Federal Policy Options for Improving Grid Reliability and Reducing Costs with Transmission

by Audun Botterud, Christopher R. Knittel, John E. Parsons, Juan Ramon L. Senga, and S. Drew Story

Authors are listed in alphabetical order.

January 2025

Executive Summary

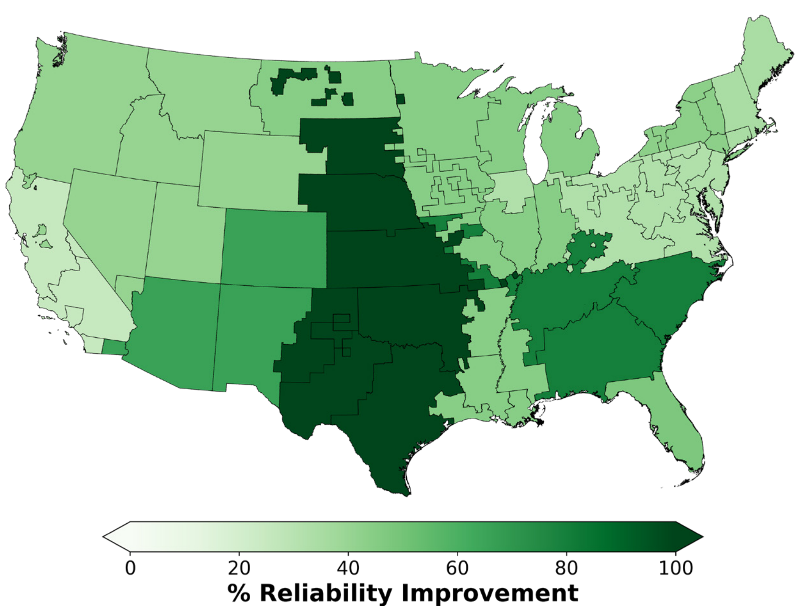
Improving the U.S. electric power system would provide many benefits, whether the goal is to keep up with projected demand growth and spur economic development, to lower household energy costs, to bolster the system's resilience to natural or nefarious disruptions, or to achieve certain environmental outcomes. In particular, increasing transmission between different regions in the power grid would dramatically improve grid reliability during extreme weather events, lead to cost savings in the electric power system, and reduce air pollution and greenhouse gas emissions.

Researchers at the Massachusetts Institute of Technology developed a grid modeling tool to empower policymakers and regional transmission planners to evaluate a variety of electric power system policies. Using this model, they evaluated four unique policy options for increasing interregional transmission:

1. Establishing a **uniform minimum transfer capability requirement** for all transmission planning regions
2. Providing a **transmission investment tax credit** for interregional and intraregional projects
3. Combining a **uniform minimum transfer capability requirement with a transmission investment tax credit**
4. Authorizing the Federal Energy Regulatory Commission (FERC) to determine **unique, region-specific minimum transfer capability requirements that optimize for system-wide cost and reliability.**

This report explains the projected impacts of each policy choice in terms of improvements to grid reliability, cost savings, and reductions in air pollution and greenhouse gas emissions. As policymakers and stakeholders evaluate transmission policy options, the tools and resources developed by researchers at MIT are available to perform additional analysis.

Improving Grid Reliability Through Region-Specific Minimum Transfer Capability Requirements



Cover Photo: iStock.com/Sundry Photography

Introduction

As policymakers and stakeholders consider federal policy options for improving the nation's electric power infrastructure, the diversity of objectives and priorities for doing so remains broad. Whether the goal is to keep up with projected demand growth and spur economic development, to lower household energy costs, to bolster the system's resilience to natural or nefarious disruptions, or to achieve certain environmental outcomes, improving the electric power system would provide benefits to just about everyone. The transmission component of the electric power system holds the key to unlocking these benefits. In particular, increasing transmission between different regions in the power grid would dramatically improve grid reliability during extreme weather events, lead to cost savings in the power system, and reduce air pollution and greenhouse gas emissions.

Across the US, the average hourly difference in energy prices between regions was as high as $58/megawatt hour (MWh) in 2022, meaning some regions are paying much more for electricity than others.[1] This large price disparity also indicates that the system is not operating at its lowest cost. One would expect regions with high costs to attempt to capture potential savings for ratepayers by connecting to neighboring regions with lower costs, thereby importing cheaper electricity. It would also be expected that regions with lower-cost electricity would be eager to export their electricity to generate additional revenues. Beyond the cost savings, it is commonly accepted that a more interconnected grid would result in improvements in grid reliability, given the ability to import power during temporary outages or to meet unanticipated demand. But in reality, large transmission projects are very rarely being built, indicating that some other non-monetary friction is outweighing both the monetary and reliability benefits. Without additional policy interventions to spur new interregional transmission projects, the multifaceted friction that currently blocks such projects will continue to defer the potential benefits of a better-connected grid.

1 US Department of Energy, National Transmission Needs Study, October 2023, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

Policy Options

Researchers at the Massachusetts Institute of Technology developed a grid modeling tool to empower policymakers and regional transmission planners to evaluate a variety of electric power system policies. This tool, a capacity expansion model, finds the lowest-cost version of the grid that satisfies a policymaker's particular objectives, such as satisfying a desired load growth for a particular region, achieving a certain amount of grid reliability, or producing a particular generation mix. To provide more realistic projections, we incorporated into the tool a "non-monetary friction" as an attempt to account for the difficulty of adding transmission that goes beyond the pure costs of building and operating it.[2] By using publicly available data on generation, load, and technology cost projections, this modeling tool is capable of exploring individual policy options and combinations of policy options, and it can project the impacts of those policies on the electric power system at a designated point in the future.

Using this model, four unique policy options for increasing interregional transmission were evaluated for their impacts on overall transmission builds, improvements to grid reliability, cost savings, and reductions in air pollution and greenhouse gas emissions:

1. Establishing a **uniform minimum transfer capability requirement** for all transmission planning regions
2. Providing a **transmission investment tax credit** for interregional and intraregional projects
3. Combining a **uniform minimum transfer capability requirement with a transmission investment tax credit**
4. Authorizing the Federal Energy Regulatory Commission (FERC) to determine **unique, region-specific minimum transfer capability requirements that optimize for system-wide cost and reliability.**

We use the Integrated Planning Model (IPM) regions published by the US Environmental Protection Agency as model zones. These zones are then grouped into 11 regions that closely resemble the regions identified in FERC Order No. 1000. Despite most of Texas not being subject to FERC jurisdiction, our analysis incorporated Texas to demonstrate the various impacts on reliability, cost, and emissions reduction that would occur if Texas voluntarily participated in the four policy options.

Each region is expected to respond differently to the four policy options presented, based on its natural resources, geography, population, and the characteristics of its neighboring regions. These differences in response are described in subsequent sections and are also detailed in the Appendix.

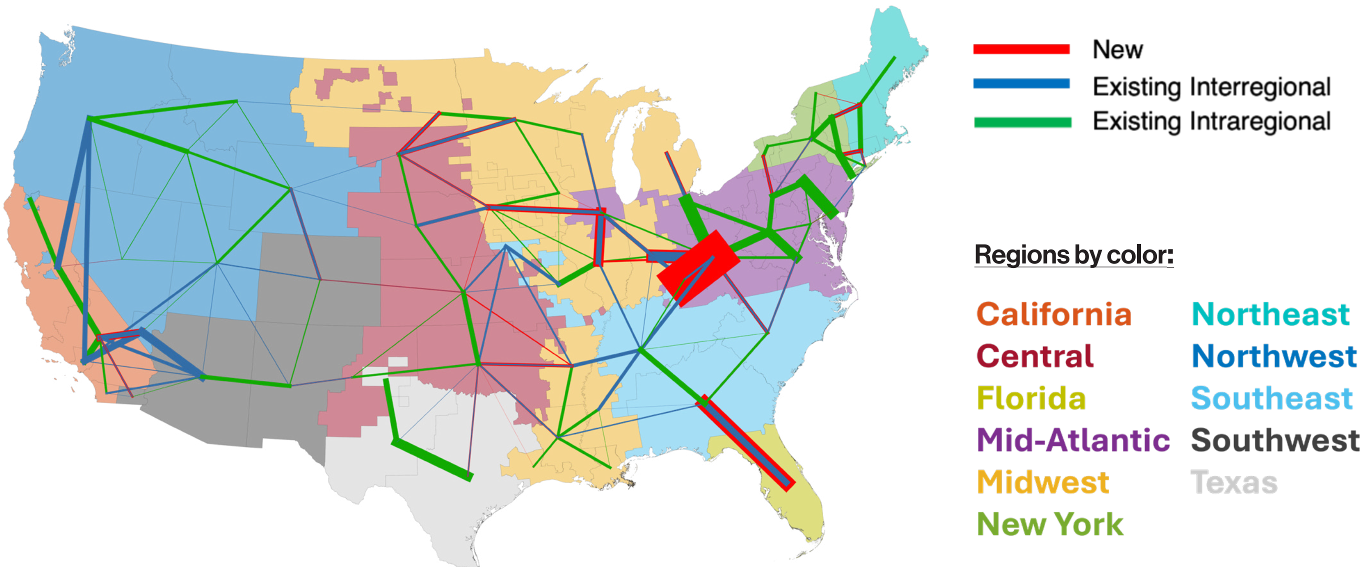
Projected Effects on Transmission Builds

