Capacity Mix in the Region

	MITC %						
	0	10	20	30	40	50	60
Mid-Atlantic/Southeast	146.8 (30%)	146.8 (30%)	145.4 (30%)	145.5 (30%)	145.6 (30%)	145.6 (30%)	145.6 (31%)
Midwest	62.4 (25%)	62.3 (25%)	62.4 (24%)	63.4 (24%)	63.5 (24%)	63.4 (24%)	63.5 (24%)
Florida	41.1 (51%)	41.1 (50%)	41.1 (49%)	41.1 (48%)	41.1 (50%)	41.1 (49%)	41.1 (49%)
New York	14.4 (36%)	14.2 (36%)	16.2 (38%)	15.5 (36%)	15.1 (35%)	15.8 (37%)	15.6 (36%)
Northeast	14.4 (38%)	14.4 (38%)	14.4 (39%)	14.4 (39%)	14.4 (39%)	14.4 (39%)	14.4 (40%)
California	29.9 (29%)	29.9 (29%)	29.4 (28%)	28.5 (28%)	27.8 (27%)	27.6 (27%)	27.6 (27%)
Texas	51.7 (28%)	51.7 (28%)	51.7 (28%)	51.7 (28%)	51.7 (28%)	51.7 (28%)	51.7 (28%)
Southwest	18.9 (25%)	18.9 (25%)	18.9 (25%)	18.9 (26%)	18.9 (28%)	18.9 (28%)	18.2 (28%)
Northwest	16.3 (15%)	16.3 (15%)	16.3 (15%)	16.3 (15%)	16.3 (16%)	16.3 (16%)	16.3 (16%)
Central	25.7 (23%)	25.7 (23%)	25.2 (22%)	24.1 (21%)	24.3 (20%)	24.3 (19%)	24.2 (18%)

[13]We also ran a simulation for $q_{NG,r} = 40\%$, which have similar results but are smaller in magnitude compared to $q_{NG,r} = 80\%$

[14]One simulation affects the Mid-Atlantic and Southeast similar to the events of Winter Storm Elliot.

Our results indicate that increased transmission through MITC requirements lead to a substantial reduction in average generation outages during extreme weather events (see Table 9). The majority of these reliability benefits are seen in the Mid-Atlantic/Southeast and the Florida regions, which coincide with the regions where most of the transmission builds under the BWA are done. These results provide evidence supporting the need for more transmission to ensure grid reliability during extreme weather events. We also observe that the benefits level off at varying levels of p for each region. The Florida, New York, and Northeast regions have at least 61% lower outages even at modest implementations of the BWA at $p = 20\%$. For some regions like the Northwest and Central, implementing interregional transmission will likely lead to no outages when gas plants go down.

Table 9: Average Hourly Outages in MWh $N\bar{\bar{S}}E$ (% Reduction relative to MITC % = 0)

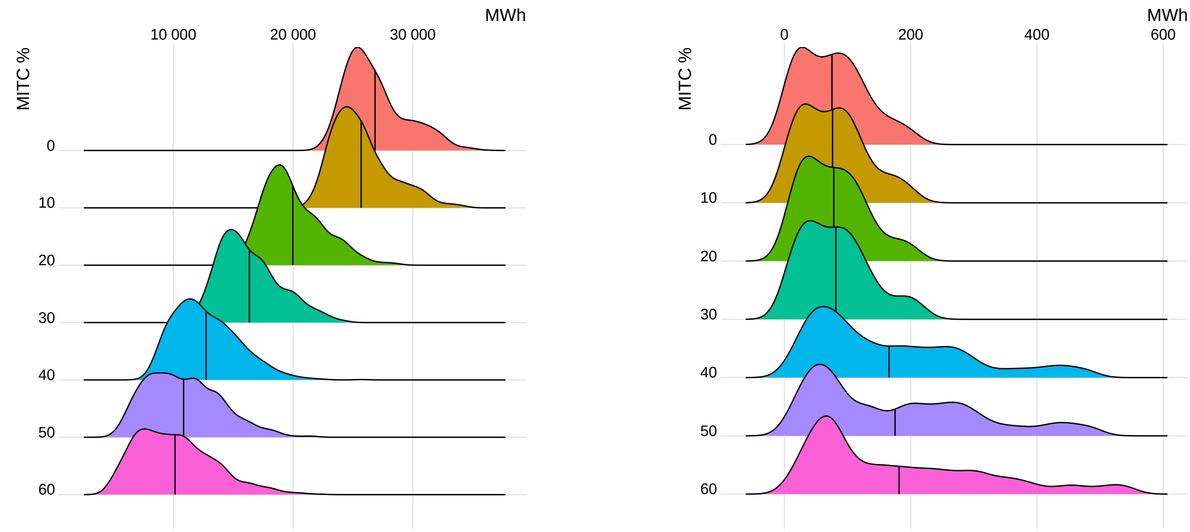
	MITC %						
	0	10	20	30	40	50	60
Mid-Atlantic/Southeast	26,842 (0%)	25,682 (4%)	19,974 (26%)	16,350 (39%)	12,734 (53%)	10,854 (60%)	10,140 (62%)
Midwest	1,040 (0%)	1,095 (-5%)	1,007 (3%)	962 (8%)	538 (48%)	531 (49%)	507 (51%)
Florida	7,544 (0%)	5,661 (25%)	2,960 (61%)	1,678 (78%)	1,168 (85%)	506 (93%)	145 (98%)
New York	2,022 (0%)	1,539 (24%)	561 (72%)	618 (69%)	636 (69%)	589 (71%)	598 (70%)
Northeast	2,295 (0%)	1,865 (19%)	848 (63%)	814 (65%)	639 (72%)	435 (81%)	369 (84%)
California	186 (0%)	182 (2%)	181 (3%)	99 (47%)	29 (84%)	24 (87%)	14 (92%)
Texas	2,208 (0%)	2,197 (0%)	2,195 (1%)	2,196 (1%)	2,177 (1%)	2,194 (1%)	2,238 (-1%)
Southwest	77 (0%)	76 (1%)	74 (4%)	81 (-5%)	166 (-115%)	175 (-127%)	182 (-135%)
Northwest	56 (0%)	55 (1%)	55 (1%)	12 (78%)	0 (100%)	0 (100%)	0 (100%)
Central	3 (0%)	2 (26%)	0 (97%)	0 (100%)	0 (100%)	0 (100%)	0 (100%)

3.3.1 Regional Reliance on Transmission

In most cases, we see from Table 9 that more transmission leads to higher resilience from extreme weather events. However, we also observe that some regions experience higher outages at higher MITC %. The Southwest, in particular, has this characteristic. If we plot the resulting distribution of average outages across all simulations for the Southwest (see Figure 10b), we can see that a higher MITC % results in a more spread out distribution which is skewed to larger values when p is greater than or equal to 40%.[15] In contrast, the Mid-Atlantic and Southeast's (Figure 10a) outage distribution remains relatively similar, shifting to lower mean values at larger values of MITC %. This is because the Southwest relies more on electricity imports from other regions as MITC % increases. Figures 11a and 11b illustrate this point. In the No BWA scenario, when there is no extreme weather event (Figure 11a: red curve, color online), the region mostly exports electricity to other regions during these hours. The curve shifts downwards during extreme weather events, when it utilizes its existing connections to other regions to import electricity. In the BWA scenario (Figure 11b), the Southwest already imports extensively throughout the duration when there is no extreme weather event and ends up requiring more imports during the extreme weather event. Why does this happen? With more transmission, the cost-optimizing objective of the model translates to less "domestic" capacity located in the Southwest (Figure 12), opting to import instead. As a result, the region has less domestic generation to mitigate outages in its natural gas plants. Meanwhile,

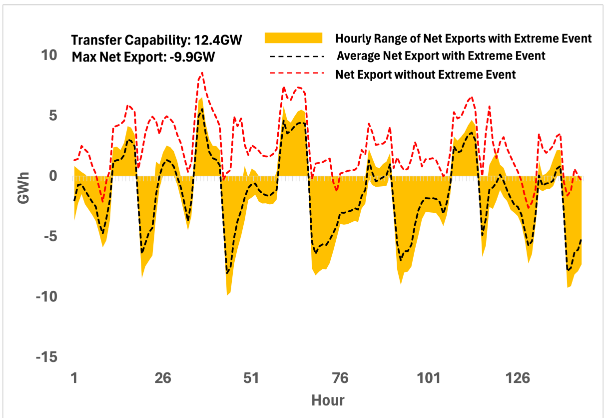
[15]We note that the scale of outages differ between the Southwest and the Mid-Atlantic/Southeast regions. The Southwest sees much lower outages.

an increase in import requirements becomes harder to facilitate as its transmission lines are already being utilized even during non-extreme weather event scenarios.

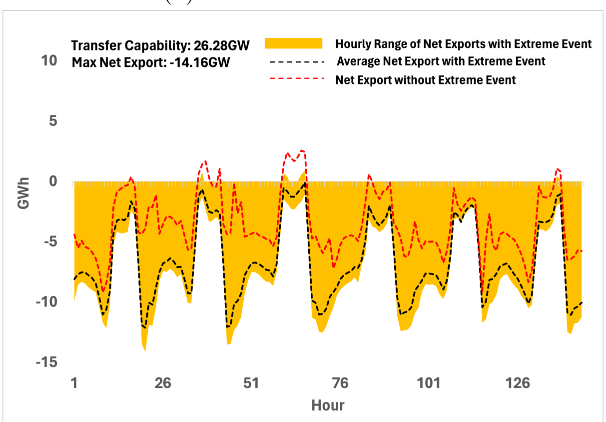


(a) Mid-Atlantic and Southeast (b) Southwest

Figure 10: Distribution of Simulated Average Outages



(a) No BIG WIRES Act



(b) BIG WIRES Act (60% MITC)

Figure 11: Southwest's Electricity Net Export (Import) during Extreme Weather Events

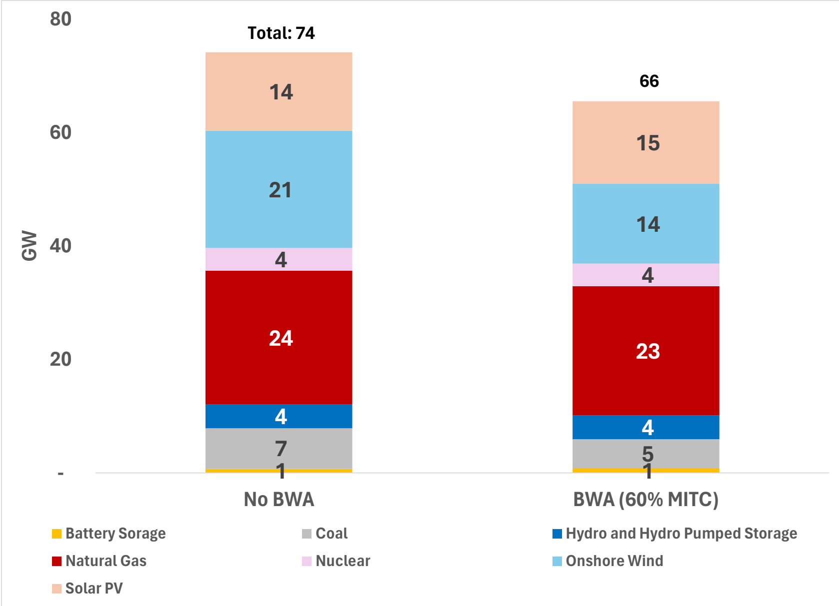


Figure 12: Southwest's Capacity Mix

3.4 Climate Impacts

Next, we discuss the climate impact of the BIG WIRES Act, under the assumption that no CO2 constraint is in place. We assume that CO_2 emissions are assigned to the region where they are generated.[16] We find that increased transmission consistently leads to lower CO_2 emissions as seen in Figure 13. This is again because of more renewables in a more interconnected grid and the consequent reduction in generation from fossil fuels. In particular, the BIG WIRES Act leads to 43 million metric tons (Mmt) less CO_2 emissions compared to the No BWA scenario. This translates to roughly \$8.2 billion of annual savings based on the EPA's proposed estimate for the social cost of carbon of \$190 per metric ton (EPA, 2023b).

The lower CO_2 emissions in the Current Policies setting mainly comes from the Southeast (see Figure 14) where it reduces its coal and natural gas generation in favor of more PV generation and imports from neighboring regions (see Figures 4 and 15). When $p = 30\%$, the Southeast sees 42 Mmt lower CO_2 emissions compared to when $p = 0\%$. The imports into the Southeast come from the Mid-Atlantic region, which then sees a slight increase in emissions. However, the increase is still dwarfed by the much lower emissions in the Southeast. Under the 95% CO_2 policy settings, emissions are constant across MITC levels, so the climate benefit of the BIG WIRES Act materializes in terms of savings in system cost when it is implemented.

