NERC's Recommended Grid Expansion Would Save Consumers Billions

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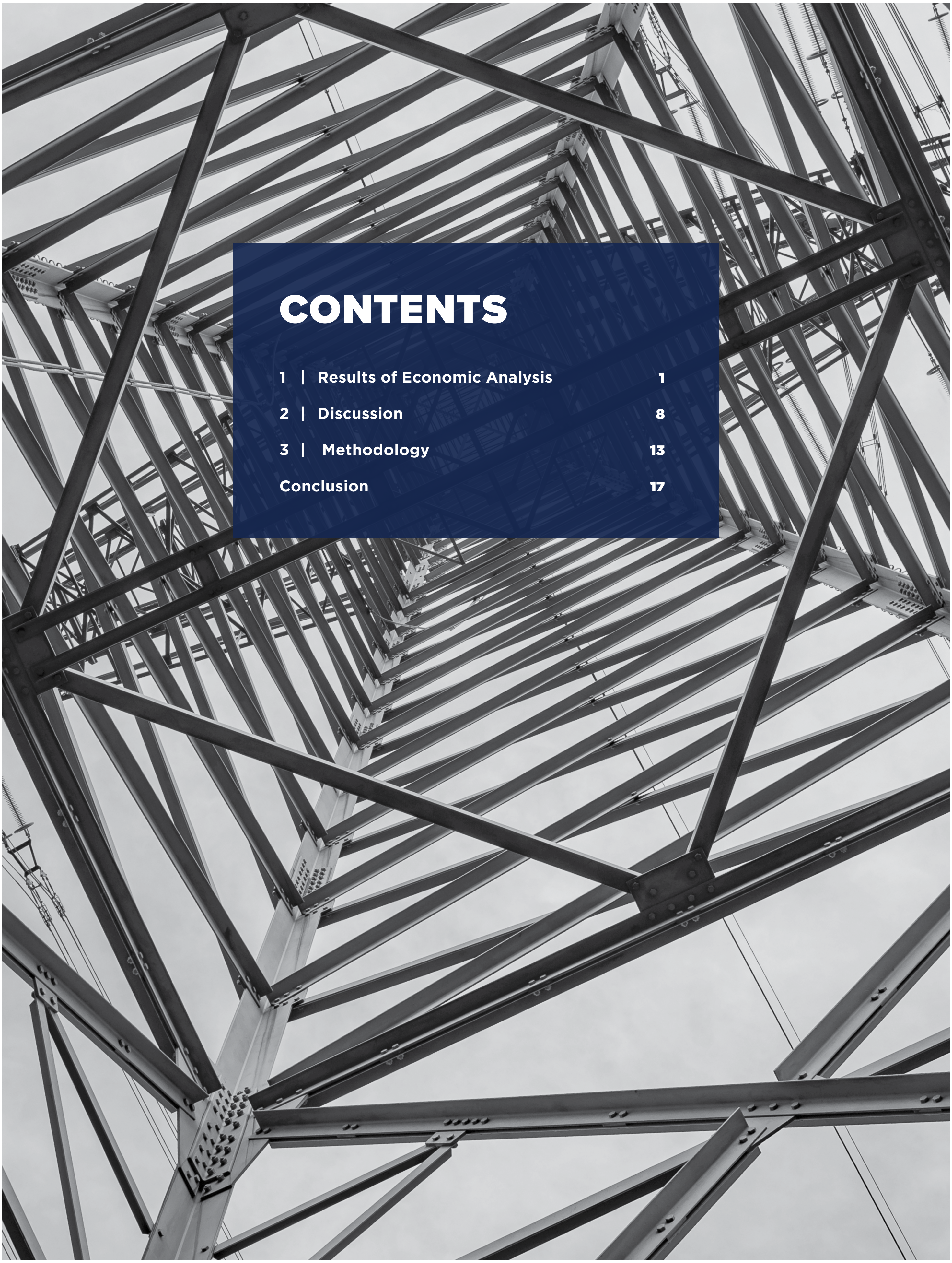
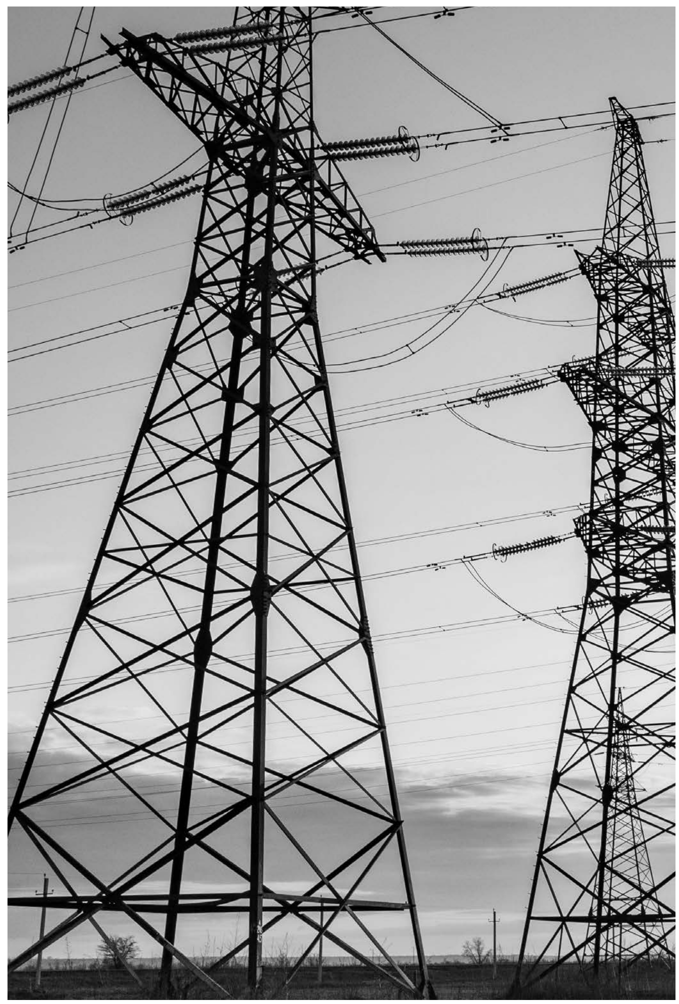