A **uniform minimum transfer capability requirement** is a straightforward and blunt policy option. It requires each transmission planning region to reach and maintain the ability to send or receive a certain amount of power to and from its neighboring regions. This policy option would likely improve reliability, but at costs that would vary significantly by region, since some regions are already well-connected to their neighbors, and since the non-monetary friction described previously makes it more costly to build transmission projects between some regions. Our analysis indicates that imposing a uniform minimum transfer capability requirement of 30% of a region's peak load (for regions with two or more neighboring regions) or 15% (for regions with only one neighboring region) would result in 51GW of new interregional transmission being built across the US. For some regions, like the Southwest, this represents a small increase from the region's current transfer capability of 27% of peak load. For other regions, like the Mid-Atlantic, a 30% transfer capability requirement represents a drastic increase from the region's existing 12% transfer capability. In Figure 1, the red lines show how much interregional transmission would need to be built between each region to satisfy such a uniform minimum transfer capability requirement. The thickness of the lines is proportional to the transmission capacity.

2 To produce a highly simplified value of the "non-monetary friction" preventing transmission projects from being built, we used the average hourly difference in energy prices observed between regions to deduce the value currently being forfeited by the lack of interregional transmission. We then calibrated the model to reflect the forfeited value as a minimum of the "non-monetary friction" that must be overcome for a transmission project to be built.

Figure 1: How a Uniform Minimum Transfer Capability Requirement Would Increase Transmission Builds

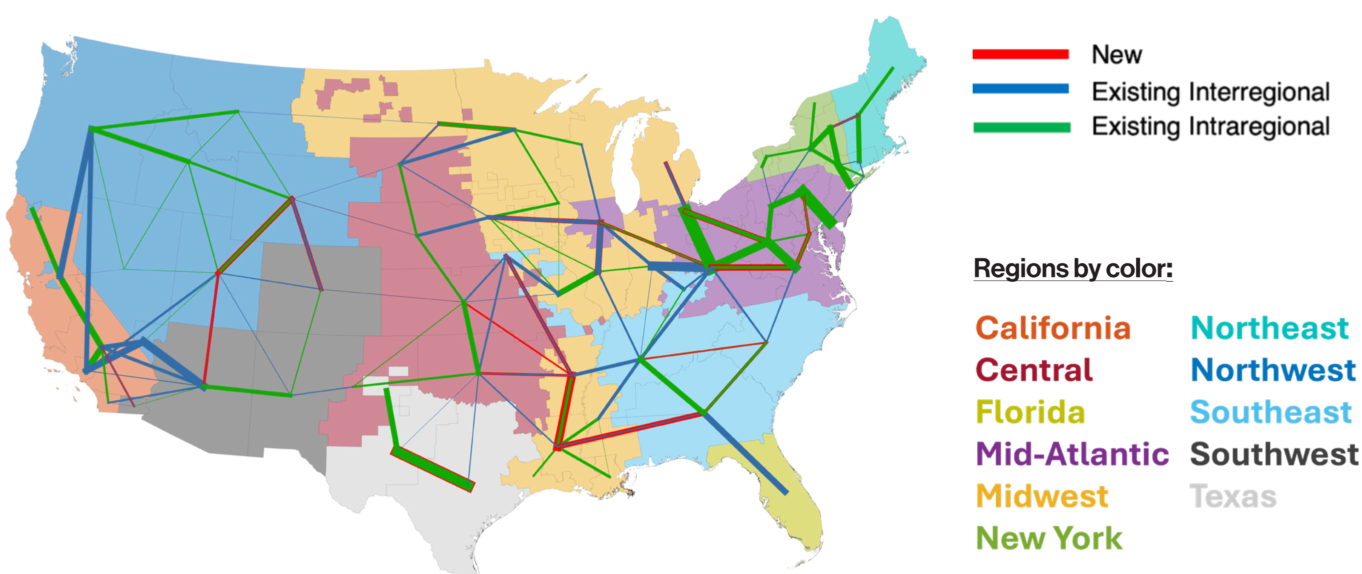
Lines in red show transmission builds that would result from a 30% minimum transfer capability requirement.



A **transmission investment tax credit** is a policy option that would reduce the investment cost and encourage some new transmission projects without mandating that all regions build. As a result, some regions may not see any reliability improvement if the region does not capitalize on the tax credit. In our analysis, we modeled a 30% investment tax credit that applies to both interregional and intraregional transmission projects. Such a policy results in 11GW of new interregional transmission and 14GW of new intraregional transmission. The projects are concentrated in areas like the Midwest, where a 30% reduction in cost is enough to tip the scales for projects that otherwise do not pencil out. In Figure 2, the red lines show the projected increases in interregional and intraregional transmission projects that would be built in response to a 30% transmission investment tax credit.

Figure 2: How a Transmission Investment Tax Credit Would Increase Transmission Builds

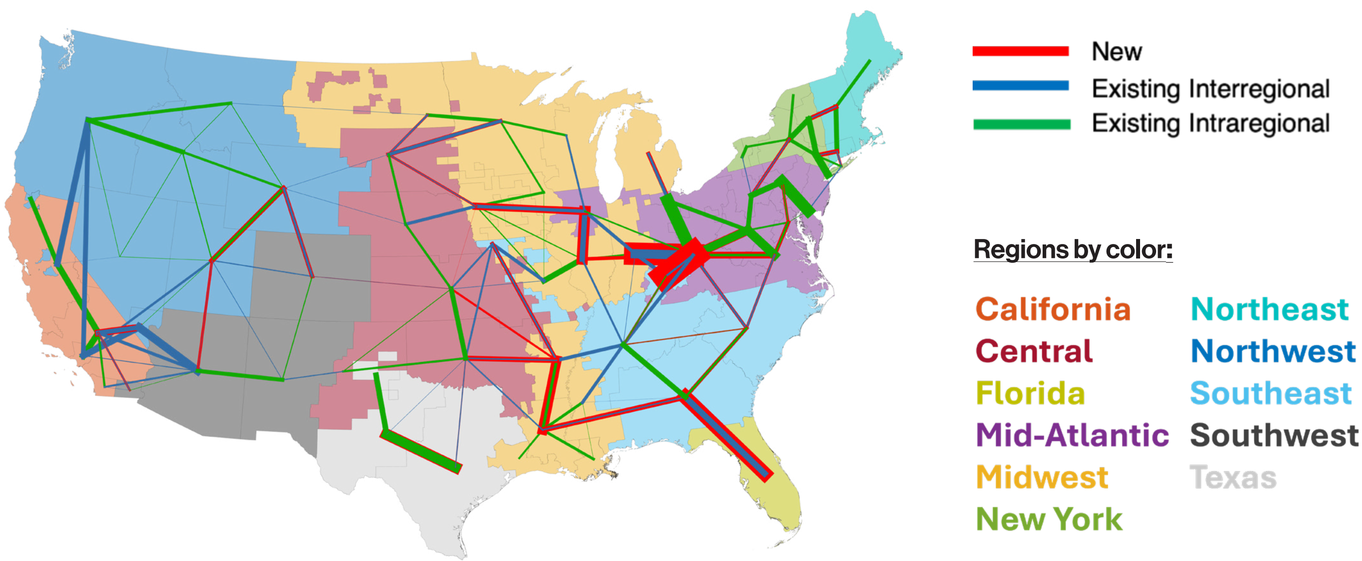
Lines in red show transmission builds that would result from a 30% investment tax credit for interregional and intraregional transmission projects.