[16] Another assumption may be to allocate emissions according to where the power is used, similar to what the Regional Greenhouse Gas Initiative (RGGI) states use. However, the GenX model is not set up to keep track of carbon emissions by electricity use.

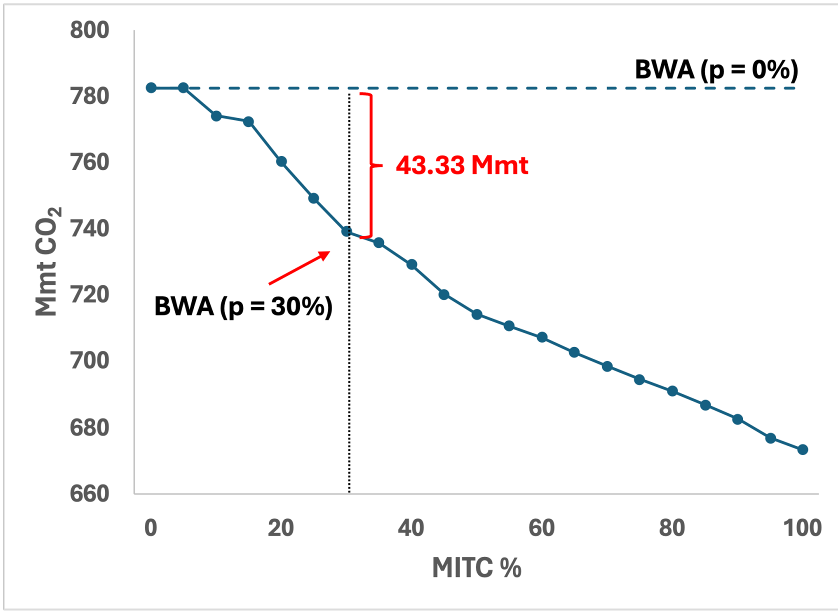


Figure 13: Total Emissions per MITC % under Current Policies

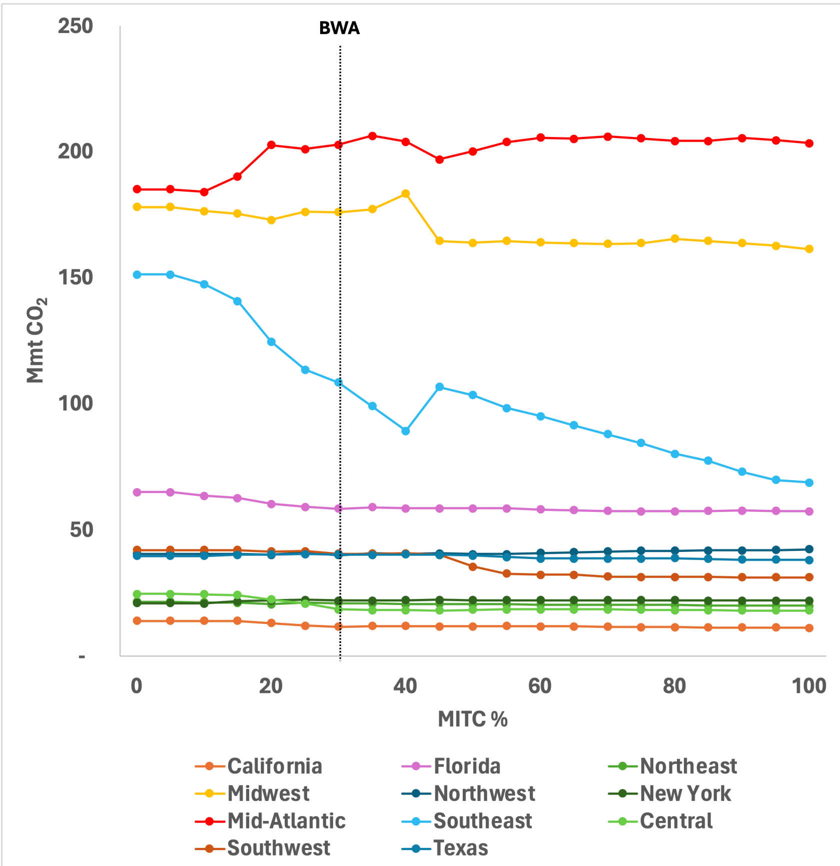


Figure 14: Regional Emissions per MITC %

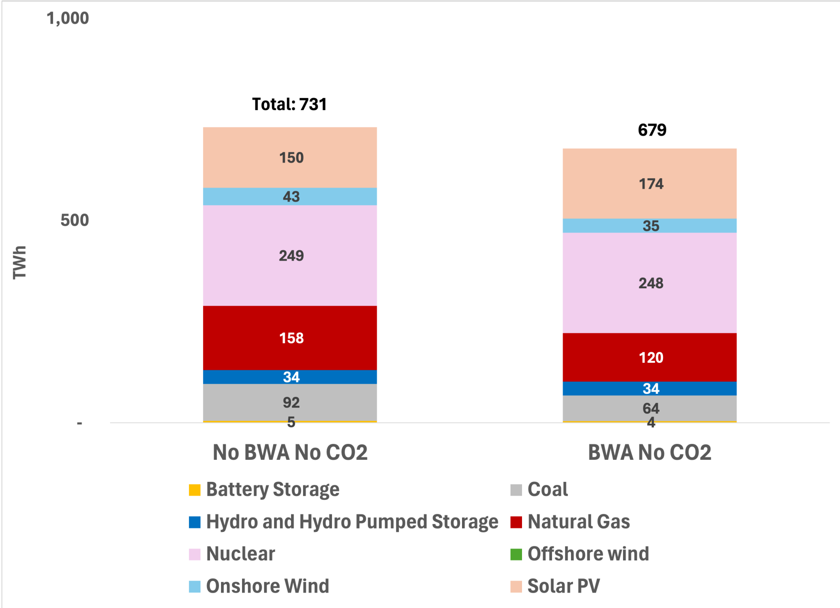


Figure 15: Generation Mix for the Southeast ($p = 30\%$ for BWA)

4 Extensions to Other Proposed Policies and Alternative Calculations of MITC

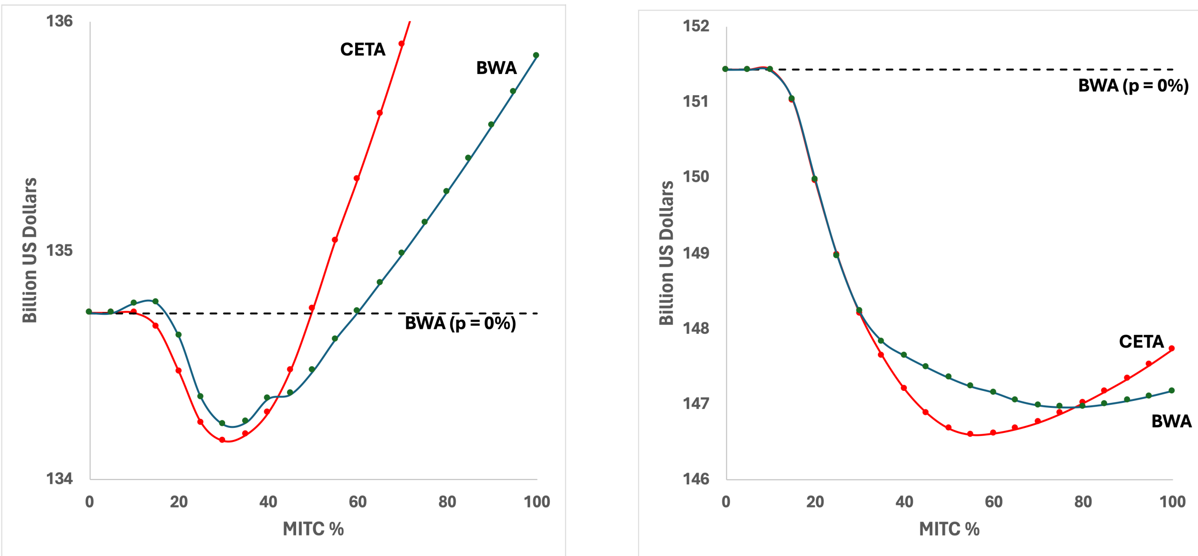
4.1 Clean Electricity and Transmission Acceleration Act

Another proposed bill is the Clean Electricity and Transmission Acceleration Act (CETA) (H.R.6747 - 118th Congress). CETA has multiple provisions in the areas of offshore wind mandates, clean energy deployment on public land, rate making, and minimum interregional transmission requirements (Casten, 2024). The difference with the BWA is how CETA calculates its MITC. CETA specifies a 30% of peak load requirement if a region borders at least two regions, and 15% of peak load if a region only borders one.[17] This means all regions except the Northeast and Florida will follow the 30% requirement. Figures 16a and 16b show the system cost curves of CETA and BWA. We find that CETA builds more transmission between the Mid-Atlantic and the Southeast, which reduces cost for low to intermediate values of MITC %.

4.2 Actual Flow as MITC

In section 2.3, we discussed that the BIG WIRES Act specifies actual flows as its way of measuring transfer capability. In contrast, we used the EPA's definition of transfer capability in our analysis. One of the difficulties of using the BWA definition is that historical flow data are used to determine transfer capability in 2035. Furthermore, it is also possible that even with a build-out of more transmission, the transfers between regions would not increase proportionally because of the dispatch and transmission decisions being made. Strictly using the BWA definition would mean having more transmission, but not demonstrating a transfer of 30% of peak load will not satisfy the MITC requirement.

[17]There is also a tax credit for transmission builds in CETA if a transmission line meets capacity and connection criterion but we do not include it in this model.



(a) Current Policies (b) 95% CO_2 reduction

Figure 16: Comparison of annual system cost between CETA and BWA

To address this concern, we propose an alternative method that starts with the ratio between the EPA transfer capability and the BIG WIRES Act's definition of transfer capability. Mathematically, we define this ratio for each region r as ρ_r as follows:

$$\rho_r = \frac{\hat{TC}_r}{\hat{TC}_r^{\text{BWA Def}}}, \tag{4}$$

where $\hat{TC}_r^{\text{BWA Def}}$ is the maximum between the absolute values of the 0.01^{th} and 99.9^{th} percentile of coincident hourly electrical transfers for a region r in the No BWA scenario (i.e., the BIG WIRES Act's definition). ρ_r then represents the amount of transmission capacity needed to allow the transfer of one MW of electricity from region r. The MITC formula in (3) can be changed to:

$$MITC'_r(p) = \min\left(p\bar{D}_r, \frac{p}{2}\bar{D}_r + \hat{TC}_r^{\text{BWA Def}}\right). \tag{5}$$

The actual builds needed between each region is then the product $\rho_r MITC'_r(p)$.[18] We call this methodology the *BWA Actual Flow* approach, while the original analysis is called the *BWA EPA* approach. Table 10 shows the calculation of ρ_r and the transfer capability for the BWA Actual Flow approach while the system cost curves for both approaches can be found in Figures 17a and 17b.

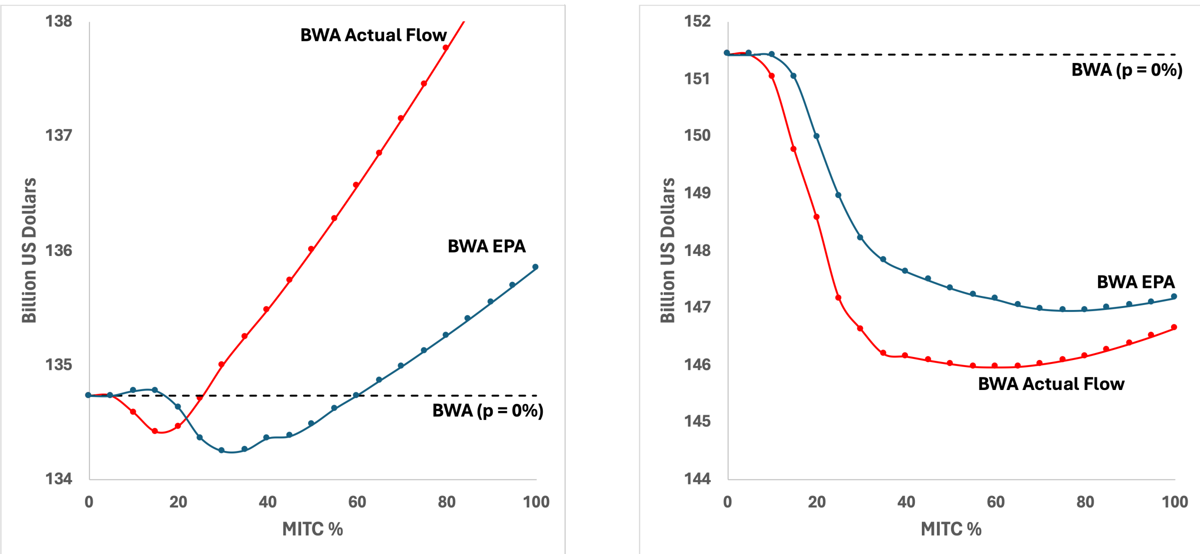
With the BWA Actual Flow approach, more transmission will be built per p. In the Current Policies setting, the BWA at $p = 30\%$ is more expensive than the No BWA case, and varying p only results in cost savings for a smaller range of values from 10 to 20% of peak load. Conversely, the 95% CO_2 reduction scenario generally benefits from more transmission even in the BWA EPA approach, as evidenced by savings at all tested values of $p \geq 15\%$. As in previous results,

[18]We assume that the ratio ρ_r remains constant, which is likely not the case in reality. However, obtaining the actual ratio is a difficult process that requires knowledge and evaluation of the operation of individual transmission lines. Additionally, the consequential decisions that RTOs and ISOs make in using the lines as more transmission is added further increase the complexity of the problem.