CONTENTS

1 | RESULTS OF ECONOMIC ANALYSIS

In November 2024, the North American Electric Reliability Corporation (NERC) filed the Interregional Transfer Capability Study (ITCS) with the Federal Energy Regulatory Commission (FERC). As directed by Congress, the study focused exclusively on interregional transmission additions to address reliability concerns, without considering the economic benefits of transmission expansion. NERC's report acknowledges, however, that such benefits could be substantial and that the report is best used as a starting point for interregional transmission planning that maintains "an open perspective toward potential solutions…to create a resilient approach that aligns with regional conditions and economic viability."[1]



Building on NERC's work, this paper quantifies several of the economic benefits provided by the interregional transmission expansion recommended in the ITCS. Our analysis shows that the benefits of the transmission investment far outweigh the costs, even without fully accounting for all of the benefits of transmission. **Each $1 invested in the transmission expansion recommended in NERC's ITCS would yield benefits of $4.30 to $5.80, with a payback period of less than three years.** More specifically, while NERC's proposed transmission investments would cost around $1.8 billion per year, **they would deliver annual benefits to ratepayers ranging from $7.8 billion to $10.6 billion.** These findings are summarized in the table and figures below.

1 NERC, *Interregional Transfer Capability Study (ITCS),* https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/ITCS_Filing_Fall2024_signed.pdf, at xix, 11.

TABLE 1 | Benefits and cost of ITCS interregional transmission expansion

Annualized benefit/cost	Low benefit estimate	High benefit estimate
Preventing loss of load	$1.1 billion	$3.9 billion
More productive wind	$1.1 billion	
More productive solar	$0.251 billion	
Production cost savings	$5.3 billion	
Total annual benefits	**$7.8 billion**	**$10.6 billion**
Annual transmission cost	$1.8 billion	
Net annual benefits	**$6.0 billion**	**$8.8 billion**
Benefit:Cost ratio	**4.3**	**5.8**
Benefits over 50 years	$389 billion	$528 billion
Net benefits over 50 years	$366 billion	$506 billion
Payback period for transmission investment	2.9 years	2.1 years

As the following figures show, about half to two-thirds of the calculated benefits accrue from production cost savings from accessing lower-cost generation, while a large share of the remainder are from preventing customer loss of load. The remaining 15% of the calculated benefits result from accessing more productive wind and solar resources.