Combining a **uniform minimum transfer capability requirement with a transmission investment tax credit** ensures a certain amount of transmission is built and guarantees some reliability benefits, while also subsidizing the costs. In our analysis, we modeled the 30% minimum transfer capability requirement described above combined with a 30% transmission investment tax credit. This combination results in 57GW of new interregional transmission and 14GW of new intraregional transmission. The greatest percentage increases in transfer capability occur in the Northeast and in New York, while the magnitude of installed transmission is greatest in the Midwest, Mid-Atlantic, and Southeast regions. In Figure 3, the red lines show projected increases in interregional and intraregional transmission projects built in response to combining a 30% minimum transfer capability requirement with a 30% transmission investment tax credit.

Figure 3: How a Uniform Minimum Transfer Capability Requirement Combined with a Transmission Investment Tax Credit Would Increase Transmission Builds

Lines in red show transmission builds that would result from a uniform minimum transfer capability requirement of 30% combined with a 30% investment tax credit.

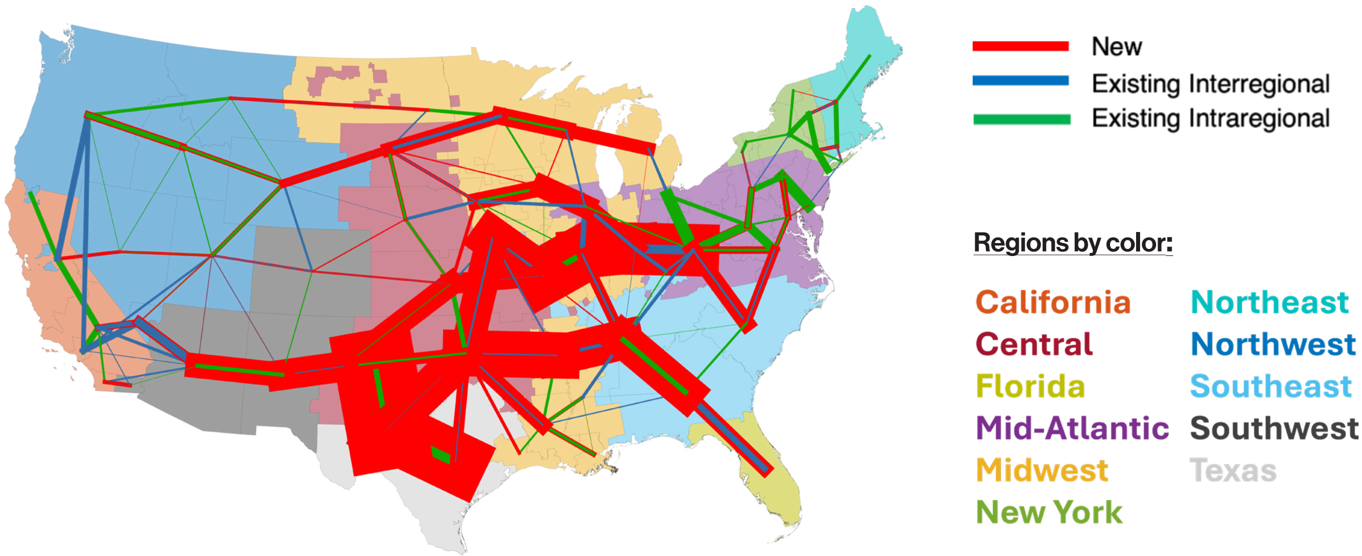


If FERC had the authority to evaluate and account for the regional differences in costs of generation, fuel, and transmission projects in order to determine **unique, region-specific minimum transfer capability requirements that optimize for system-wide cost and regional reliability (C&R)**, this policy option could produce the most reliable grid of the four policy options and do so at the lowest cost. In our analysis, we assumed that this new authority for FERC would be accompanied by other policy interventions to eliminate the non-monetary friction plaguing the system, whether that be in the form of improving permitting and siting processes, including the alignment of state and federal processes, or creative ways to address "NIMBY-ism." This assumption reflects a benchmark scenario, useful only for the purposes of highlighting the scale of relative benefits that are currently unrealized.

For this approach, we used the cost-optimization model to project where investments in generation and transmission would be made based solely on cost and without the additional non-monetary friction included in the other policy options. We then performed a simulation of an extreme weather event to test the cost-optimized grid for reliability. Any region that did not exhibit a 25% increase in reliability during the simulated extreme weather event was then evaluated at increasing levels of a minimum transfer capability requirement until the region saw at least a 25% improvement in reliability. For many regions, like the Central region and the Midwest region, even optimizing the grid for cost alone built enough interregional transmission so as to yield high improvements in reliability. For four regions (California, the Northeast, New York, and the Mid-Atlantic), the cost-optimized grid did not surpass the threshold of a 25% improvement in reliability. Instead, these regions were assigned the lowest minimum transfer capability requirement that would satisfy this reliability threshold. This cost-and-reliability-optimized approach could result in 264GW of new interregional transmission (a 331% increase) and 231GW of new intraregional transmission (a 178% increase). In Figure 4, the lines in red show projected increases in interregional and intraregional transmission projects built in response to unique, region-specific minimum transfer capability requirements that optimize for cost and reliability.

Figure 4: How Region-Specific Minimum Transfer Capability Requirements Would Increase Transmission Builds

The red lines show transmission builds that would result if FERC had the authority to determine unique, region-specific minimum transfer capability requirements that optimize for cost and reliability.



Grid Reliability

A primary benefit of increasing interregional transmission is a grid that is more reliable and resilient. Across the country, the electric power system experiences disruptions and suffers damages due to extreme weather events like polar vortexes, heatwaves, wildfires, and hurricanes. These extreme weather events knock out power generation, cause unanticipated spikes in demand, and damage transmission and distribution. In cases of insufficient generation, whether due to offline power generation or excessive demand, households will experience power loss if the affected regions are unable to import sufficient power.

> *A primary benefit of increasing interregional transmission is a grid that is more reliable and resilient.*

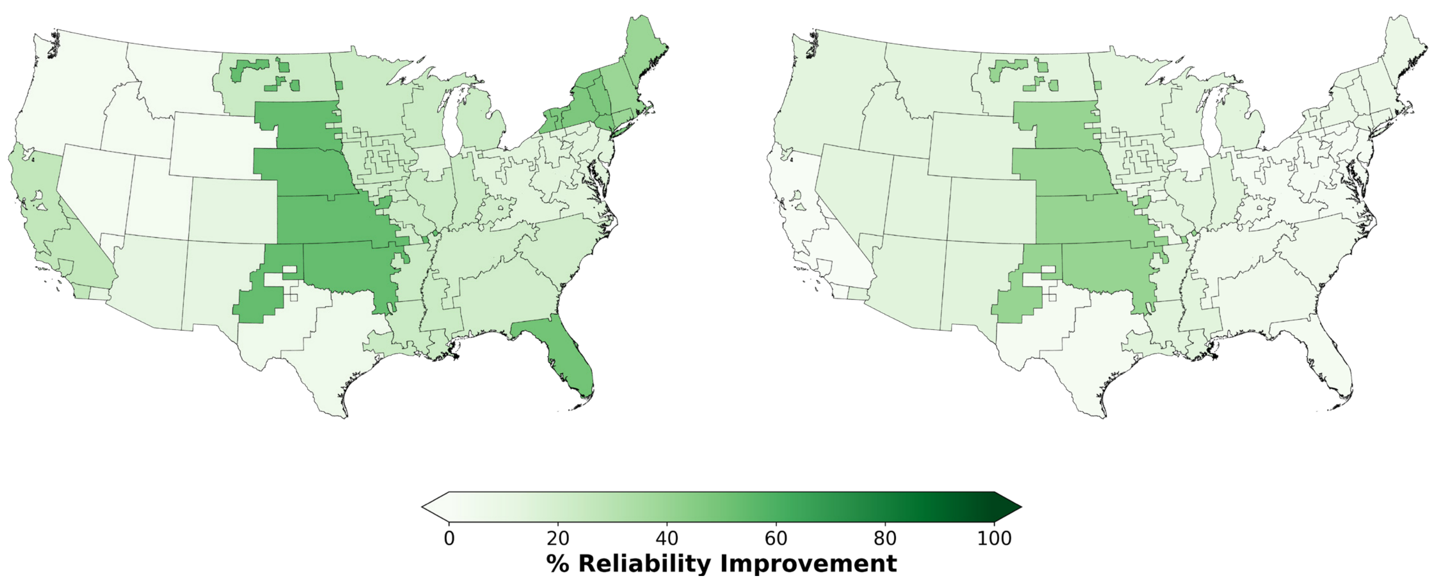
Each of the four policy options of interest was evaluated for reductions in household power outages during a simulated extreme weather event similar in magnitude to Winter Storm Uri, a polar vortex from 2021 that caused hundreds of deaths, millions of power outages, and billions of dollars in damage. In this simulation, a singular affected region would experience outages in 50% of its natural gas plants, 46% of its wind generation, 43% of its coal-fired power plants, 21% of its nuclear generation, and 7% of its solar photovoltaic generation, if such resources exist in that region. These values represent the effects to the generation mix in Texas during Winter Storm Uri. Simulating this type of extreme weather cannot evaluate all aspects of grid reliability, but it can expose vulnerabilities in the grid that policymakers may wish to address.