Table 10: ρ_r and Current Transfer Capability calculations (in GW)

	$\hat{TC}_r$	Current Policies		95% CO_2 Reduction	
		$\hat{TC}_r^{\text{BWA Def}}$	ρ_r	$\hat{TC}_r^{\text{BWA Def}}$	ρ_r
California	19.08	12.18	1.57	16.68	1.14
Florida	3.60	3.60	1.00	3.60	1.00
Northeast	2.16	2.16	1.00	2.16	1.00
Midwest	35.92	12.89	2.79	18.03	1.99
Northwest	22.17	11.42	1.94	19.95	1.11
New York	4.08	4.07	1.00	4.07	1.00
Mid-Atlantic	24.01	13.17	1.82	16.12	1.49
Southeast	23.32	12.07	1.93	15.36	1.52
Central	10.42	10.42	1.00	10.41	1.00
Southwest	12.40	7.85	1.58	9.22	1.34

transmission in a renewables-dominated grid allows zones to transfer quality wind and solar resources to load centers. Having more transmission builds in the BWA Actual Flow approach at all values of MITC % thus increases this propensity for renewable energy transfers and results in larger savings. Note that the BWA Actual Flow approach is a simplification of the capacity



(a) Current Policies

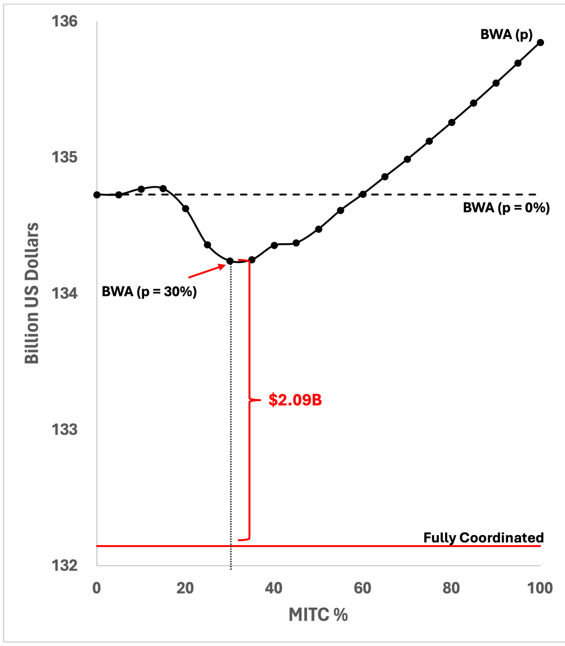
(b) 95% CO_2 reduction

Figure 17: Comparison of annual system cost between BWA EPA and BWA Actual Flow

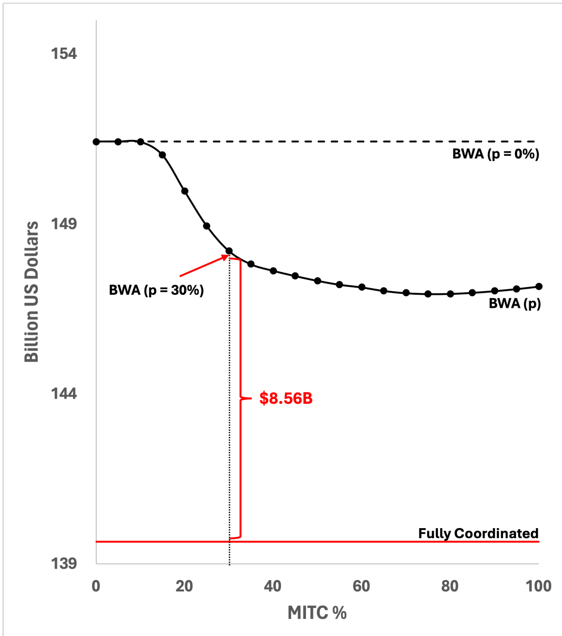
needed to reliably transfer a certain amount of electricity across regions. However, this provides a simple estimate for calculating how much transmission needs to be built by each region if the strict definition for transfer capability in the BWA is followed.

4.3 Region-Dependent MITC

Suppose we relax our assumption that regions will only build up to the MITC and allow the model to build an unlimited amount of interregional transmission optimized for each individual connection. This scenario represents a fully coordinated US grid – different from our assumptions that regions and zones will not build interregional transmission unless there is an MITC requirement. The result of the fully coordinated grid is a system-cost-optimal solution. Figures 18a and 18b show the fully coordinated grid system cost as a solid horizontal line along with the BWA system costs. The fully coordinated grid results in \$2.09 and \$8.56 billion lower cost compared to the BWA scenarios in the Current Policies and 95% CO_2 reduction settings. This result is expected, as having no limitations and requirements on interregional transmission builds allows the system to efficiently allocate resources and link load centers with VRE resources in an optimal manner.



(a) Current Policies



(b) 95% CO_2 reduction

Figure 18: Comparison of annual system cost with a fully coordinated grid

Given the transmission builds per region, we can calculate its ratio relative to the peak load ($\frac{\text{Total}}{D_r}$), as is shown in Table 11. We can see that the values for $\frac{\text{Total}}{D_r}$ vary greatly from the MITC when $p = 30\%$.

Table 11: Transfer Capability per Region in a Fully Coordinated Scenario (GW)

					Current Policies			95% CO_2 Reduction		
	Peak Load	Current	MITC	$\frac{MITC}{D_r}$	Additional	Total	$\frac{\text{Total}}{D_r}$	Additional	Total	$\frac{\text{Total}}{D_r}$
California	70.9	19.1	21.3	30%	0.9	19.9	28%	0.7	19.8	28%
Florida	55.8	3.6	12.0	21%	1.8	5.4	10%	11.2	14.8	27%
Northeast	30.5	2.2	6.7	22%	0.1	2.3	8%	2.8	5.0	16%
Midwest	157.5	35.9	47.3	30%	106.3	142.2	90%	314.1	350.0	222%
Northwest	65.7	22.2	19.7	30%	8.0	30.2	46%	21.4	43.6	66%
New York	33.6	4.1	9.1	27%	0.5	4.6	14%	5.3	9.4	28%
Mid-Atlantic	195.3	24.0	53.3	27%	44.5	68.5	35%	169.8	193.8	99%
Southeast	160.3	23.3	47.4	30%	44.1	67.5	42%	88.9	112.2	70%
Central	59.7	10.4	17.9	30%	58.0	68.4	115%	134.4	144.8	243%
Southwest	47.2	12.4	14.2	30%	24.7	37.1	79%	44.2	56.6	120%

Tables 12a and 12b compare the per corridor interregional transfer capability between the

BWA and Fully Coordinated scenarios. The Fully Coordinated scenario builds more overall transmission, with large percentage transmission increases in the Southwest – Central and Midwest – Central corridors. The corridors where the majority of transmission gets built create a *long chain* of transfer capability that spans from the eastern interconnect to the western interconnect from the Mid-Atlantic to the Midwest, Central, Southwest, and Northwest (see Figure 19). This set of transmission builds enables the most efficient use of renewable resources by taking advantage of higher capacity factors (due, in part, to timezone differences) on one side of the US and transferring it to the other side. This is illustrated further in the detailed transmission builds at a zonal level for the Fully Coordinated scenario in Figure 20a. The first large transmission chain starts from the Southeast to the lower portion of the Midwest, to Central, Southwest and the Northwest. The second starts from the Southeast, goes to the Mid-Atlantic, then proceeds to the same path in the Midwest, Central, Southwest, and the Northwest. Meanwhile, the detailed builds of the BWA in 20b shows that these long transmission chains exist but are much smaller than in the Fully Coordinated scenario.

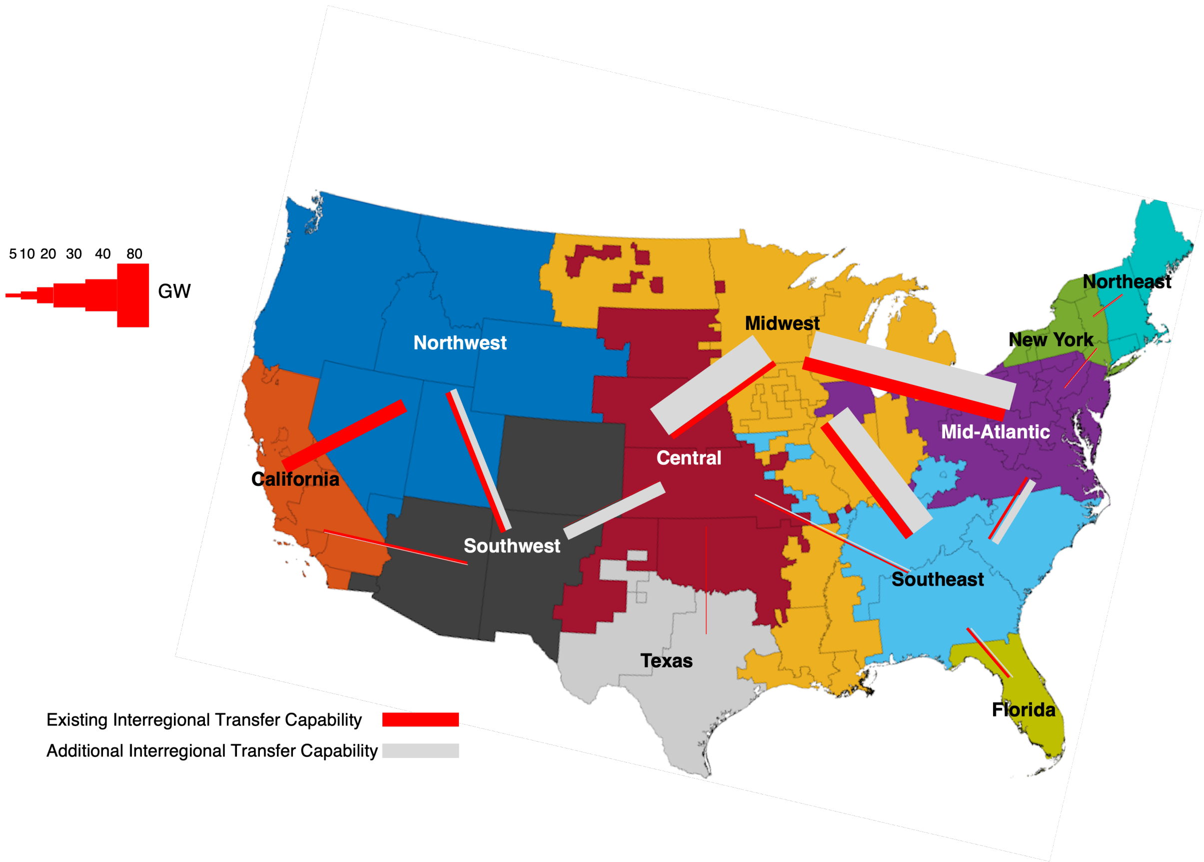
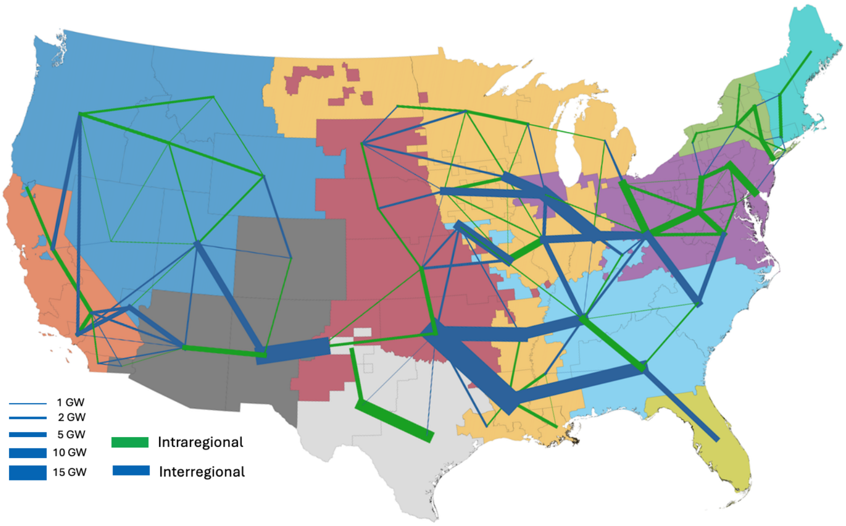
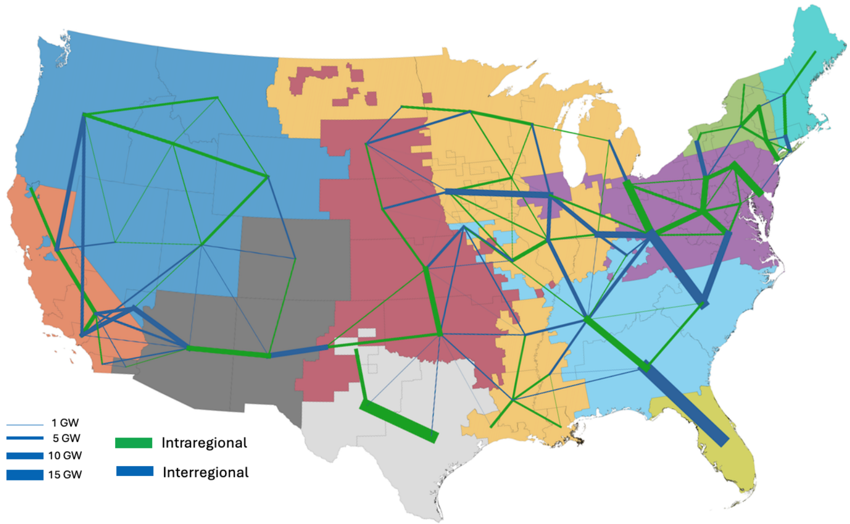