FIGURE 1 | Low range estimate of annual benefits and cost of ITCS transmission

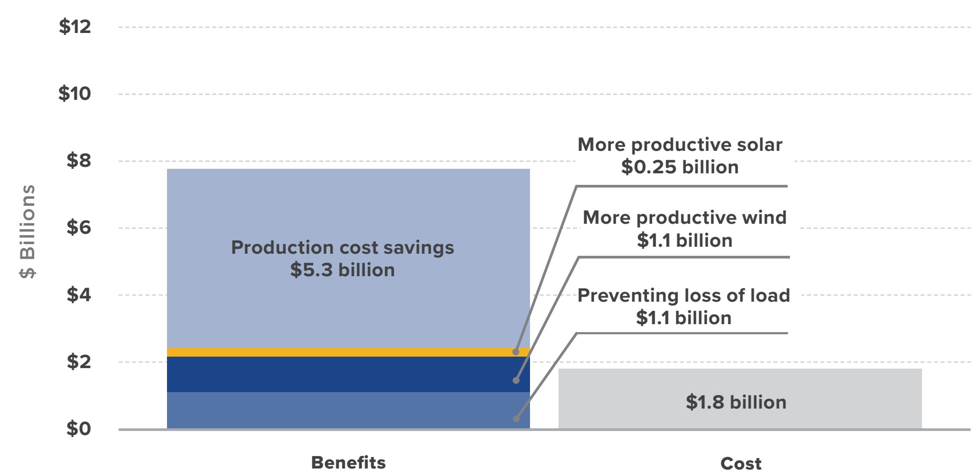
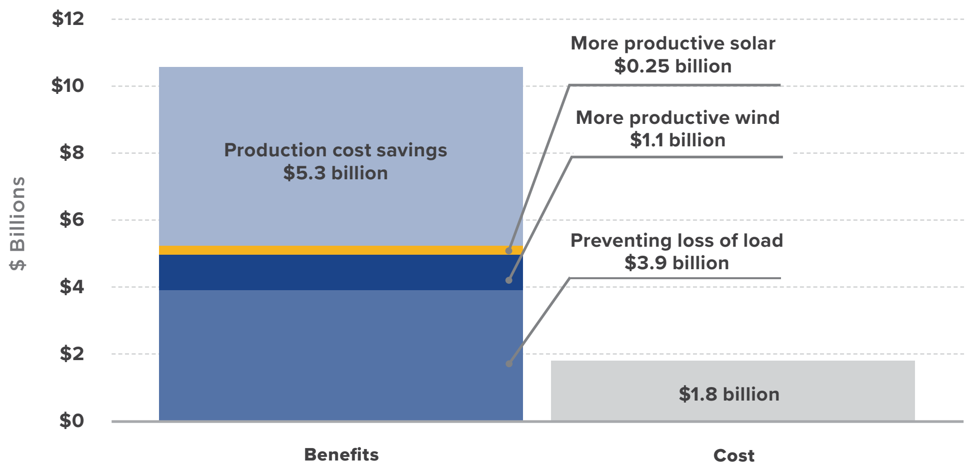


FIGURE 2 | High range estimate of annual benefits and cost of ITCS transmission



This is a conservative estimate of the total benefits provided by interregional transmission. FERC's Order 1920 identifies seven minimum benefits of transmission that transmission providers must evaluate:

1. *Avoided or deferred reliability transmission facilities and aging infrastructure replacement;*
2. *A benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;*
3. *Production cost savings;*
4. *Reduced transmission energy losses;*
5. *Reduced congestion due to transmission outages;*
6. *Mitigation of extreme weather events and unexpected system conditions; and*
7. *Capacity cost benefits from reduced peak energy losses.*[2]

Our analysis quantifies item 3 and part of item 2, and benefits 5 and 6 are at least partially captured in the historical data that underlies our estimate of production cost savings. We do not attempt to quantify the other benefits that FERC requires transmission providers to evaluate, even though other studies have shown them to be significant. For example, the Midcontinent Independent System Operator (MISO) has quantified benefit 1 and found that its proactively planned transmission expansion provides net present value benefits of $1.3-1.9 billion by deferring the need for reliability upgrades and aging infrastructure replacement.[3] Additionally, our analysis also accounts for generator cost savings from accessing more productive