With the uniform 30% minimum transfer capability requirement, the average reduction in household power outages is 20%, but the regional value ranges from 3% in the Northwest region to 53% in the Central region. Those regions that respond to the policy by heavily investing in generation see the greatest benefits in reliability from this policy option. The map on the left in Figure 5 shows the relative improvements in reliability projected to occur as a result of a uniform 30% minimum transfer capability requirement.

Since roughly 50% less transmission is built as a result of the 30% transmission investment tax credit than as a result of the uniform 30% minimum transfer capability requirement, the reduction in power outages is less pronounced, with an average reduction in household power outages of 6%. Only the Central region, with a 39% reduction in outages, sees improvement greater than 15%. Household outages in California are actually projected to increase by 3% under this policy, likely due to the region retiring generation in response to the policy and relying on power imports even on "blue sky" days. Those regions with greater generation resources see the greatest improvements in reliability from this policy option. The map on the right in Figure 5 shows the relative improvements in reliability projected to occur as a result of a 30% transmission investment tax credit.

Figure 5: Improving Grid Reliability Through a 30% Uniform Minimum Transfer Capability Requirement or a 30% Transmission Investment Tax Credit

More new transmission capability is built in response to the minimum transfer capability requirement (shown in the map on the left below) than in response to the tax credit (shown in the map on the right below), so reliability increases more.

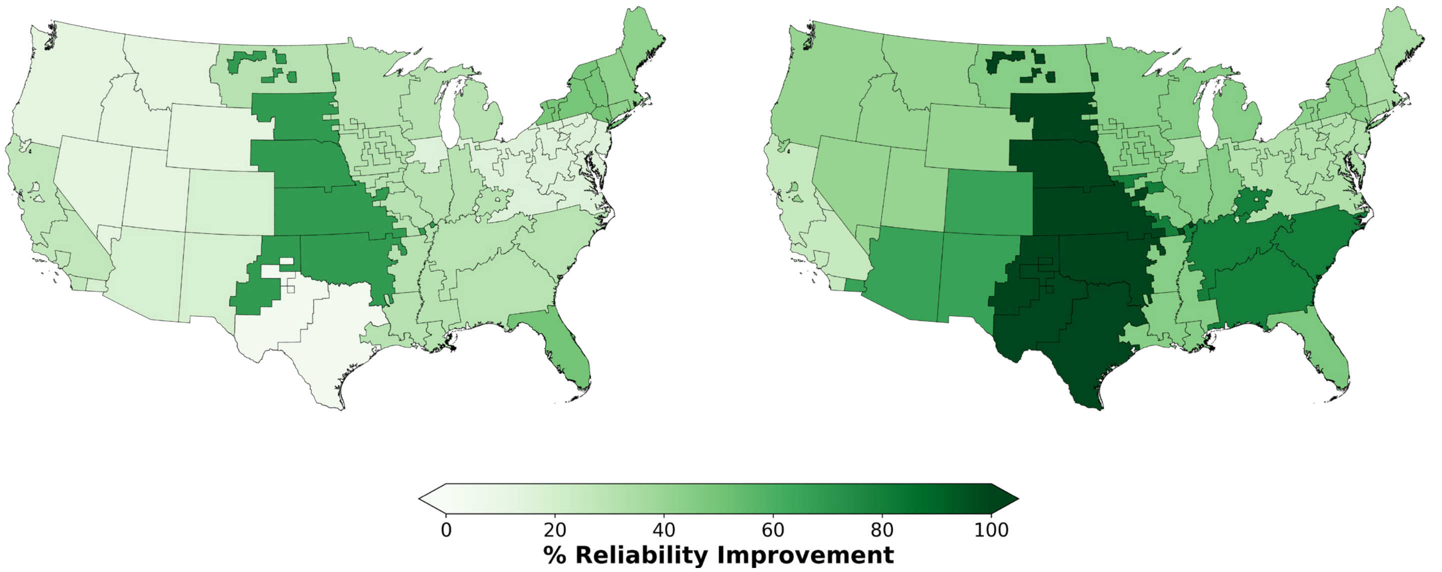


When the 30% minimum transfer capability requirement is combined with the 30% transmission investment tax credit, the average reduction in household power outages increases to 25%, but these benefits range from 13% in the Northwest region to 69% in the Central region. The map on the left in Figure 6 shows the relative improvements in reliability projected to occur as a result of combining a 30% minimum transfer capability requirement with a 30% transmission investment tax credit.

Implementing unique, region-specific minimum transfer capability requirements optimized for cost with at least a 25% reduction in household outages yields the most reliable grid of the four policy options, with an average reduction in household outages of 51%. The map on the right in Figure 6 shows the relative improvements in reliability projected to occur as a result of implementing unique, region-specific minimum transfer capabilities optimized for cost and with at least a 25% reduction in household outages.

Figure 6: Improving Grid Reliability Either by Combining a Uniform Minimum Transfer Capability and an Investment Tax Credit or Through Region-Specific Requirements

The map below on the left shows the relative improvements in reliability projected to occur as a result of combining a 30% minimum transfer capability requirement with a 30% transmission investment tax credit. Implementing region-specific minimum transfer capability requirements (shown in the map on the right below) yields the most reliable grid of the four policy options.



In some regions, optimizing only for cost is enough to warrant large investments in transmission, well beyond the amount needed to produce a 25% improvement in reliability. This is true for the Central region, where it is most cost-effective to pair those investments in transmission with complementary investments in generation. Not only does the Central region benefit from a much higher transfer capability for exporting its surplus power, but the investments in generation and transmission would be so great that the region could completely avoid all of the household outages that would occur during a Winter Storm Uri-type extreme weather event.

For other regions, like the Southeast and Midwest regions, it is more cost-effective to supplement their investments in transmission by retiring some of their own generation and importing power to replace it. This also requires an increase in transfer capability. Both of these shifts make these regions more resilient to the types of extreme weather events that knock out generation or produce unanticipated increases in demand, and their reduction in household outages is 80% and 44%, respectively.

In some regions, optimizing only for cost is enough to warrant large investments in transmission, well beyond the amount needed to produce a 25% improvement in reliability.

For still other regions, optimizing only for cost would leave the grid too vulnerable to these types of extreme weather events. Instead, determining the lowest-cost option that yields a specified reduction in household outages can balance both objectives. California and the Mid-Atlantic region are two such regions that would need to be assigned a 45% minimum transfer capability requirement to achieve this improvement in reliability, as optimizing only for cost would result in the retiring of too many generation assets without enough investment in new transmission to compensate. As a result, the reduction in household outages in these regions changes from –5% to 25% for California, and from 12% to 32% for the Mid-Atlantic region.

New York and the Northeast region would each need to be assigned a 20% minimum transfer capability requirement because these regions do not have much financial incentive to invest in transmission or new generation. Optimizing only for cost would not alter their respective regional grids much, but it would leave over 3 million households without power during a Winter Storm Uri-type event. Even the modest 20% minimum transfer capability requirement changes the extent by which household outages are reduced from 8% to 43% for New York, and from 1% to 35% for the Northeast region.

Table 1 shows the reduction in household outages in each region as a result of each of the four policy options, and Table 2 provides more details on transfer capability by region if optimized for cost and reliability.

Table 1: How Much Each of the Policy Options Would Reduce Household Outages During a Simulated Extreme Weather Event, By Region

Each of the four policy options of interest was evaluated for reductions in household power outages during a simulated extreme weather event. Regions marked with an asterisk are those for which the cost-optimal outcome would not improve reliability above our threshold of 25%.