Figure 19: Map of current and additional interregional transfer capability between regions in a Fully Coordinated scenario (Current Policies setting)



(a) Fully Coordinated scenario



(b) BIG WIRES Act scenario

Figure 20: Intraregional and interregional transmission lines between zones

5 Policy Implications and Conclusion

The results presented in this study show that the BIG WIRES Act and MITC requirements can facilitate many benefits for the US power system. We provide evidence that the BIG WIRES Act and interregional transmission lowers cost, increases reliability, and reduces GHG emissions. The BIG WIRES Act would increase interregional transmission capability across the US. Most of this additional transmission would be concentrated in the Eastern Interconnect, which is a direct result of the way the MITC is calculated. The higher peak loads in the east translate to higher MITC requirements for these regions. Since each region uses the same calculation for its MITC requirement, there will also be regions that will have to build more than their individual requirement. Transmission builds would also be located between regions with high VRE potential and high demand. As a result, total annual system costs will decrease for an intermediate set of percentages of peak load requirements because more efficient renewables can be accessed by load centers. This is more evident in a system with a strict carbon constraint. The

Table 12: Per corridor comparison of additional interregional transfer capability between the Fully Coordinated and BWA scenarios

		Fully Coordinated			BWA		
Regions	Current	Additional	Total	% Increase	Additional	Total	% Increase
California – Northwest	14.73	0.00	14.73	0%	1.73	16.46	12%
California – Southwest	4.35	0.85	5.21	20%	0.25	4.60	6%
Northwest – Southwest	7.44	8.01	15.45	108%	-	7.44	0%
Southwest – Central	0.61	15.79	16.40	2,589%	4.48	5.09	735%
Southeast – Central	2.30	1.71	4.01	74%	1.68	3.98	73%
Florida – Southeast	3.60	1.78	5.38	50%	8.25	11.85	229%
Mid-Atlantic – Midwest	16.55	34.61	51.16	209%	9.52	26.06	58%
Mid-Atlantic – New York	1.92	0.39	2.31	20%	4.34	6.25	227%
Mid-Atlantic – Southeast	5.55	9.48	15.03	171%	14.91	20.46	269%
Midwest – Central	7.51	40.48	47.99	539%	1.07	8.58	14%
Midwest – Southeast	11.87	31.16	43.03	263%	2.80	14.66	24%
Northeast – New York	2.16	0.13	2.29	6%	4.50	6.66	208%
	78.58	144.41	222.99	184%	53.53	132.11	68%

(a) Current Policies

		Fully Coordinated			BWA		
Regions	Current	Additional	Total	% Increase	Additional	Total	% Increase
California-Northwest	14.73	0.09	14.82	1%	1.51	16.24	10%
California-Southwest	4.35	0.65	5.00	15%	0.47	4.83	11%
Northwest-Southwest	7.44	21.34	28.77	287%	-	7.44	0%
Southwest-Central	0.61	22.22	22.83	3,643%	3.25	3.86	533%
Southeast-Central	2.30	5.08	7.39	221%	2.36	4.66	102%
Florida-Southeast	3.60	11.19	14.79	311%	8.25	11.85	229%
Mid-Atlantic-Midwest	16.55	150.82	167.37	911%	7.46	24.01	45%
Mid-Atlantic-New York	1.92	2.49	4.40	130%	12.85	14.76	671%
Mid-Atlantic-Southeast	5.55	16.47	22.02	297%	8.46	14.01	152%
Midwest-Central	7.51	107.11	114.62	1,426%	1.87	9.38	25%
Midwest-Southeast	11.87	56.14	68.00	473%	13.92	25.79	117%
Northeast-New York	2.16	2.83	4.99	131%	4.50	6.66	208%
	78.58	396.43	475.02	504%	64.91	143.49	83%

(b) 95% CO_2 reduction

availability of renewables in neighboring regions is often complementary so that transmission enables supply of load in more hours, reducing the need for thermal plants with low capacity factors.

During extreme weather events, the BIG WIRES Act allows for the import of power from neighboring regions, which lowers outages for a vast majority of regions. However, regions have to ensure that there is still sufficient domestic capacity to meet local demand. A high reliance on imports from other regions, when there are no extreme events, can cause more outages to occur during extreme events. Finally, more transmission, which enables better access to renewables, also lowers total system CO_2 emissions. The results are consistent across similar proposed minimum transmission requirement policies.

The findings highlight the value of interregional transmission, supporting the removal of barriers that prevent its construction. Policies like the BIG WIRES Act, which require regions to build interregional transmission, can help capture this value. As the costs of wind and solar generation continue to decline, making it economically sensible to build more of these technologies, it also makes economic sense to build complementary transmission infrastructure. Our model, which does not specifically optimize for reliability, demonstrates that this economic build-out of interregional transmission also mitigates the impact of extreme weather events. Additionally, even without strict decarbonization policies, increased interregional transmission reduces CO_2 emissions thereby contributing to climate goals. What these show is that whether a policy is in support of economic efficiency, grid reliability, or environmental sustainability, building interregional transmission is a key strategy. Even if priority is given to only one of these goals, policies that look to increase interregional transmission will simultaneously achieve the other benefits. Overall, interregional transmission is an essential part of a modern, resilient, and sustainable energy grid.

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A Transfer Capabilities and Transmission Line Investment Cost

Current transfer capabilities per line (Capacity column) and the investment cost per MW-yr ($/MW-yr column) for expanding the line can be found in Table 13. Current transfer capabilities are sourced from the EPA's Power Sector Modeling Platform v6 – 2021 Summer Reference Case (EPA, 2021). Transmission investment costs per MW-yr were sourced from Shi (2023). Shi's methodology involves using NREL REeDS' definition of zones called "p-regions" (see Figure 21). Each NREL REeDS p-region has a base cost ($/MW/mile) of building a transmission line that starts/ends in the p-region (see https://github.com/NREL/ReEDS-2.0; Ho et al., 2021). The p-region is converted to the zones in our model by the weighted area of overlap between the two. Distance between zones is measured by a straight line between centroids of two zones. Line loss is 0.01 per 100 miles. Transmission cost ($/MW/mile) between zones is the average of the two zones, then multiplied by the distance (miles) between the zones. Transmission cost is then annualized (4.4% WACC, 60-year capital recovery period (Gorman et al., 2019)).

The costs of transmission between p-regions are calculated as follows: For interregional transmission lines, an assumed voltage of either 345kV, 500kV, or 765kV is used based on the highest line voltage in the p-region from the Homeland Security Infrastructure project (HSIP, 2012). Each voltage class corresponds to a base capital cost of $2333/MW/mile, $1347/MW/mile, and $1400/MW/mile for 345kV, 500kV, and 765kV, respectively. The cost is scaled according to regional multipliers. The base cost and regional multipliers are taken from the Phase II Eastern Interconnection Planning Collaborative (EIPC) report (EIPC, 2015): (Vol 2, pp. 5-1 to 5-5: https://eipconline.com/phase-ii-documents).

We assume that intraregional transmission can be, at most, doubled. In a sensitivity analysis of this assumption (maximum x2, maximum x3, maximum x10, unlimited intraregional), the results shift to more renewables and increased cost savings brought by the BIG WIRES Act.

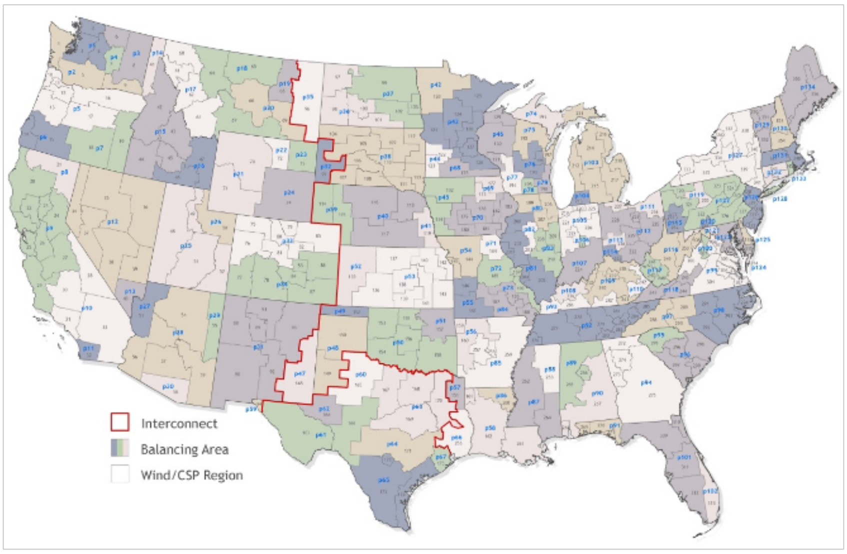


Figure 21: NREL REeDS p-regions (taken from Ho et al. (2021))

Table 13: Lines and Transfer Capability (in MW)