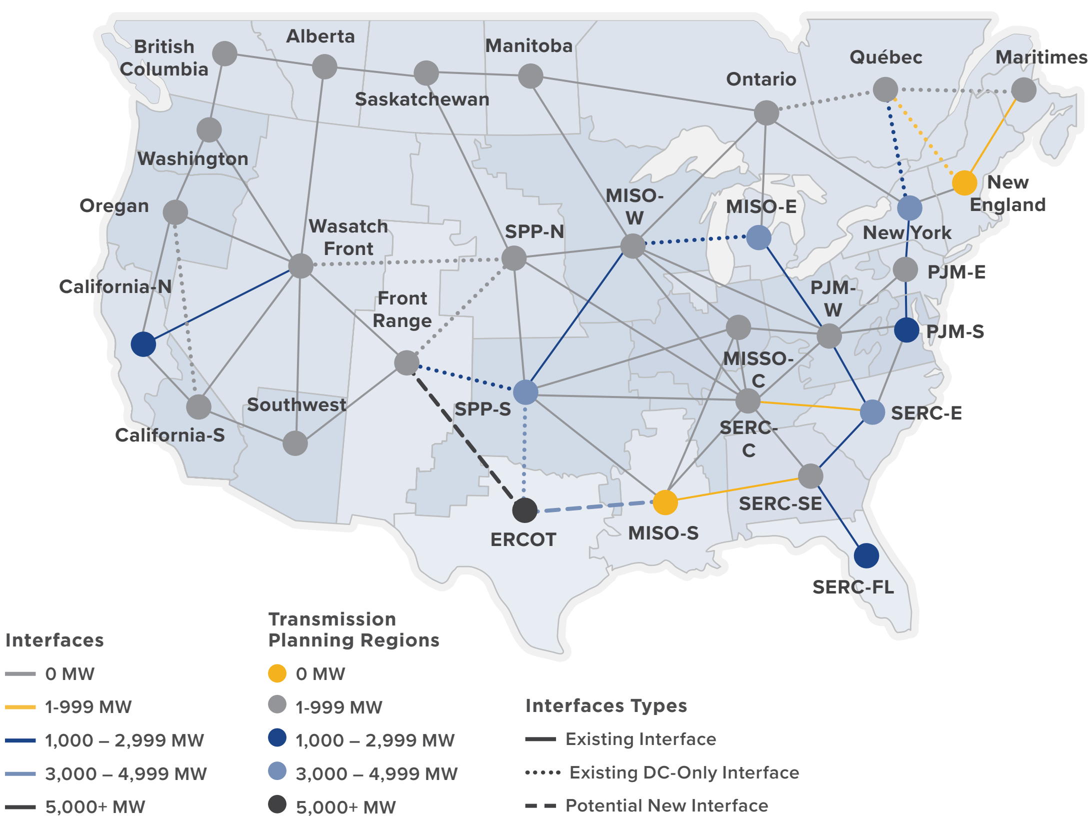
2 FERC, *Order 1920A*, https://www.ferc.gov/media/e-1-rm-21-17-001, at Paragraph 369, citing *Order 1920 at Paragraph 720*

3 MISO, *LRTP Tranche 1 Portfolio Detailed Business Case*, https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf at 27

resources, a benefit that FERC did not include in its mandatory list but acknowledges is a known benefit that regions like MISO[4] and the Southwest Power Pool (SPP)[5] have accounted for in assessing the net benefits of their transmission expansion.

The following map summarizes the interregional transmission additions NERC recommended in the ITCS.

FIGURE 3 | NERC ITCS map of prudent additions[6]



Our estimate of the cost and benefits of each expanded interregional tie are shown below. Each regional tie expansion delivers benefits that exceed its costs, with most ties generating returns that far outweigh their investment cost.