	30% Minimum Transfer	30% Transmission ITC	30% Minimum Transfer and 30% Transmission ITC	C&R Optimized
California*	27%	-3%	26%	25%
Central	53%	39%	69%	100%
Florida	50%	3%	50%	47%
Mid-Atlantic*	14%	2%	16%	32%
Midwest	23%	14%	30%	44%
New York*	48%	9%	49%	43%
Northeast*	39%	9%	42%	35%
Northwest	3%	13%	13%	40%
Southeast	21%	5%	30%	80%
Southwest	11%	12%	17%	66%
Texas	6%	1%	3%	99%
National Average Reduction in Household Outages	20%	6%	25%	51%

Table 2: Regional Transfer Capabilities Optimized for Cost and Reliability

The following table contains the unique, region-specific minimum transfer capability requirement for each region that is cost-optimized with a minimum reliability improvement of 25%. Note that even for those regions with large increases in transfer capability, these values represent the cost-optimal outcome. Regions marked with an asterisk are those for which the cost-optimal outcome (listed in parentheses) would not improve reliability above our threshold of 25%.

	Existing Transfer Capability	C&R-Optimized Transfer Capability
California*	27%	45% (28%)
Central	6%	230%
Florida	7%	15%
Mid-Atlantic*	23%	45% (22%)
Midwest	34%	124%
New York*	12%	26% (14%)
Northeast*	12%	20% (8%)
Northwest	15%	45%
Southeast	19%	68%
Southwest	27%	92%
Texas	1%	30%

Cost Savings

Increased transmission lowers the cost of the electric power system in most cases by connecting regions with abundant energy resources to regions with expensive or scarce energy resources. This increased access provides opportunity for some regions to export energy and generate revenues, while providing other regions with the flexibility to reduce their fuel costs or avoid building expensive natural gas peaker plants. Incorporating the harder-to-quantify benefits of improved reliability and reduced pollution would make the calculations even more favorable for increasing transmission, but the costs described in this section are limited to the construction as well as operations and maintenance (O & M) of the electric power system, which includes both generation and transmission assets. The cost projections also include an assumption that existing clean electricity production tax credits (PTCs) remain available until 2035. On the following page, Table 3 summarizes the effects of the four policy options on total system cost, and Figure 7 details the effects of the four policy options on system component costs. (Additional information about these effects by region can be found in the Appendix.)

While the uniform 30% minimum transfer capability requirement leads to a buildout of 51GW of interregional transmission, it increases total system cost by only $34M (0.02% increase over the cost of the status quo grid). Subsidizing interregional and intraregional transmission projects with a 30% transmission ITC results in a buildout of 25GW and reduces total system cost by $562M (0.4%). When the 30% minimum transfer capability requirement is combined with the 30% transmission ITC, 71 GW of new transmission would be built, and the total system cost would be reduced by $566M (0.4%).

The grid optimized for cost and reliability could see up to $7.3B in total system cost reductions (5.4% savings from the cost of the status quo grid). As shown in Figure 7, even with large investments in new generation (~$5B) and transmission (~$7B), the vast majority of the cost reductions comes from avoided fuel costs and reduced maintenance (~$15B).

Table 3: How Each of the Four Policy Options Would Affect System Cost

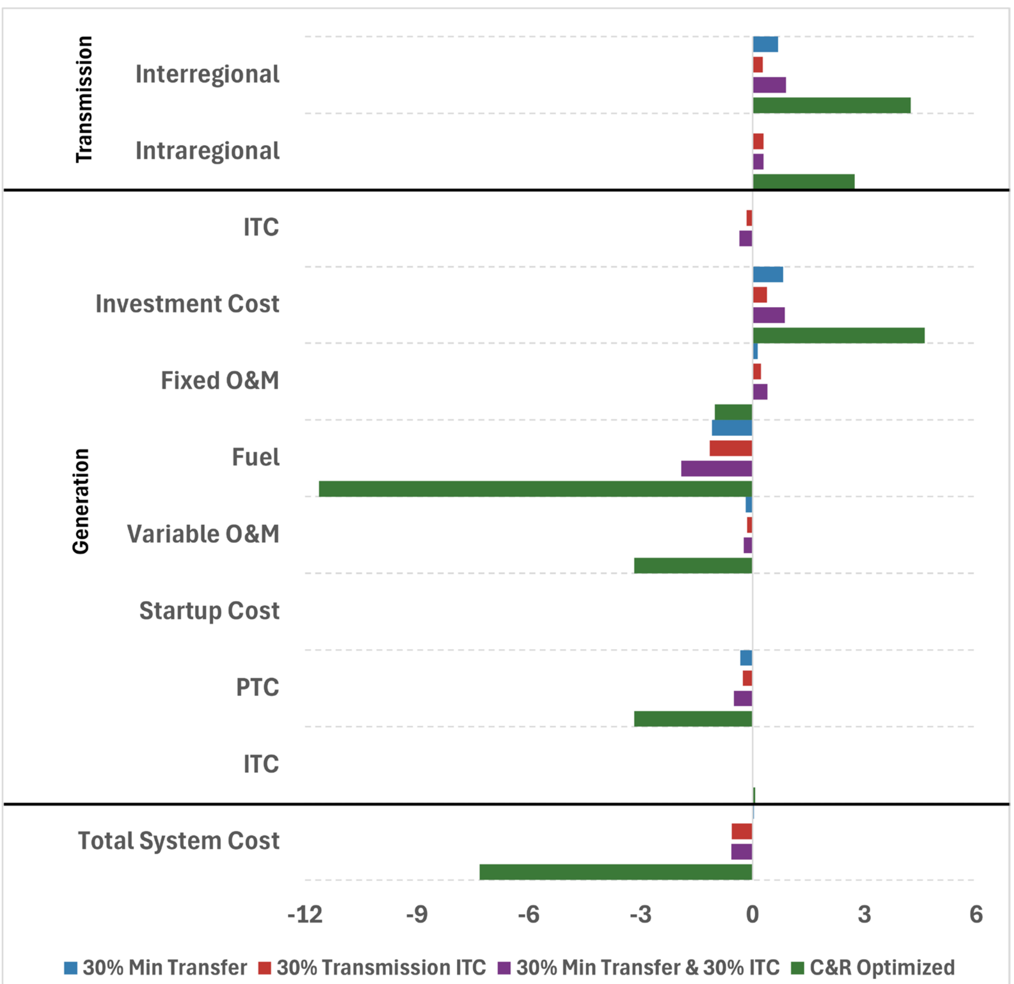
Three of the four policy options evaluated would lower the cost of the electric power system.

In particular, optimizing the grid for cost and reliability would yield substantial savings.

Policy Option	Difference in System Cost Relative to the Status Quo (in Millions of $)
30% Minimum Transfer	+34
30% Transmission ITC	-562
30% Minimum Transfer & 30% Transmission ITC	-566
Cost & Reliability Optimized	-7,319

Figure 7: How Each of the Four Policy Options Would Affect the Costs of Components of the Electric Power System

As the chart below shows, optimizing the grid for cost and reliability could see up to $7.3B in total system cost reductions. Even with large investments in new generation (~$5B) and transmission (~$7B), the vast majority of the cost reductions comes from avoided fuel costs and reduced maintenance (~$15B).