Line (Zone z_to_Zone z')	Region From	Region To	Capacity	$/MW-yr	Line (Zone z_to_Zone z')	Region From	Region To	Capacity	$/MW-yr
ERC_REST_to_ERC_WEST	Texas	Texas	5,529	12,493	NY_Z_A_to_PJM_PENE	New York	Mid-Atlantic	500	16,410
ERC_REST_to_SPP_WEST	Texas	Central	600	18,005	PJM_WMAC_to_PJM_EMAC	Mid-Atlantic	Mid-Atlantic	6,900	23,014
ERC_WEST_to_ERC_PHDL	Texas	Texas	3,332	9,413	PJM_WMAC_to_PJM_SMAC	Mid-Atlantic	Mid-Atlantic	780	31,679
ERC_WEST_to_SPP_WEST	Texas	Central	220	20,194	PJM_WMAC_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	-	23,837
FRCC_to_S_SOU	Florida	Southeast	3,600	23,751	PJM_WMAC_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	3,565	17,985
MIS_MAPP_to_MIS_MNWI	Midwest	Midwest	2,150	18,833	PJM_EMAC_to_PJM_SMAC	Mid-Atlantic	Mid-Atlantic	300	26,591
MIS_MAPP_to_SPP_WAUE	Midwest	Central	1,000	7,545	PJM_SMAC_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	1,100	27,217
MIS_IL_to_MIS_INKY	Midwest	Midwest	956	6,559	PJM_SMAC_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	1,200	23,363
MIS_IL_to_MIS_IA	Midwest	Midwest	-	12,072	PJM_West_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	4,800	15,665
MIS_IL_to_MIS_MIDA	Midwest	Midwest	716	14,149	PJM_West_to_PJM_COMD	Mid-Atlantic	Mid-Atlantic	980	23,488
MIS_IL_to_MIS_MO	Midwest	Midwest	3,400	6,153	PJM_West_to_PJM_ATSI	Mid-Atlantic	Mid-Atlantic	7,400	11,330
MIS_IL_to_PJM_West	Midwest	Mid-Atlantic	-	18,739	PJM_West_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	1,530	19,121
MIS_IL_to_PJM_COMD	Midwest	Mid-Atlantic	3,200	7,894	PJM_West_to_S_VACA	Mid-Atlantic	Southeast	1,219	17,700
MIS_IL_to_S_C_TVA	Midwest	Southeast	1,200	15,556	PJM_West_to_S_C_KY	Mid-Atlantic	Southeast	1,214	7,411
MIS_INKY_to_MIS_LMI	Midwest	Midwest	-	16,225	PJM_West_to_S_C_TVA	Mid-Atlantic	Southeast	2,119	19,794
MIS_INKY_to_PJM_West	Midwest	Mid-Atlantic	5,441	11,689	PJM_AP_to_PJM_ATSI	Mid-Atlantic	Mid-Atlantic	2,444	15,326
MIS_INKY_to_PJM_COMD	Midwest	Mid-Atlantic	2,044	10,763	PJM_AP_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	5,400	13,659
MIS_INKY_to_S_C_KY	Midwest	Southeast	2,245	8,583	PJM_AP_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	2,785	15,360
MIS_INKY_to_S_C_TVA	Midwest	Southeast	300	14,703	PJM_ATSI_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	-	23,806
MIS_IA_to_MIS_MIDA	Midwest	Midwest	1,616	2,765	PJM_Dom_to_S_VACA	Mid-Atlantic	Southeast	1,000	11,977
MIS_IA_to_MIS_MO	Midwest	Midwest	223	10,900	S_VACA_to_S_C_TVA	Southeast	Southeast	216	20,101
MIS_IA_to_MIS_WUMS	Midwest	Midwest	-	13,902	S_VACA_to_S_SOU	Southeast	Southeast	1,400	19,089
MIS_IA_to_MIS_MNWI	Midwest	Midwest	1,195	12,148	S_C_KY_to_S_C_TVA	Southeast	Southeast	764	13,332
MIS_IA_to_PJM_COMD	Midwest	Mid-Atlantic	-	10,729	S_D_AECI_to_S_C_TVA	Southeast	Southeast	-	23,120
MIS_IA_to_S_D_AECI	Midwest	Southeast	-	14,366	S_D_AECI_to_SPP_NEBR	Southeast	Central	-	25,834
MIS_IA_to_SPP_WAUE	Midwest	Central	-	18,503	S_D_AECI_to_SPP_N	Southeast	Central	1,130	16,108
MIS_MIDA_to_MIS_MO	Midwest	Midwest	716	11,934	S_D_AECI_to_SPP_WEST	Southeast	Central	1,172	18,363
MIS_MIDA_to_MIS_MNWI	Midwest	Midwest	-	12,200	S_D_AECI_to_SPP_WAUE	Southeast	Central	-	34,486
MIS_MIDA_to_PJM_COMD	Midwest	Mid-Atlantic	2,000	13,948	S_C_TVA_to_S_SOU	Southeast	Southeast	3,196	15,346
MIS_MIDA_to_S_D_AECI	Midwest	Southeast	-	15,237	SPP_NEBR_to_SPP_N	Central	Central	1,433	12,055
MIS_MIDA_to_SPP_NEBR	Midwest	Central	1,912	13,080	SPP_NEBR_to_SPP_WEST	Central	Central	-	24,082
MIS_MIDA_to_SPP_N	Midwest	Central	-	14,160	SPP_NEBR_to_SPP_WAUE	Central	Central	1,440	11,420
MIS_MIDA_to_SPP_WAUE	Midwest	Central	600	16,266	SPP_N_to_SPP_WEST	Central	Central	2,903	11,645
MIS_LMI_to_MIS_WUMS	Midwest	Midwest	-	12,033	SPP_N_to_SPP_SPS	Central	Central	469	19,046
MIS_LMI_to_PJM_West	Midwest	Mid-Atlantic	1,400	20,415	SPP_WEST_to_SPP_SPS	Central	Central	1,289	19,011
MIS_LMI_to_PJM_ATSI	Midwest	Mid-Atlantic	1,262	14,742	SPP_SPS_to_WECC_NM	Central	Southwest	610	12,448
MIS_MO_to_S_D_AECI	Midwest	Southeast	2,100	1,927	WEC_CALN_to_WECC_SCE	California	California	3,675	52,126
MIS_MO_to_SPP_N	Midwest	Central	300	14,417	WEC_CALN_to_WEC_BANC	California	California	2,750	11,013
MIS_WUMS_to_MIS_MNWI	Midwest	Midwest	1,480	12,639	WEC_CALN_to_WECC_NNV	California	Northwest	100	28,453
MIS_WUMS_to_PJM_COMD	Midwest	Mid-Atlantic	1,200	13,131	WEC_CALN_to_WECC_PNW	California	Northwest	3,675	54,715
MIS_MNWI_to_SPP_WAUE	Midwest	Central	2,000	14,648	WEC_LADW_to_WECC_SCE	California	California	3,750	13,977
MIS_WOTA_to_MIS_LA	Midwest	Midwest	1,200	11,717	WEC_LADW_to_WECC_NNV	California	Northwest	3,883	22,452
MIS_WOTA_to_SPP_WEST	Midwest	Central	-	26,035	WEC_LADW_to_WECC_UT	California	Northwest	1,400	50,774
MIS_AMSO_to_MIS_D_MS	Midwest	Midwest	200	14,794	WEC_LADW_to_WECC_PNW	California	Northwest	2,858	78,676
MIS_AMSO_to_MIS_LA	Midwest	Midwest	1,699	14,404	WEC_LADW_to_WECC_AZ	California	Southwest	468	46,156
MIS_AR_to_MIS_LA	Midwest	Midwest	1,732	21,170	WEC_SDGE_to_WECC_SCE	California	California	1,273	24,746
MIS_AR_to_S_D_AECI	Midwest	Southeast	1,039	19,737	WEC_SDGE_to_WECC_AZ	California	Southwest	1,168	34,905
MIS_AR_to_S_C_TVA	Midwest	Southeast	2,143	21,225	WEC_SDGE_to_WECC_IID	California	Southwest	150	13,016
MIS_AR_to_SPP_N	Midwest	Central	-	27,619	WECC_SCE_to_WECC_SNV	California	Northwest	2,814	16,731
MIS_AR_to_SPP_WEST	Midwest	Central	792	17,680	WECC_SCE_to_WECC_AZ	California	Southwest	1,968	37,252
MIS_D_MS_to_MIS_LA	Midwest	Midwest	1,732	13,498	WECC_SCE_to_WECC_IID	California	Southwest	600	30,099
MIS_D_MS_to_S_C_TVA	Midwest	Southeast	1,949	21,318	WECC_MT_to_WECC_ID	Northwest	Northwest	325	17,413
MIS_D_MS_to_S_SOU	Midwest	Southeast	94	23,067	WECC_MT_to_WECC_PNW	Northwest	Northwest	2,000	31,882
MIS_LA_to_S_SOU	Midwest	Southeast	797	34,673	WECC_MT_to_WECC_WY	Northwest	Northwest	400	22,311
MIS_LA_to_SPP_WEST	Midwest	Central	905	24,409	WECC_ID_to_WECC_NNV	Northwest	Northwest	350	20,628
NENG_CT_to_NENGREST	Northeast	Northeast	2,950	35,071	WECC_ID_to_WECC_UT	Northwest	Northwest	680	22,132
NENG_CT_to_NY_Z_G-I	Northeast	New York	600	17,030	WECC_ID_to_WECC_PNW	Northwest	Northwest	2,850	22,020
NENG_CT_to_NY_Z_K	Northeast	New York	760	19,019	WECC_ID_to_WECC_WY	Northwest	Northwest	1,500	23,989
NENGREST_to_NENG_ME	Northeast	Northeast	2,000	56,012	WECC_NNV_to_WECC_UT	Northwest	Northwest	235	17,742
NENGREST_to_NY_Z_F	Northeast	New York	800	22,290	WECC_NNV_to_WECC_PNW	Northwest	Northwest	300	30,536
NENGREST_to_NY_Z_D	Northeast	New York	-	34,272	WECC_SNV_to_WECC_UT	Northwest	Northwest	250	18,343
NY_Z_C&E_to_NY_Z_F	New York	New York	3,250	16,549	WECC_SNV_to_WECC_AZ	Northwest	Southwest	4,785	15,079
NY_Z_C&E_to_NY_Z_G-I	New York	New York	2,150	20,475	WECC_UT_to_WECC_CO	Northwest	Southwest	650	21,833
NY_Z_C&E_to_NY_Z_B	New York	New York	1,300	15,411	WECC_UT_to_WECC_WY	Northwest	Northwest	1,600	23,085
NY_Z_C&E_to_NY_Z_D	New York	New York	1,600	22,002	WECC_UT_to_WECC_AZ	Northwest	Southwest	250	22,653
NY_Z_C&E_to_PJM_PENE	New York	Mid-Atlantic	755	28,946	WECC_UT_to_WECC_NM	Northwest	Southwest	350	28,515
NY_Z_F_to_NY_Z_G-I	New York	New York	3,475	18,327	WECC_CO_to_WECC_WY	Southwest	Northwest	1,400	19,611
NY_Z_G-I_to_NY_Z_J	New York	New York	4,450	18,393	WECC_CO_to_WECC_NM	Southwest	Southwest	614	21,063
NY_Z_G-I_to_NY_Z_K	New York	New York	1,290	22,730	WECC_AZ_to_WECC_NM	Southwest	Southwest	2,400	18,922
NY_Z_J_to_NY_Z_K	New York	New York	175	19,249	WECC_AZ_to_WECC_IID	Southwest	Southwest	255	26,366
NY_Z_K_to_PJM_EMAC	New York	Mid-Atlantic	660	49,594					
NY_Z_A_to_NY_Z_B	New York	New York	1,930	8,844					

B Fuel Costs

Fuel costs are sourced from EIA AEO 2022 for the year 2035. The individual zones are matched to the AEO regions through PowerGenome.

Table 14: Fuel Costs

Fuel	AEO Region	BIG WIRES Act Region/s	Fuel Name	Price ($/MMBtu)
coal	pacific	California, Northwest	pacific_reference_coal	1.97
	mountain	Northwest, Southwest	mountain_reference_coal	1.32
	new_england	Northeast	new_england_reference_coal	2.00
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_coal	2.39
	middle_atlantic	Mid-Atlantic	middle_atlantic_reference_coal	2.22
	west_south_central	Central, Midwest, Texas	west_south_central_reference_coal	1.73
	east_south_central	Southeast	east_south_central_reference_coal	1.83
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_coal	1.57
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_coal	1.80
natural gas	pacific	California, Northwest, Southwest	pacific_reference_naturalgas	4.01
	mountain	Northwest, Southwest	mountain_reference_naturalgas	4.33
	new_england	Northeast	new_england_reference_naturalgas	3.86
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_naturalgas	4.21
	middle_atlantic	Mid-Atlantic, New York	middle_atlantic_reference_naturalgas	3.25
	west_south_central	Central, Midwest, Texas	west_south_central_reference_naturalgas	3.67
	east_south_central	Southeast	east_south_central_reference_naturalgas	3.91
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_naturalgas	4.07
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_naturalgas	3.51
uranium	pacific	California, Northwest, Southwest	pacific_reference_uranium	0.72
	mountain	Northwest, Southwest	mountain_reference_uranium	0.72
	new_england	Northeast	new_england_reference_uranium	0.72
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_uranium	0.72
	middle_atlantic	Mid-Atlantic, New York	middle_atlantic_reference_uranium	0.72
	west_south_central	Central, Midwest, Texas	west_south_central_reference_uranium	0.72
	east_south_central	Southeast	east_south_central_reference_uranium	0.72
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_uranium	0.72
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_uranium	0.72

C Policies

C.1 Inflation Reduction Act

Table 15 shows our assumption on IRA (Inflation Reduction Act) Tax Credits per applicable technology. The Tax Credit Amounts/Percentages are obtained by getting the average of the lowest possible and highest possible tax credits that can be obtained. These values are taken from https://www.whitehouse.gov/cleanenergy/clean-energy-tax-provisions/. The tax monetization penalty is taken from the same assumptions in NREL's 2022 Standard Scenarios Report. These values are lower than the typical 33% tax monetization penalties assumed in existing models because of provisions in the IRA that make it easier to monetize tax credits (Gagnon et al., 2023).