4 MISO, *MTEP17 MVP Triennial Review,* https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf at 32

5 SPP, *The Value of Transmission,* https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf at 19; SPP, *The Value of Transmission: 2021 Edition,* https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf at 16

6 ITCS, at xvi

TABLE 2 | Cost and benefits of each interregional tie expansion

First region	Second region	MW	Annualized cost ($M)	Annual benefit, low($M)	Annual benefit, high ($M)	B:C ratio, low	B:C ratio, high
Wasatch Front	Cal N	1100	$54	$149	$181	2.75	3.33
Front Range	ERCOT	5700	$513	$1,803	$2,663	3.51	5.19
MISO S	ERCOT	4300	$368	$1,341	$1,990	3.64	5.40
SPP S	ERCOT	4100	$238	$2,201	$2,820	9.23	11.83
Front Range	SPP S	1200	$109	$308	$355	2.81	3.24
MISO W	SPP S	1700	$36	$288	$355	7.97	9.82
SERC SE	MISO S	300	$1	$12	$15	8.11	10.24
MISO W	MISO E	2000	$86	$396	$580	4.58	6.72
PJM W	MISO E	1000	$12	$218	$311	18.62	26.48
SERC SE	SERC FL	1200	$10	$29	$37	2.90	3.66
PJM W	SERC E	1600	$13	$223	$247	16.57	18.40
SERC C	SERC E	300	$21	$33	$38	1.57	1.79
SERC SE	SERC E	2200	$32	$165	$199	5.22	6.29
PJM E	PJM S	2800	$37	$290	$385	7.92	10.50
PJM E	NYISO	1800	$284	$316	$392	1.11	1.38
	Total	**32,400**	**$1,816**	**$7,772**	**$10,567**	**4.3**	**5.8**

To prevent double counting, this list excludes 800 MW of transmission from ERCOT to SPP South and 300 MW of transmission from ERCOT to MISO South, as those costs and benefits are encompassed in the larger expansion in the other direction between those regions. In addition, the cost and benefits of 1,900 MW of transmission ties between New York and Canada and 700 MW of ties between New England and Canada were not included in our analysis, as the Lawrence Berkeley National Laboratory (LBNL) paper used to estimate production cost savings does not include market price information for Canada that would allow an estimate of production cost savings for those lines.[7] Because it excluded those 2,600 MW of ties with Canada, our analysis accounted for 32,400 MW of the 35,000 MW of prudent additions identified in the ITCS.

7 While LBNL's analysis is based on Locational Marginal Prices (LMPs), this should be a close proxy for production cost savings as marginal prices are typically set based on the marginal production cost of the marginal resource in each geographic location.

Expanding interregional ties benefits both regions

In most if not all cases, the expanded ties provide large net benefits to both regions. For example, the ties between ERCOT and SPP and between ERCOT and MISO South help avoid loss of load in both regions. We have previously documented how transmission ties benefit both connected regions because there is often a significant difference in the timing of their peak needs, as shown in the figure below. For example, during Winter Storm Elliott in December 2022, MISO initially imported power from PJM, but then flows reversed as the severe cold moved eastward into PJM.[8] Moreover, a region that primarily exports during one severe weather event may primarily import during the next event. For example, MISO was primarily importing from PJM during Winter Storm Uri in February 2021, but was primarily exporting to PJM during the January 2018 Bomb Cyclone and the January 2014 Polar Vortex event.[9]

The differences in regions' timing of peak need are summarized in the following figure from a report Grid Strategies submitted to FERC in May 2023.[10] Each row provides a snapshot during an extreme weather event of each region's net load (which we define here as load minus renewable output plus forced outages of conventional generators) as a percentage of that region's maximum need during the 9 years we analyzed.

FIGURE 4 | Each region's hourly net load as a share of the region's peak need over 9 years

	ERCOT	SPP	MISO S	TVA	MISO N	PJM	NYISO	ISO-NE	Carolinas	SOCO	Florida
1/17/2014 7 AM ET	58%	60%	74%	86%	75%	100%	68%	64%	88%	87%	60%
1/17/2018 10 AM ET	60%	67%	100%	81%	61%	70%	61%	63%	56%	85%	61%
1/18/2018 6 AM ET	58%	50%	65%	76%	55%	66%	51%	55%	63%	100%	79%
2/15/2021 10 AM ET	100%	99%	83%	61%	69%	63%	56%	59%	58%	68%	55%
12/23/2022 6 PM ET	68%	87%	88%	99%	86%	85%	60%	56%	88%	91%	65%
12/24/2022 6 AM ET	63%	87%	87%	91%	77%	85%	49%	50%	100%	95%	66%