Greenhouse Gas Emissions Reductions

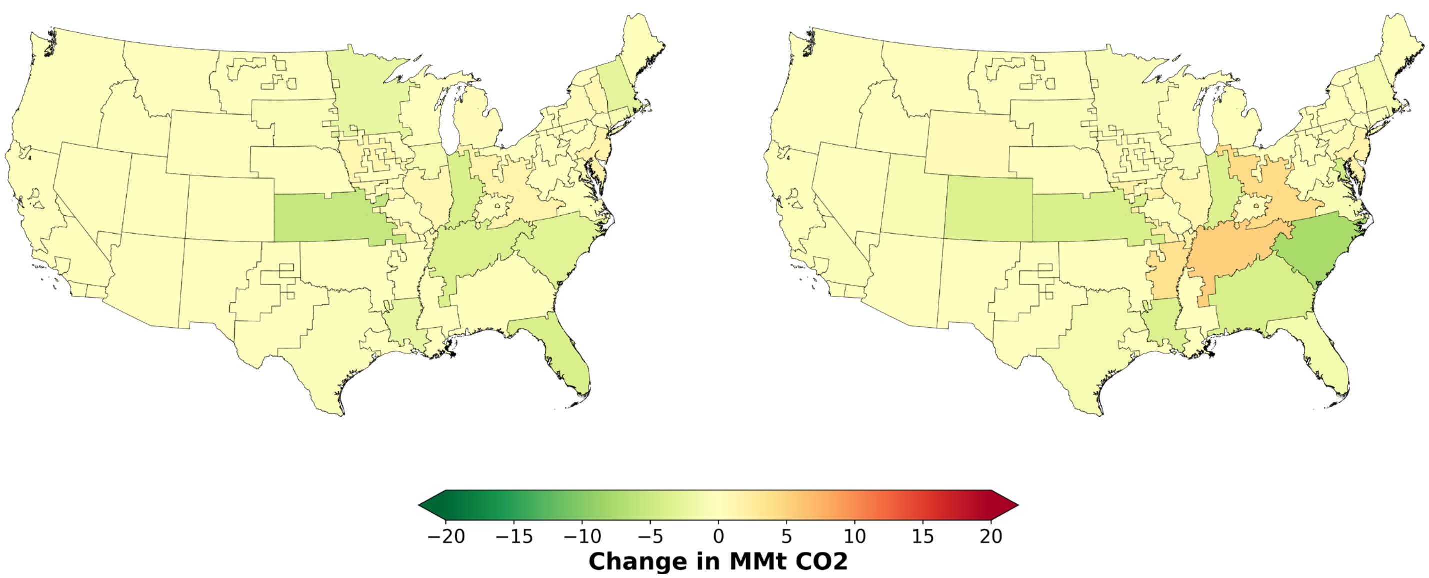
Across all four policy options, we see that increased transmission leads to growth in lower-cost, non-emitting power generation and therefore improves air quality by reducing localized pollution and greenhouse gas (GHG) emissions from traditional coal-fired or natural gas power plants.

As can be seen in the left-hand map in Figure 8, a 30% minimum transfer capability requirement would reduce GHG emissions in most parts of the Southeast, Central, Midwest, Northeast, and Florida regions. Emissions would increase in other parts of the Midwest, as well as in the Mid-Atlantic and New York regions. Nationwide greenhouse gas emissions would be reduced by 3%.

With a 30% transmission investment tax credit, the same regions would experience a net reduction in emissions, but there would be greater intraregional variation, as can be seen in the right-hand map in Figure 8 in the areas around Tennessee, the Carolinas, Georgia, and Alabama. Some additional emissions reduction would occur in the Southwest region. The Mid-Atlantic and New York regions would still exhibit net increases in emissions, but to a lesser extent. The overall reduction in greenhouse gas emissions would be 2.4%.

Figure 8: How a 30% Uniform Minimum Transfer Capability Requirement or a 30% Transmission Investment Tax Credit Would Affect Greenhouse Gas Emissions

Nationwide, greenhouse gas emissions, measured in million metric tons (Mmt) of carbon dioxide equivalent, would be reduced 3% with the minimum transfer capability requirement (shown in the map on the left below) and 2.4% with the investment tax credit (shown in the map on the right.)

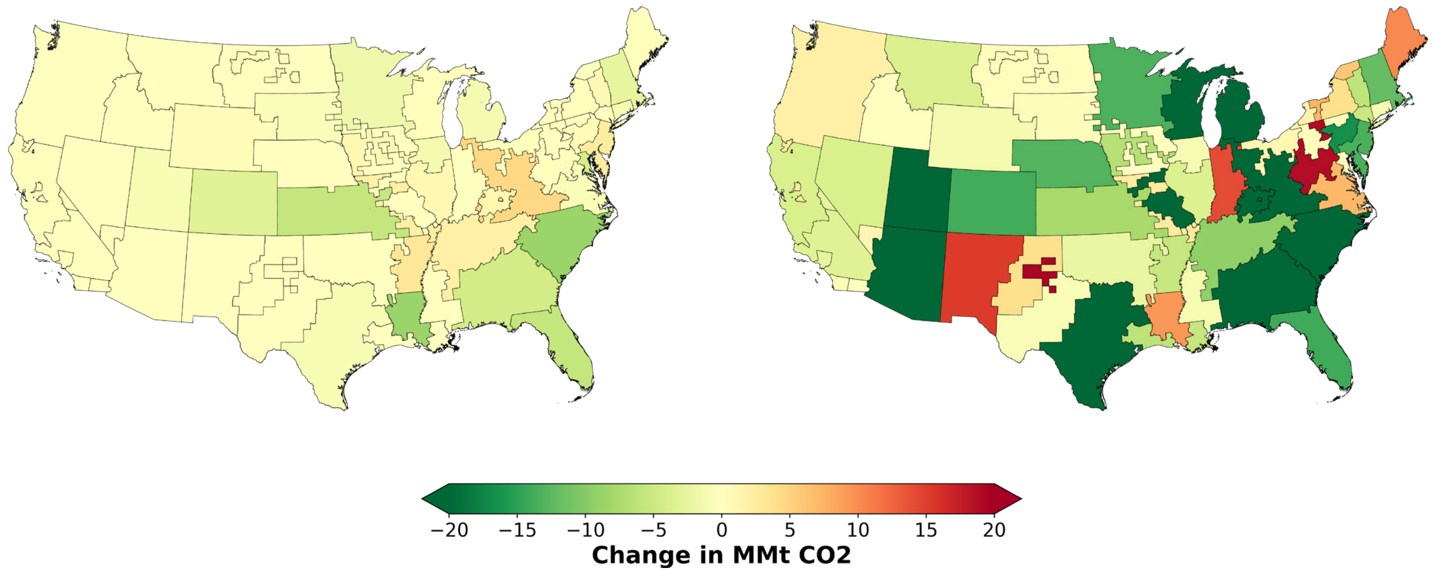


When the 30% minimum transfer capability requirement is combined with the 30% transmission investment tax credit, the nationwide reduction in emissions increases to 3.9%, but there are substantial interregional differences, as shown in the left-hand map in Figure 9. The southeastern US and parts of the Central region see the greatest emissions reductions as a result of this policy option.

Implementing unique, region-specific minimum transfer capability requirements that optimize for cost and reliability (C&R) would result in a 48% reduction in greenhouse gas emissions overall. But, as shown in the right-hand map in Figure 9, greater variation occurs within many regions, like the Southwest, Midwest, Mid-Atlantic, Northwest, and Northeast regions. Only the New York region would exhibit a net increase in emissions.

Figure 9: How Region-Specific Requirements or a Combination of a Uniform Minimum Transfer Capability and an Investment Tax Credit Would Affect Greenhouse Gas Emissions

Nationwide, greenhouse gas emissions would be cut by 3.9% if the 30% minimum transfer capability requirement and investment tax credit were combined (shown in the left-hand map below), and would drop 48% with region-specific requirements optimized for cost and reliability (shown in the right-hand map).



Conclusion

A more reliable, lower-cost, and cleaner electric power system can be achieved in the US by increasing interregional transmission. Policymakers have a variety of policy options for achieving and supporting the buildout of transmission, ranging from simple mandates to subsidies to coordinated planning. Our analysis enumerates the relative benefits of four representative policy options on overall transmission buildout, improved grid reliability in the face of extreme weather events, lower system costs, and lower air pollution and greenhouse gas emissions. As policymakers and stakeholders evaluate transmission policy options, the tools and resources developed by researchers at MIT are available to perform additional analysis.

For more information, contact Drew Story (ClimatePolicyCenter@mit.edu) at the MIT Climate Policy Center.

Note: The views expressed in this policy analysis are the views of the authors and should not be construed as the views of the Massachusetts Institute of Technology.

Appendix

Tables A1-A11: Projected Regional Responses to the Four Policy Options

Each region is projected to respond differently to the four policy options presented, based on its natural resources, geography, population, and the characteristics of its neighboring regions. These differences are highlighted in the tables on the following pages. Some regions, like the Midwest, are most likely to invest heavily in interregional and intraregional transmission and retire most of their fossil fuel generation. This lowers their net system cost, primarily by reducing fuel inputs. Other regions, like the Central region, are most likely to invest heavily in both transmission and clean generation, retiring nearly all of their coal generation. They become power exporters and experience an increase in system cost that yields additional revenue. The tables show the difference in system component costs (in $ million) under each policy option in a given region.