Table 15: Inflation Reduction Act Tax Credit Assumptions

Technology	Tax Credit Type	Units	Amount	Tax Monetization Penalty	Final Tax Credit
Solar Photovoltaic	Production Tax Credit	$/MWh	9	10%	8.1
Onshore Wind Turbine	Production Tax Credit	$/MWh	9	10%	8.1
Batteries	Investment Tax Credit	Percentage	18%	10%	16.20%
Offshore Wind Turbine	Investment Tax Credit	Percentage	18%	10%	16.20%
Nuclear	Investment Tax Credit	Percentage	18%	10%	16.20%
Natural Gas CCS	Captured CO2 Incentive	$/MT	85	7.50%	78.63

C.2 Offshore Wind Mandates

We incorporate offshore wind mandates based on existing Bills/Acts in applicable states. These were obtained from NREL REeDS Assumptions in Table 3-21 (Ho et al., 2021) and from the California Energy Commission (CEC, 2022) and then assigned to the GenX zones based on the overlap of the zone with the state/s. The summarized information on the offshore wind mandates used in our model is found in Table 16. Any difference between the Mandate and the GenX minimum builds is due to the specified calculation in PowerGenome, which determines the maximum possible capacity of offshore wind in a zone. For California, the mandate is for 3.5GW of offshore wind generation capacity to be built by 2030 and 25GW by 2045. The 2035 mandate in the table is the linear extrapolation between these two values. The total minimum amount of offshore wind capacity is then 35GW by 2035.

Table 16: Offshore Wind Mandates

State	Bill/Act	Mandate (MW)	Implementation Year	GenX Zones	GenX Min Builds (MW)
Maryland	Senate Bill 516	1,200	2030	PJM_DOM	4,801
	Maryland Offshore Wind Energy Act of 2013	368	2023		
Virginia	Virginia Clean Economy Act	5,200	2035		
California	California Assembly Bill 525	10,200	2030	WECC_PNW WEC BANC WEC_CALN WEC_LADW	10,200
New Jersey	Executive Order No. 92	7,500	2035	PJM_EMAC	7,332
Connecticut	House Bill 7156	2,000	2030	NENG_REST	6,000
Massachusetts	Massachusets Energy Diversity Act	4,000	2027		
New York	Climate Leadership and Community Protection Act	9,000	2035	NY_Z_J	6,236

D Alternative Interregional Transmission Build Algorithm

In the main text, we used the Greedy Dual Algorithm as the heuristic that determines where transmission will be built to satisfy the MITC requirement. We provide alternative heuristics in this section, namely the *Iterative Dual Algorithm* and the *Greedy Algorithm.* In both algorithms, δ_r and d_l are defined similarly as in section 2.4.1.

The Iterative Dual Algorithm iteratively increases the maximum line reinforcement of a line with the most negative dual by a small amount each time and re-evaluates the solution. The heuristic stops once all regions meet the MITC.

Algorithm 3. ***Iterative Dual Algorithm***

Let $\epsilon > 0$ be a user input on how much each line will be increased for every iteration

1. *Solve the problem and obtain the duals d_l of each line*
2. *Obtain $l^* = \arg\max(l|d_l$ and $\delta_r > 0$ for $l \in \hat{\mathcal{L}}_r)$*
3. *Set $R_l' = R_l + \epsilon$*
4. *If $\exists \delta_r > 0$, go back to step 1. Otherwise, stop.*

Another alternative algorithm is the *Greedy Algorithm.* The Greedy Algorithm works in the same way as the Greedy Dual Algorithm, except it uses the current interregional transmission capacity ($\hat{c}_l$) between regions instead of the dual as the basis for calculating the proportion of additional transmission capacity that gets allocated to a line.

Algorithm 4. ***Greedy Algorithm***

1. *Obtain* $\delta_r^* = \max\{\delta_r\}$

2. *Set* $R_l' = R_l + \frac{|\hat{c}_l|\delta_r^*}{\sum_{l \in \hat{\mathcal{L}}_r} |\hat{c}_l|}$ *for each* $l \in \hat{\mathcal{L}}_r$

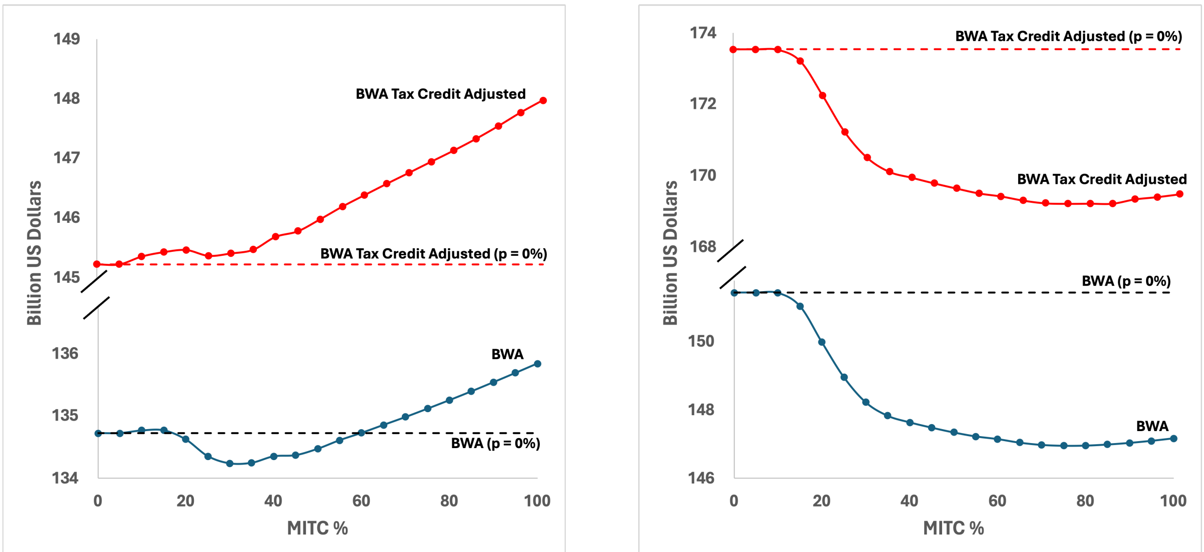
3. *Set* $R_l = R_l'$ *for each* $l \in \hat{\mathcal{L}}_r$

4. *Recalculate* $\delta_r = MITC_r - \sum_{l \in \hat{\mathcal{L}}_r} (\hat{c}_l + R_l)$ *for all* r

5. *If* $\exists \delta_r > 0$, *go back to step 1. Otherwise, stop.*

E Alternative Cost Calculations: IRA Tax Credit Accounting

This section presents alternative cost curves on the basis of tax credit accounting. In the main text, we presented cost curves that are net of tax credits obtained through the Inflation Reduction Act. Figures 22a and 22b compare the BWA (unadjusted, net of tax credits, similar to the main text) and the BWA tax credit adjusted cost curves. Deciding on whether to use the adjusted or unadjusted system cost depends on how a "system" is defined. In our case, we examine the US power sector independent of other sectors. An alternative definition includes the total US federal system, which would subsume the power sector. This encompassing system provides a budget for tax credits, so the costs for tax credits applied to the power sector would still be incurred by the federal system. The build-outs that we expect will still occur, but the overall cost would be higher.



(a) Current Policies

(b) 95% CO_2 reduction

Figure 22: Comparison of annual system cost between Adjusted and Unadjusted Tax Credits

F Cost, Revenue, and Producer Surplus Allocation per Region

We allocate cost and revenue to each region. We assume that costs and revenue values associated with a generation facility are assigned to a region where the facility is located. We compare the costs, revenues, and producer surplus (i.e., revenue - cost) between the BWA and No BWA scenarios excluding transmission investments, with aggregated results found in Tables 17a, 17b, and 17c.

Table 17: Cost, Revenue, and Producer Surplus per Region (Million \$)

	Current Policies				95% CO_2 reduction			
	No BWA	BWA	Difference	Percentage Change	No BWA	BWA	Difference	Percentage Change
California	7,809	7,611	(198)	(3%)	7,224	7,273	48	1%
Florida	8,781	8,454	(328)	(4%)	11,124	8,338	(2,785)	(25%)
Northeast	5,197	5,078	(119)	(2%)	5,810	5,588	(223)	(4%)
Midwest	21,749	22,613	864	4%	23,677	24,498	820	3%
Northwest	6,853	6,447	(406)	(6%)	8,636	8,446	(191)	(2%)
New York	5,830	6,224	394	7%	6,460	7,517	1,058	16%
Mid-Atlantic	31,100	31,946	846	3%	35,580	34,352	(1,228)	(3%)
Southeast	23,816	20,956	(2,861)	(12%)	28,141	26,341	(1,800)	(6%)
Central	6,643	7,239	596	9%	7,017	7,285	267	4%
Southwest	5,122	4,583	(539)	(11%)	4,870	4,341	(529)	(11%)
Texas	11,172	11,175	3	0%	12,057	12,005	(52)	0%

(a) Cost per Region

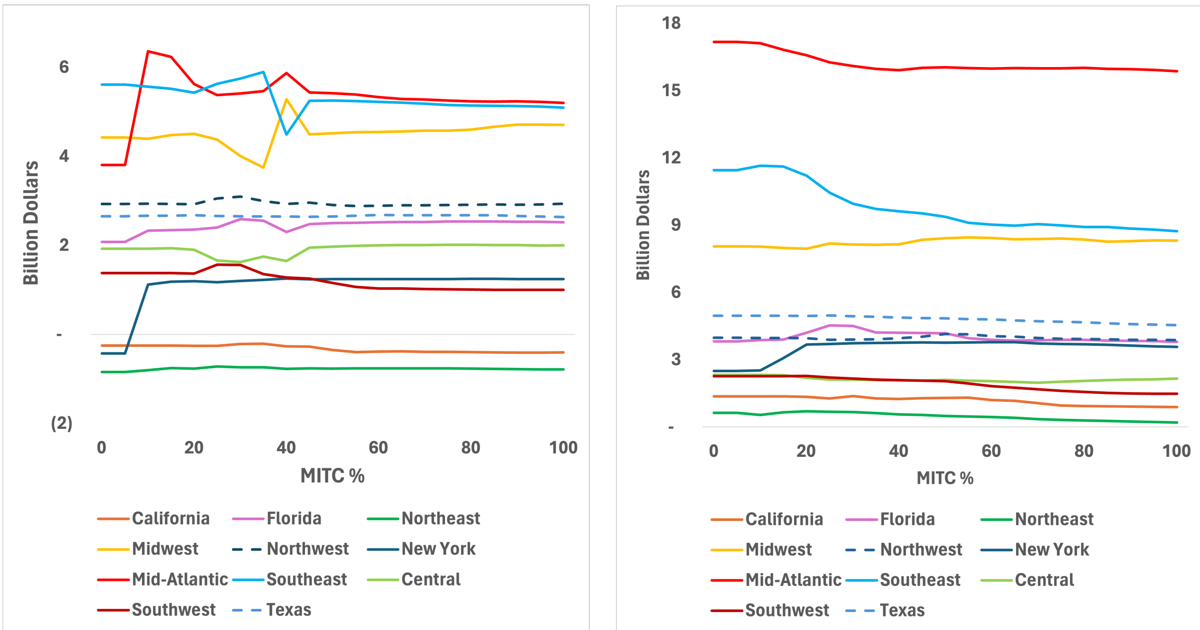
	Current Policies				95% CO_2 reduction			
	No BWA	BWA	Difference	Percentage Change	No BWA	BWA	Difference	Percentage Change
California	7,555	7,395	(159)	(2%)	8,589	8,641	52	1%
Florida	10,860	11,043	183	2%	14,940	12,838	(2,102)	(14%)
Northeast	4,352	4,339	(13)	0%	6,436	6,252	(184)	(3%)
Midwest	26,173	26,616	443	2%	31,729	32,628	900	3%
Northwest	9,786	9,540	(246)	(3%)	12,610	12,347	(263)	(2%)
New York	5,401	7,427	2,026	38%	8,957	11,250	2,293	26%
Mid-Atlantic	34,907	37,359	2,453	7%	52,752	50,451	(2,301)	(4%)
Southeast	29,430	26,702	(2,728)	(9%)	39,589	36,300	(3,289)	(8%)
Central	8,565	8,864	299	3%	9,332	9,394	62	1%
Southwest	6,501	6,139	(361)	(6%)	7,137	6,502	(634)	(9%)
Texas	13,825	13,826	1	0%	17,011	16,937	(73)	0%

(b) Revenue per Region

	Current Policies				95% CO_2 reduction			
	No BWA	BWA	Difference	Percentage Change	No BWA	BWA	Difference	Percentage Change
California	(255)	(216)	39	15%	1,365	1,369	4	0%
Florida	2,078	2,589	511	25%	3,817	4,500	683	18%
Northeast	(844)	(739)	106	13%	626	664	38	6%
Midwest	4,425	4,004	(421)	(10%)	8,051	8,131	79	1%
Northwest	2,933	3,093	161	5%	3,973	3,901	(72)	(2%)
New York	(429)	1,203	1,632	380%	2,497	3,733	1,235	49%
Mid-Atlantic	3,806	5,413	1,607	42%	17,173	16,100	(1,073)	(6%)
Southeast	5,614	5,747	133	2%	11,449	9,959	(1,489)	(13%)
Central	1,922	1,625	(297)	(15%)	2,314	2,109	(205)	(9%)
Southwest	1,379	1,557	178	13%	2,267	2,161	(106)	(5%)
Texas	2,654	2,651	(2)	0%	4,954	4,933	(21)	0%

(c) Producer Surplus per Region

Figures 23a and 23b show the regional producer surplus at different p values.