The benefits from accessing more productive renewable resources can also be bidirectional. For example, expanding ties between Duke and PJM allows Duke to access lower-cost PJM wind,

8 M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott,* https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf

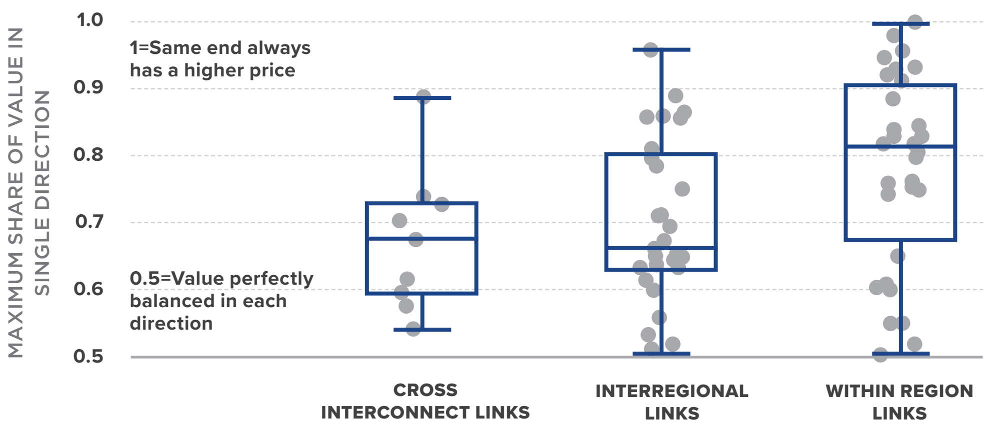
9 M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather,* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

10 M. Goggin *et al., Quantifying a Minimum Interregional Transfer Capability Requirement,* https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4

while PJM is able to access better solar resources in Duke's territory. This benefit is even more pronounced on an hourly basis because wind and solar output are negatively correlated on a daily and seasonal basis and due to geographic diversity in renewable output patterns, but that benefit is accounted for in production cost savings.

In most cases the production cost savings from expanding ties are also fairly evenly split between the two regions. As demonstrated in the following chart from its study, LBNL shows that the benefits of interregional transmission lines are more evenly distributed between both ends of the line compared to transmission lines within a single region. The benefits of ties between the Eastern, Western, and ERCOT Interconnections are even more evenly distributed, as indicated by "cross-interconnect links" appearing towards the bottom of the following chart.

FIGURE 5 | **LBNL chart showing the distribution of benefits for different types of lines**[11]



11 J. Kemp *et al.*, *Electric transmission value and its drivers in United States power markets*, https://www.researchsquare.com/article/rs-3957695/v1, at 4

2 | DISCUSSION

Because the interregional transmission expansion recommended in the ITCS was designed solely to prevent loss of load events, it falls short of the optimal transmission expansion to more comprehensively meet future needs.

The grid expansion recommended in the ITCS understates the need for transmission

The ITCS's recommended interregional transmission capacity additions understate the total need for interregional transmission expansion for three primary reasons.

First, Congress's mandate to NERC was to recommend prudent interregional transmission additions that would demonstrably strengthen reliability,[12] **so NERC did not account for transmission's other benefits when assessing the need for expansion.** The ITCS only accounts for part of one of FERC's seven transmission benefits discussed above: transmission reducing a region's loss of load probability or planning reserve margin by accessing diversity in electricity supply and demand with neighboring regions. The ITCS only attempted to reduce loss of load, and did not attempt to optimally reduce planning reserve margins. In most if not all cases transmission expansion that prevents load loss in one region provides value to the other region by reducing the generator capacity needed to ensure resource adequacy, but neither the NERC study nor our analysis attempted to quantify that benefit. The ITCS accurately caveats that "Economic analysis, cost-benefit evaluation, or financial modeling were not factors in determining prudent recommendations. The focus was strictly on improving energy adequacy."[13]

A study with a more comprehensive scope would have accounted for the multiple benefits of transmission, as well as its cost, to identify an economically optimal transmission expansion. The Department of Energy's (DOE's) recent National Transmission Planning Study had that more comprehensive scope,[14] and as summarized in the figure below it found far larger transmission expansions to be economically optimal. The DOE study also looked beyond neighboring regions to build an optimal national transmission network, overcoming the second major limitation of the ITCS.