Table A1: The California Region's Projected Responses to the Four Policy Options

California		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	35	17	35	182
	Intraregional	0	0	0	0
	Transmission ITC	0	-5	-10	0
Generation	Investment Cost	1	-34	-3	149
	Fixed O&M	-5	-23	-12	-225
	Fuel	-3	-81	-60	-596
	Variable O&M	0	-9	-7	-71
	Startup Cost	0	-1	-1	-3
	PTC	-1	14	1	-49
	ITC	0	0	0	0
	CCS Incentive	0	0	0	0
Storage	Investment Cost	0	0	0	0
	Fixed O&M	0	0	0	0
	Variable O&M	0	0	0	0
	ITC	0	0	0	0
	System Cost	28	-122	-56	-612
	Revenue	7	-124	-63	-919
	Revenue - Cost	-22	-2	-7	-307

Table A2: The Central Region's Projected Responses to the Four Policy Options

Central		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	53	33	68	1570
	Intraregional	0	0	1	387
	Transmission ITC	0	-9	-19	0
Generation	Investment Cost	405	248	715	10541
	Fixed O&M	47	23	167	3853
	Fuel	-107	-76	-107	-299
	Variable O&M	-45	-31	-43	-143
	Startup Cost	1	1	1	-1
	PTC	-184	-121	-306	-4424
	ITC	-2	0	-2	7
	CCS Incentive	0	0	0	0
Storage	Investment Cost	15	2	5	-80
	Fixed O&M	5	1	1	-25
	Variable O&M	0	0	0	0
	ITC	-2	0	-1	13
	System Cost	185	70	479	11397
	Revenue	274	143	526	8889
	Revenue - Cost	89	73	47	-2508

Table A3: The Florida Region's Projected Responses to the Four Policy Options

Florida		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	56	0	56	59
	Intraregional	0	0	0	0
	Transmission ITC	0	0	-17	0
Generation	Investment Cost	272	61	266	123
	Fixed O&M	146	16	144	1
	Fuel	-310	-98	-441	-1117
	Variable O&M	-36	-11	-51	-132
	Startup Cost	-3	3	6	70
	PTC	-55	-16	-54	-45
	ITC	-5	-2	-5	-4
	CCS Incentive	0	0	0	0
Storage	Investment Cost	53	16	53	39
	Fixed O&M	16	5	16	12
	Variable O&M	0	0	0	0
	ITC	-9	-3	-9	-6
	System Cost	125	-28	-34	-1001
	Revenue	-12	-62	-229	-1328
	Revenue - Cost	-137	-34	-195	-327

Table A4: The Mid-Atlantic Region's Projected Responses to the Four Policy Option

Mid-Atlantic		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	243	23	267	473
	Intraregional	5	137	118	242
	Transmission ITC	0	-48	-115	0
Generation	Investment Cost	-67	-71	-774	-1766
	Fixed O&M	-20	-2	-203	-1516
	Fuel	42	-209	-110	-2130
	Variable O&M	8	9	19	-754
	Startup Cost	0	0	0	9
	PTC	28	-43	166	451
	ITC	0	0	0	-8
	CCS Incentive	0	0	0	0
Storage	Investment Cost	-1	2	-10	64
	Fixed O&M	0	1	-3	20
	Variable O&M	0	0	0	0
	ITC	0	0	2	-10
	System Cost	238	-202	-643	-4925
	Revenue	-129	-189	-784	-4887
	Revenue - Cost	-367	14	-140	38

Table A5: The Midwest Region's Projected Responses to the Four Policy Options

Midwest		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	68	56	136	693
	Intraregional	0	75	87	647
	Transmission ITC	0	-39	-67	0
Generation	Investment Cost	174	25	559	-607
	Fixed O&M	-7	72	193	-1309
	Fuel	-140	-116	-180	-2122
	Variable O&M	-43	-23	-44	-793
	Startup Cost	2	0	1	8
	PTC	-68	-18	-203	-71
	ITC	2	-2	3	11
	CCS Incentive	0	0	0	0
Storage	Investment Cost	-27	25	-39	-117
	Fixed O&M	-8	8	-12	-36
	Variable O&M	0	0	0	-1
	ITC	4	-4	6	19
	System Cost	-43	59	441	-3678
	Revenue	-278	-138	-24	-4151
	Revenue - Cost	-235	-197	-465	-473

Table A6: The New York Region's Projected Responses to the Four Policy Options

New York		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	33	2	40	24
	Intraregional	0	0	0	0
	Transmission ITC	0	-1	-12	0
Generation	Investment Cost	100	55	57	118
	Fixed O&M	2	1	1	35
	Fuel	73	41	81	42
	Variable O&M	13	6	14	8
	Startup Cost	-1	-1	-2	2
	PTC	-30	-15	-16	-34
	ITC	0	0	0	0
	CCS Incentive	0	0	0	0
Storage	Investment Cost	0	0	0	0
	Fixed O&M	0	0	0	0
	Variable O&M	0	0	0	0
	ITC	0	0	0	0
	System Cost	190	88	164	195
	Revenue	225	116	253	218
	Revenue - Cost	34	28	89	23

Table A7: The Northeast Region's Projected Responses to the Four Policy Options

Northeast		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	68	14	68	61
	Intraregional	0	0	0	0
	Transmission ITC	0	-4	-20	0
Generation	Investment Cost	-5	0	0	0
	Fixed O&M	18	17	18	19
	Fuel	-305	-118	-273	-188
	Variable O&M	-39	-15	-34	-24
	Startup Cost	-1	0	-1	-1
	PTC	1	0	0	0
	ITC	0	0	0	0
	CCS Incentive	0	0	0	0
Storage	Investment Cost	0	0	0	0
	Fixed O&M	0	0	0	0
	Variable O&M	0	0	0	0
	ITC	0	0	0	0
	System Cost	-262	-106	-242	-133
	Revenue	-372	-130	-320	-244
	Revenue - Cost	-110	-24	-78	-111

Table A8: The Northwest Region's Projected Responses to the Four Policy Options

Northwest		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	9	15	21	132
	Intraregional	0	36	35	124
	Transmission ITC	0	-15	-17	0
Generation	Investment Cost	32	213	186	-639
	Fixed O&M	16	119	110	-419
	Fuel	-4	-20	-16	-315
	Variable O&M	-1	-5	-3	-125
	Startup Cost	0	0	0	0
	PTC	-16	-101	-94	198
	ITC	0	0	0	0
	CCS Incentive	0	0	0	0
Storage	Investment Cost	0	0	0	0
	Fixed O&M	0	0	0	0
	Variable O&M	0	0	0	0
	ITC	0	0	0	0
	System Cost	36	243	222	-1044
	Revenue	4	110	91	-1635
	Revenue - Cost	-32	-133	-131	-590

Table A9: The Southeast Region's Projected Responses to the Four Policy Options

Southeast		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	96	67	162	656
	Intraregional	1	26	35	302
	Transmission ITC	0	-28	-59	0
Generation	Investment Cost	-18	146	180	-2436
	Fixed O&M	-47	33	9	-1129
	Fuel	-288	-395	-716	-3616
	Variable O&M	-38	-31	-57	-690
	Startup Cost	5	-5	-6	-46
	PTC	-27	-67	-109	596
	ITC	2	1	0	21
	CCS Incentive	0	0	0	0
Storage	Investment Cost	-15	-10	2	-206
	Fixed O&M	-5	-3	0	-62
	Variable O&M	0	0	0	-1
	ITC	2	2	0	33
	System Cost	-331	-264	-559	-6578
	Revenue	-484	-379	-849	-8241
	Revenue - Cost	-153	-115	-290	-1663

Table A10: The Southwest Region's Projected Responses to the Four Policy Options

Southwest		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	11	39	39	233
	Intraregional	0	0	0	234
	Transmission ITC	0	-11	-11	0
Generation	Investment Cost	-107	-98	-135	642
	Fixed O&M	-37	-67	-75	-249
	Fuel	1	-49	-53	-579
	Variable O&M	1	-28	-26	-273
	Startup Cost	-1	-1	-1	-2
	PTC	40	36	51	-278
	ITC	0	0	0	0
	CCS Incentive	0	0	0	0
Storage	Investment Cost	0	0	0	0
	Fixed O&M	0	0	0	0
	Variable O&M	0	0	0	0
	ITC	0	0	0	0
	System Cost	-92	-180	-211	-271
	Revenue	-63	-194	-206	-1029
	Revenue - Cost	29	-14	5	-758

Table A11: The Texas Region's Projected Responses to the Four Policy Options

Texas		30% Min Transfer	30% Transmission ITC	30% Min Transfer and 30% Transmission ITC	C&R Optimized
Transmission	Interregional	5	0	2	149
	Intraregional	0	17	16	806
	Transmission ITC	0	-5	-5	0
Generation	Investment Cost	12	-186	-194	-1233
	Fixed O&M	19	29	37	-20
	Fuel	-49	-31	-39	-707
	Variable O&M	-5	-9	-8	-176
	Startup Cost	3	10	9	-23
	PTC	-14	64	65	492
	ITC	1	1	0	-4
	CCS Incentive	0	0	0	0
Storage	Investment Cost	-10	-8	-8	18
	Fixed O&M	-3	-3	-3	32
	Variable O&M	0	0	0	1
	ITC	2	1	1	-3
	System Cost	-40	-120	-126	-668
	Revenue	-35	-115	-124	-3185
	Revenue - Cost	5	5	2	-2516

Climate Policy Center

Tables B1-B4: How the Four Policy Options Would Affect System Component Costs in Each Region

The following four tables show the differences in system component costs, in millions, for each region under each of the policy options.