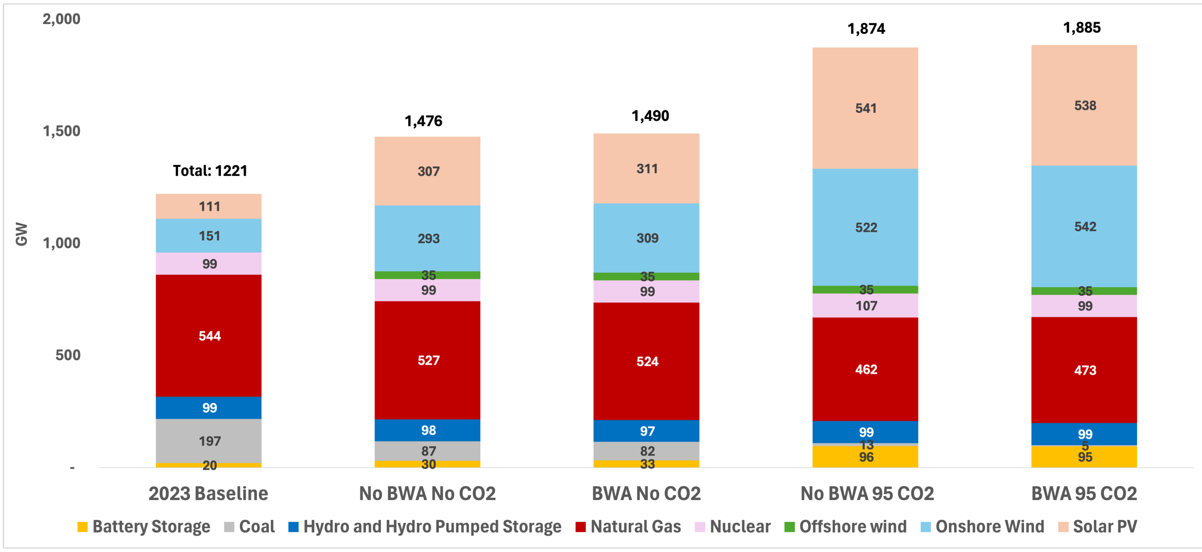
(a) Current Policies

(b) 95% CO_2 reduction

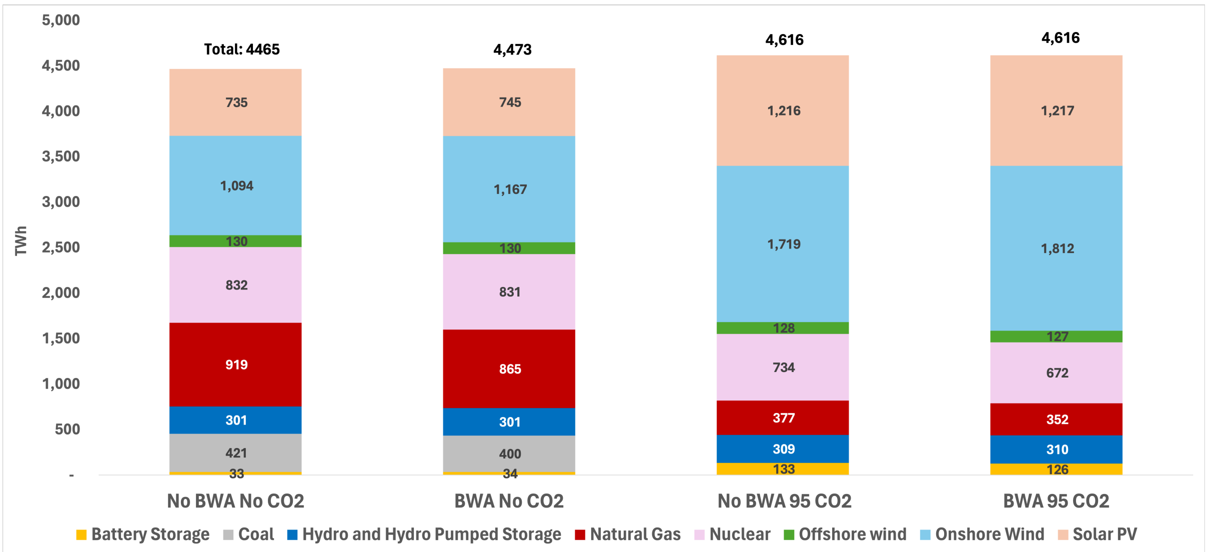
Figure 23: Regional Producer Surplus per MITC %

G Capacity and Generation Mix

Figures 24a and 24b show the capacity and generation mix aggregated for the entire US for each scenario. The following subsections disaggregate this for the Current Policies and 95% reduction scenarios.



(a) US System Capacity Mix



(b) US System Generation Mix

Figure 24: Capacity and Generation Mix per Scenario

G.1 Regional Capacity and Generation Mix for the Current Policies scenario

Figures 25 and 26 show the capacity and generation mix per region for the Current Policies scenario.

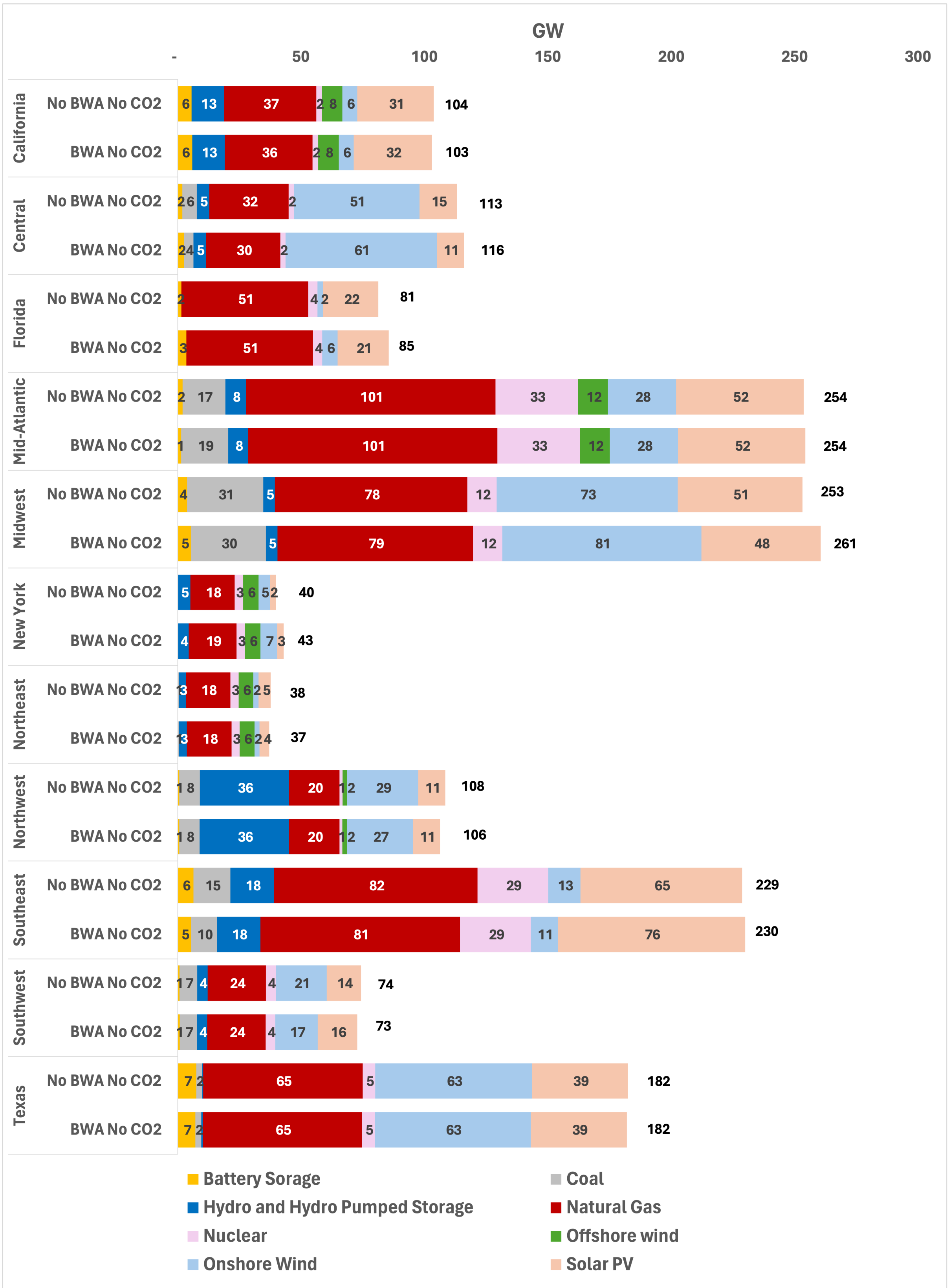


Figure 25: Regional Capacity Mix in the Current Policies scenario

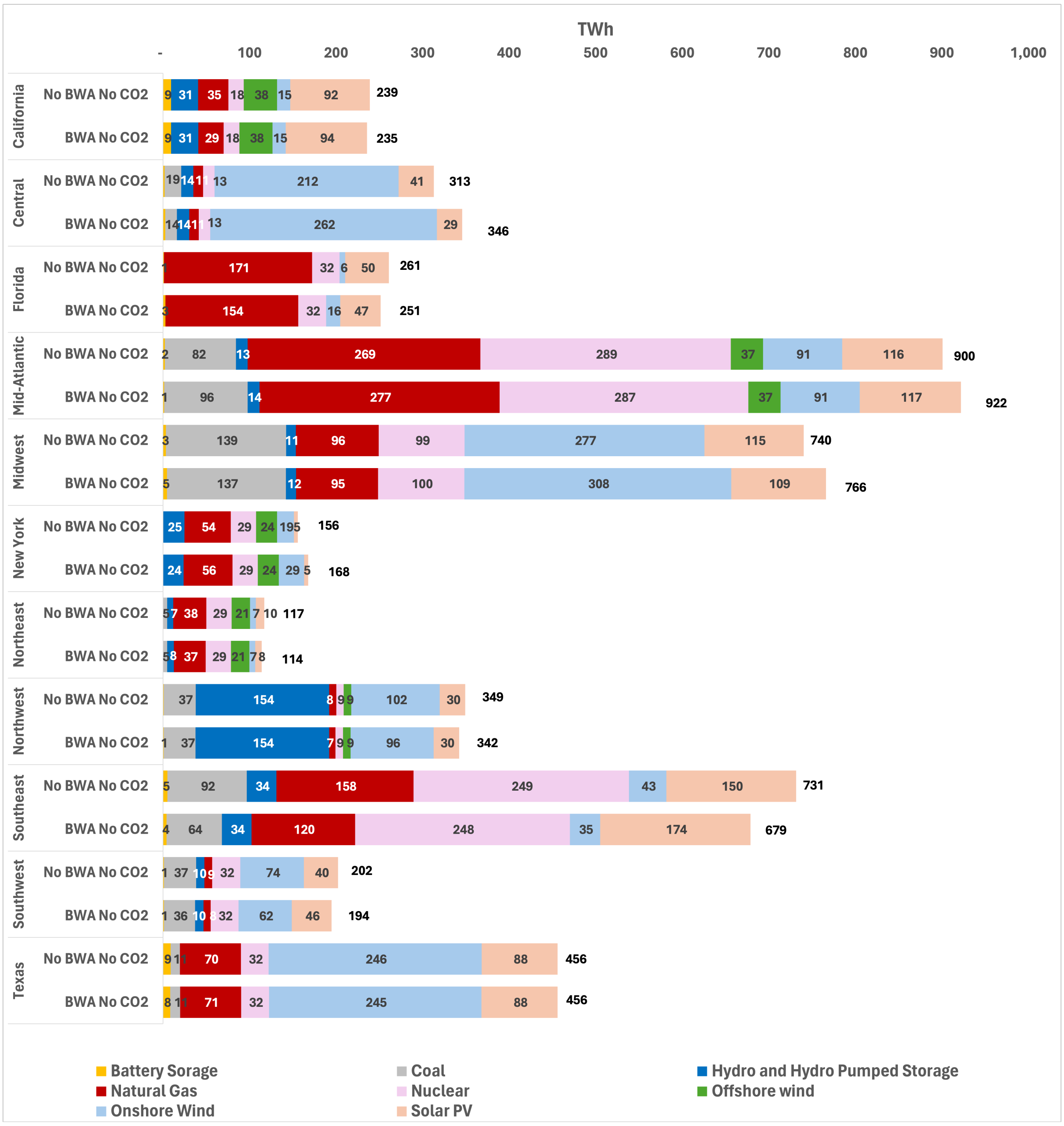


Figure 26: Regional Generation Mix in the Current Policies scenario

G.2 Regional Capacity and Generation Mix for the 95% CO_2 Reduction scenario

Figures 27 and 28 show the capacity and generation mix per region for the 95% CO_2 Reduction scenario.