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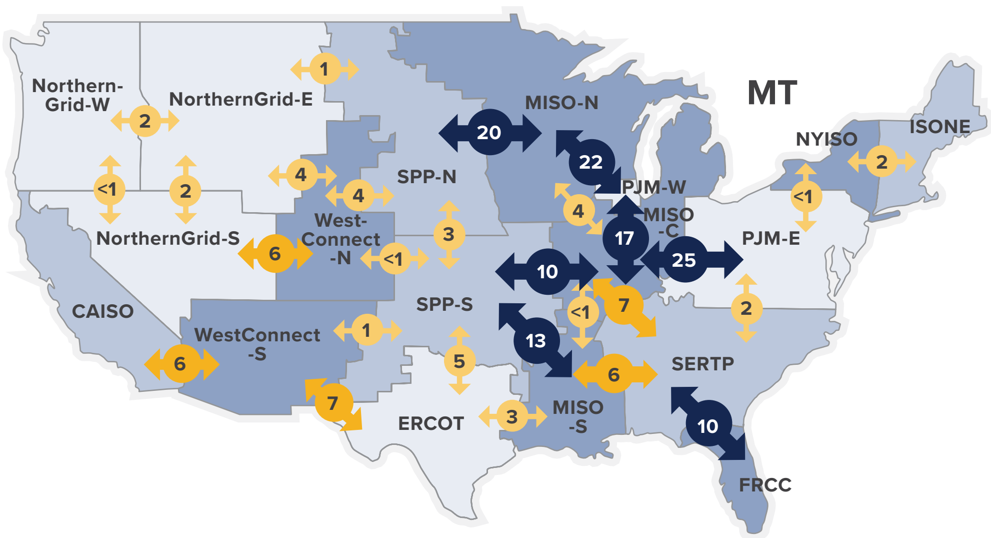
12 *Fiscal Responsibility Act, H.R. 3746 (2023), Section 322*

13 ITCS at viii

14 DOE, *National Transmission Planning Study*, https://www.energy.gov/gdo/national-transmission-planning-study

FIGURE 6 GW increase in transfer capacity among regions in DOE National Transmission Planning Study Multi-Terminal (MT) High Voltage Direct Current optimized solution



Second, the ITCS did not look beyond a region's immediate neighbors when identifying opportunities for transmission expansion. This shortcoming was compounded by the fact that the study divided the country into relatively small regions, so potentially valuable transmission expansion pathways were not evaluated. For example, transmission expansion from Texas to the Southeast or Southwest was not evaluated because the study map did not place those regions directly next to each other, even though other studies have found those paths to be highly valuable.[15]

The ITCS identified regions with expected generation shortfalls, and then expanded transmission to that region's immediate neighbors to access load and resource diversity to help meet that shortfall. However, in nearly all regions this left an unmet need for generation, as shown below. Building transmission beyond immediate neighbors likely could have met that remaining need, which would have resulted in a much larger transmission expansion than NERC's recommendation. If the 13,500 MW of remaining generation need were met by adding 13,500 MW of transmission to the immediate neighbor and an additional 13,500 MW of transmission to that neighbor's neighbor, that would have increased the total recommended transmission additions to around 62,000 MW, 77% larger than NERC's recommendation of 35,000 MW.

15 For example, see Lawrence Berkeley National Laboratory, *Transmission Value in 2023,* https://emp.lbl.gov/news/transmission-value-2023-market-data-shows-value-transmission-remained-high-certain and Energy Systems Integration Group, M*ulti-Value Transmission Planning for a Clean Energy Future,* https://www.esig.energy/wp-content/uploads/2022/06/ESIG-Multi-Value-Transmission-Planning-report-2022.pdf at x

TABLE 3 | Unmet need for transmission expansion in the ITCS

Region	Resource Deficiency (MW)	Prudent Additions (MW)	Unmet need for imports (MW)
ERCOT	18,926	14,100	4,826
MISO E (MI)	5,715	3,000	2,715
NY	3,729	3,700	29
SPP S	4,137	3,700	437
PJM S (Dominion)	4,147	2,800	1,347
California N	3,211	1,100	2,111
SERC E (Carolinas)	5,849	4,100	1,749
SERC FL	1,152	1,200	-48
New England	984	700	284
MISO S	629	600	29
Total	**48,479**	**35,000**	**13,527**

Third, even for the ITCS's narrow scope of identifying transmission expansion needed to keep the lights on, the recommended prudent additions are likely conservative for several reasons.