Table B1: Differences in System Component Costs, by Region, Resulting from a Uniform 30% Minimum Transfer Capability Requirement

		California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	
Transmission	Interregional Transmission	35	53	56	243	68	33	68	9	96	11	5	676
	Intraregional Transmission	0	0	0	5	0	0	0	0	1	0	0	6
	Transmission ITC	0	0	0	0	0	0	0	0	0	0	0	0
Generation	Investment Cost	1	405	272	-67	174	100	-5	32	-18	-107	12	800
	Fixed O&M	-5	47	146	-20	-7	2	18	16	-47	-37	19	131
	Fuel	-3	-107	-310	42	-140	73	-305	-4	-288	1	-49	-1089
	Variable O&M	0	-45	-36	8	-43	13	-39	-1	-38	1	-5	-184
	Startup Cost	0	1	-3	0	2	-1	-1	0	5	-1	3	4
	PTC	-1	-184	-55	28	-68	-30	1	-16	-27	40	-14	-326
	ITC	0	-2	-5	0	2	0	0	0	2	0	1	-3
	CCS Incentive	0	0	0	0	0	0	0	0	0	0	0	0
Storage	Investment Cost	0	15	53	-1	-27	0	0	0	-15	0	-10	16
	Fixed O&M	0	5	16	0	-8	0	0	0	-5	0	-3	5
	Variable O&M	0	0	0	0	0	0	0	0	0	0	0	0
	ITC	0	-2	-9	0	4	0	0	0	2	0	2	-3
	System Cost	28	185	125	238	-43	190	-262	36	-331	-92	-40	34
	Revenue Difference	7	274	-12	-129	-278	225	-372	4	-484	-63	-35	-864
	Revenue - Cost Difference	-22	89	-137	-367	-235	34	-110	-32	-153	29	5	-898

Table B2: Differences in System Component Costs, by Region, Resulting from a 30% Transmission Investment Tax Credit

		California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	
Transmission	Interregional Transmission	17	33	0	23	56	2	14	15	67	39	0	267
	Intraregional Transmission	0	0	0	137	75	0	0	36	26	0	17	291
	Transmission ITC	-5	-9	0	-48	-39	-1	-4	-15	-28	-11	-5	-165
Generation	Investment Cost	-34	248	61	-71	25	55	0	213	146	-98	-186	359
	Fixed O&M	-23	23	16	-2	72	1	17	119	33	-67	29	218
	Fuel	-81	-76	-98	-209	-116	41	-118	-20	-395	-49	-31	-1151
	Variable O&M	-9	-31	-11	9	-23	6	-15	-5	-31	-28	-9	-146
	Startup Cost	-1	1	3	0	0	-1	0	0	-5	-1	10	6
	PTC	14	-121	-16	-43	-18	-15	0	-101	-67	36	64	-267
	ITC	0	0	-2	0	-2	0	0	0	1	0	1	-3
	CCS Incentive	0	0	0	0	0	0	0	0	0	0	0	0
Storage	Investment Cost	0	2	16	2	25	0	0	0	-10	0	-8	27
	Fixed O&M	0	1	5	1	8	0	0	0	-3	0	-3	8
	Variable O&M	0	0	0	0	0	0	0	0	0	0	0	0
	ITC	0	0	-3	0	-4	0	0	0	2	0	1	-4
	System Cost	-122	70	-28	-202	59	88	-106	243	-264	-180	-120	-562
	Revenue Difference	-124	143	-62	-189	-138	116	-130	110	-379	-194	-115	-962
	Revenue - Cost Difference	-2	73	-34	14	-197	28	-24	-133	-115	-14	5	-400

Table B3: Differences in System Component Costs, by Region, Resulting from Combining a 30% Minimum Transfer Capability Requirement with a 30% Transmission Investment Tax Credit

		California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	
Transmission	Interregional Transmission	35	68	56	267	136	40	68	21	162	39	2	894
	Intraregional Transmission	0	1	0	118	87	0	0	35	35	0	16	290
	Transmission ITC	-10	-19	-17	-115	-67	-12	-20	-17	-59	-11	-5	-352
Generation	Investment Cost	-3	715	266	-774	559	57	0	186	180	-135	-194	857
	Fixed O&M	-12	167	144	-203	193	1	18	110	9	-75	37	392
	Fuel	-60	-107	-441	-110	-180	81	-273	-16	-716	-53	-39	-1914
	Variable O&M	-7	-43	-51	19	-44	14	-34	-3	-57	-26	-8	-239
	Startup Cost	-1	1	6	0	1	-2	-1	0	-6	-1	9	6
	PTC	1	-306	-54	166	-203	-16	0	-94	-109	51	65	-499
	ITC	0	-2	-5	0	3	0	0	0	0	0	0	-4
	CCS Incentive	0	0	0	0	0	0	0	0	0	0	0	0
Storage	Investment Cost	0	5	53	-10	-39	0	0	0	2	0	-8	2
	Fixed O&M	0	1	16	-3	-12	0	0	0	0	0	-3	1
	Variable O&M	0	0	0	0	0	0	0	0	0	0	0	0
	ITC	0	-1	-9	2	6	0	0	0	0	0	1	0
	System Cost	-56	479	-34	-643	441	164	-242	222	-559	-211	-126	-566
	Revenue Difference	-63	526	-229	-784	-24	253	-320	91	-849	-206	-124	-1729
	Revenue - Cost Difference	-7	47	-195	-140	-465	89	-78	-131	-290	5	2	-1163

Table B4: Differences in System Component Costs, by Region, Resulting from Unique, Region-Specific Minimum Transfer Capability Requirements that Optimize for System-Wide Cost and Regional Reliability

		California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	
Transmission	Interregional Transmission	182	1570	59	473	693	24	61	132	656	233	149	4231
	Intraregional Transmission	0	387	0	242	647	0	0	124	302	234	806	2741
	Transmission ITC	0	0	0	0	0	0	0	0	0	0	0	0
Generation	Investment Cost	149	10541	123	-1766	-607	118	0	-639	-2436	642	-1233	4891
	Fixed O&M	-225	3853	1	-1516	-1309	35	19	-419	-1129	-249	-20	-959
	Fuel	-596	-299	-1117	-2130	-2122	42	-188	-315	-3616	-579	-707	-11625
	Variable O&M	-71	-143	-132	-754	-793	8	-24	-125	-690	-273	-176	-3172
	Startup Cost	-3	-1	70	9	8	2	-1	0	-46	-2	-23	13
	PTC	-49	-4424	-45	451	-71	-34	0	198	596	-278	492	-3166
	ITC	0	7	-4	-8	11	0	0	0	21	0	-4	22
	CCS Incentive	0	0	0	0	0	0	0	0	0	0	0	0
Storage	Investment Cost	0	-80	39	64	-117	0	0	0	-206	0	18	-283
	Fixed O&M	0	-25	12	20	-36	0	0	0	-62	0	32	-59
	Variable O&M	0	0	0	0	-1	0	0	0	-1	0	1	0
	ITC	0	13	-6	-10	19	0	0	0	33	0	-3	46
	System Cost	-612	11397	-1001	-4925	-3678	195	-133	-1044	-6578	-271	-668	-7319
	Revenue Difference	-919	8889	-1328	-4887	-4151	218	-244	-1635	-8241	-1029	-3185	-16513
	Revenue - Cost Difference	-307	-2508	-327	38	-473	23	-111	-590	-1663	-758	-2516	-9193