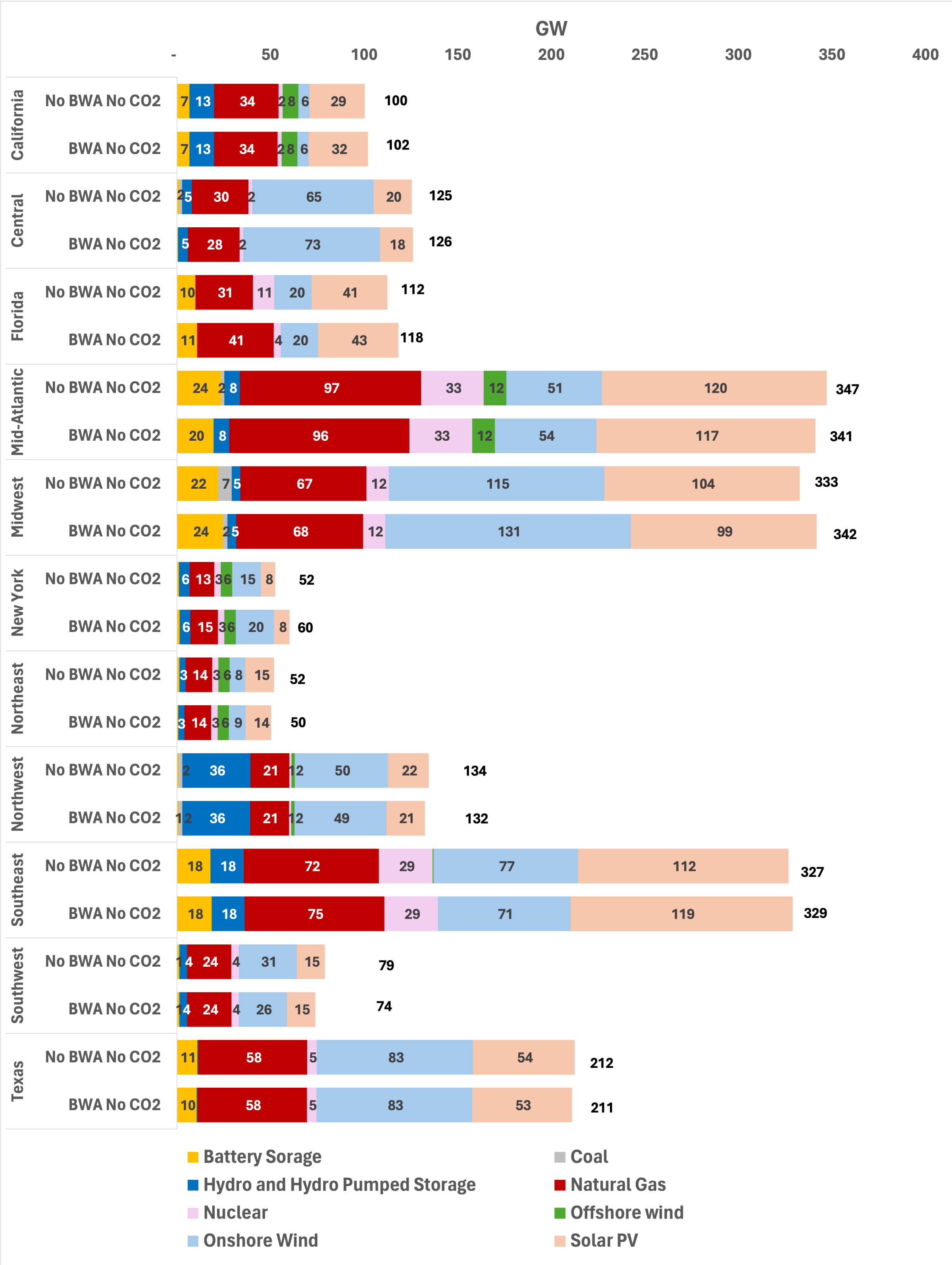


Figure 27: Regional Capacity Mix in the No 95% CO_2 Reduction scenario

H Capacity Factors for Intraregional transmission lines in the Current Policies scenario with BWA

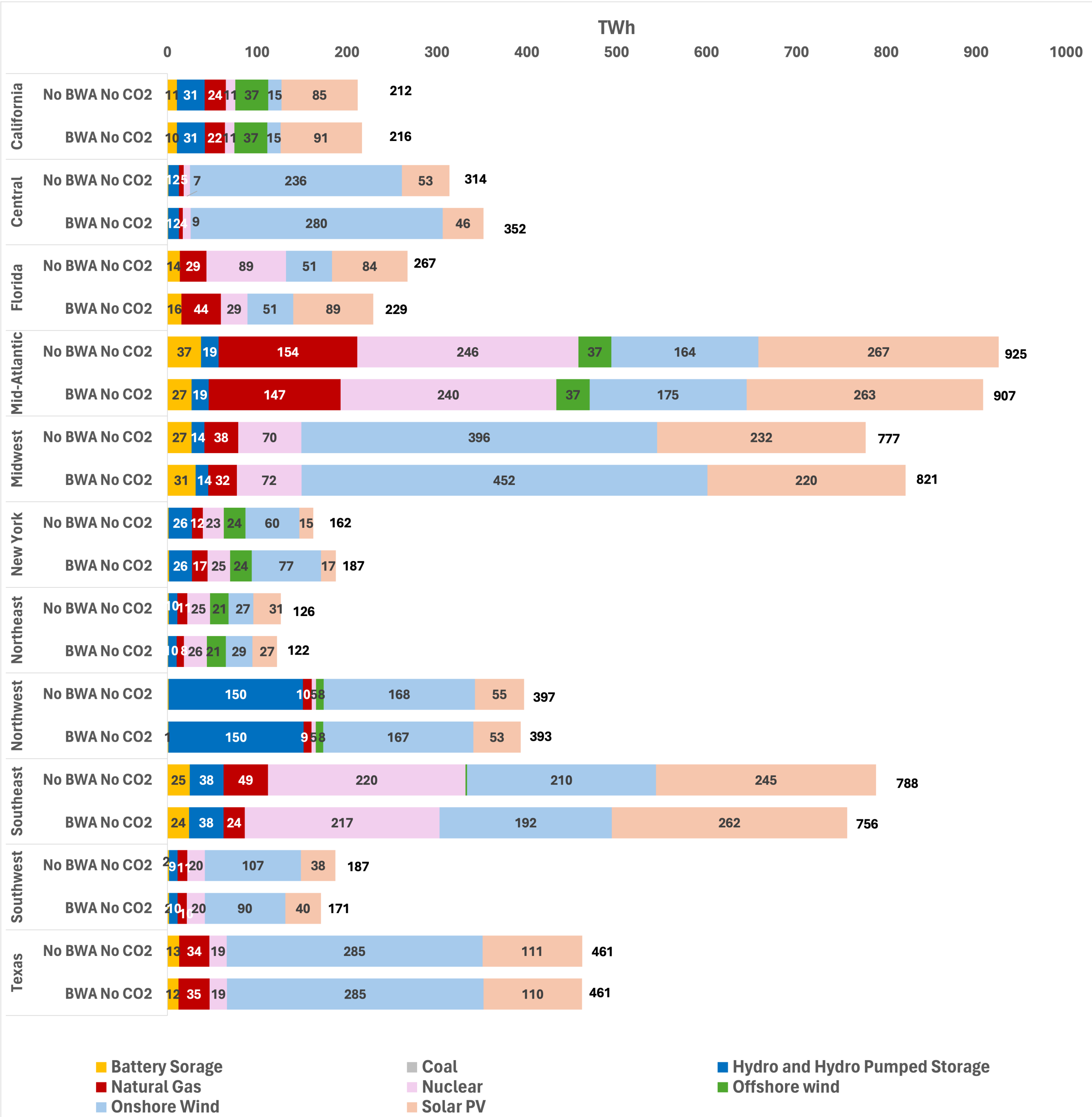


Figure 28: Regional Generation Mix in the 95% CO_2 Reduction scenario

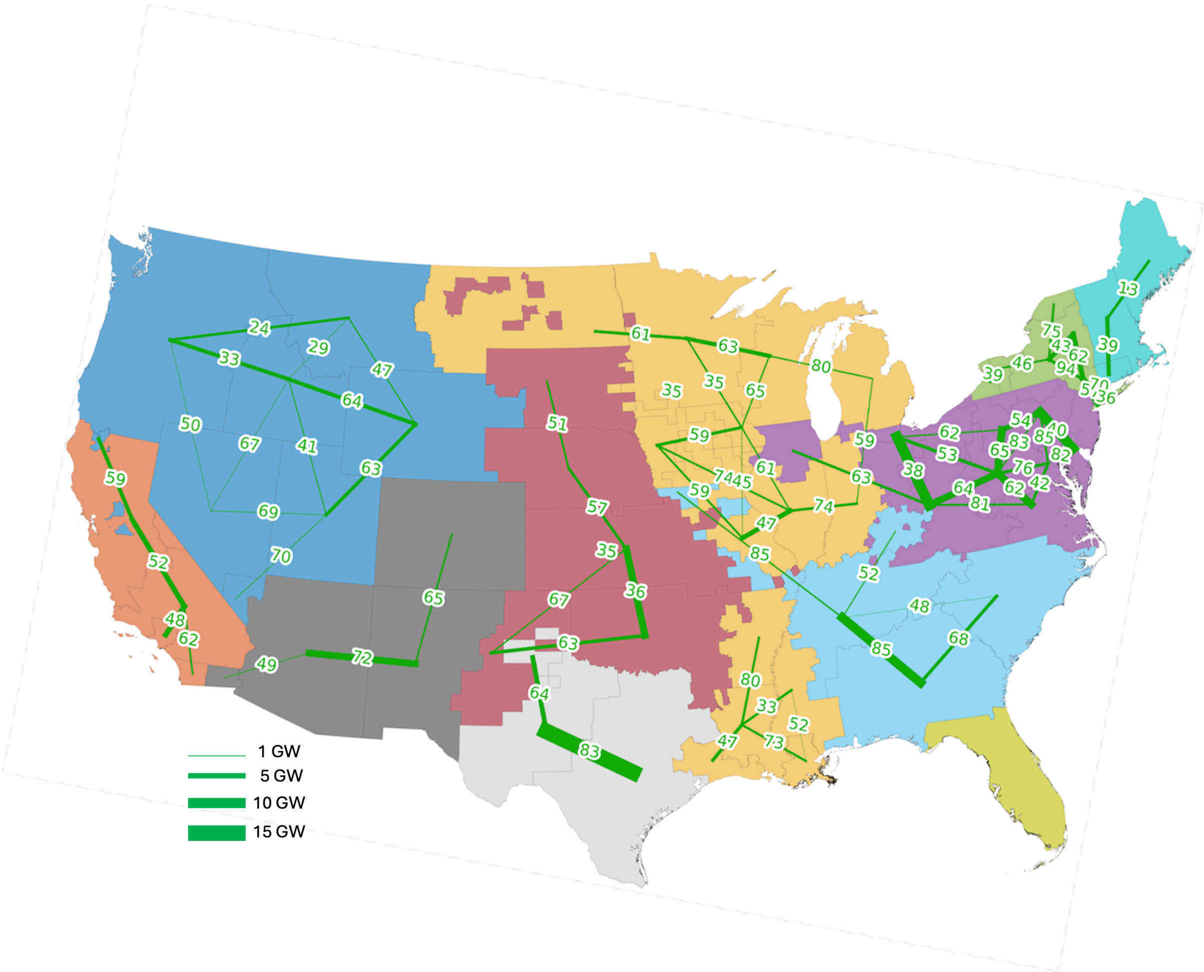


Figure 29: Average Capacity Factors for Intraregional Lines

Contact.

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MIT CEEPR
Center for Energy and
Environmental Policy Research

MIT Center for Energy and
Environmental Policy Research
Massachusetts Institute of Technology
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
USA

ceepr.mit.edu

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