The ITCS included a sensitivity analysis assuming that regions must maintain 6% extra generating capacity to cover operating reserve needs and other uncertainties, rather than the 3% operating reserve assumption used in the base case results, which identified 35,000 MW of recommended transmission additions, as shown in the table above. In the 6% sensitivity recommended transmission additions increased to around 58,000 MW,[16] with significant increases in all regions except Texas. A 6% operating reserve margin is consistent with the level of contingency reserves often held in the Western U.S.,[17] and may better approximate the level of operating reserves held by other relatively small grid operators, such as those in the Southeast.[18] If the 6% sensitivity were combined with the 77% larger neighbor-of-neighbor transmission expansion discussed in the paragraph above, the study's total recommended transmission expansion could have exceeded 100,000 MW.

16 ITCS at 105-106

17 NERC, *WECC Standard BAL-002-WECC-2a — Contingency Reserve*, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-2a.pdf, at 1

18 E. Hale and E. Zhou, *Absorbing the Sun: Operational Practices and Balancing Reserves in Florida's Municipal Utilities*, https://www.nrel.gov/docs/fy21osti/79385.pdf

Further, the study's recommended need for transmission is based on load growth projections from 2023, and the study acknowledges it did not account for "recent changes to load forecasts, renewable targets, or retirement announcements."[19] Many regions have since dramatically increased their projections for load growth,[20] while supply chain constraints and generator interconnection queue backlogs continue to delay and limit additions of new generating capacity.[21] As a result regional generation shortfalls are likely to be even larger than the ITCS projects, increasing the need for interregional transmission.

Most climate scientists expect climate change to cause extreme weather events that result in regional spikes in electricity demand and generation shortfalls to become more severe and frequent[22] than they were over the 12 historical years evaluated in the NERC study. Finally, if increased reliance on gas generation continues to outpace expansion and weatherization of supporting gas production, storage, and transportation infrastructure, the correlated failures of gas generators that led to regional power outages during events like Winter Storms Uri and Elliott are likely to become even more severe.

The benefit-cost ratio identified in our analysis is higher than those found by MISO and SPP[23] in their evaluations of intra-regional transmission expansion. This is expected, as interregional transmission expansion tends to offer larger benefits due to the greater diversity among regions

19 ITCS at vii

20 For example, see J. Wilson in NERC, *Large Loads Task Force Kickoff Meeting,* https://www.nerc.com/comm/RSTC/LLTF/LLTF_Kickoff_Presentations.pdf at 75

21 Lawrence Berkeley National Laboratory, *Queued Up,* https://emp.lbl.gov/queues

22 FERC, Order 896, https://www.ferc.gov/media/e-1-rm22-10-000

23 MISO, *LRTP Tranche 1 Portfolio Detailed Business Case,* https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf; SPP, *The Value of Transmission: 2021 Edition,* https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf

than within regions in the timing of peak needs. As LBNL's analysis documents, "The market value for the median cross-interconnect and interregional links are $30/MWh and $15/MWh, respectively, compared to $8/MWh for a within-region link."[24] Other analyses that have focused on reducing lost load, which was the sole focus of the ITCS expansion, have also found very high benefit-cost ratios. For example, Duke Energy has found that transmission upgrades within its service territory provide benefit:cost ratios in the range of 4:1 to 34:1 based solely on their value for reducing customer loss of load.[25] Because power outages – especially widespread and prolonged events like those during Winter Storm Uri in Texas – are extremely costly and disruptive to society, the ITCS's addition of this minimum level of transmission needed to maintain reliability will generate significant net benefits.

As discussed in the previous section, in most cases the benefits of interregional transmission are fairly evenly distributed between the connected regions. Moreover, within each region, all ratepayers benefit from lower-cost and more reliable power. Interregional transmission also serves as an insurance policy against the reliability and economic impacts of severe weather and other unexpected events, a benefit that is widely shared. Future severe weather events will not precisely replicate the patterns of past events, and regions that were fortunate enough not to experience an extremely challenging event during the 12 historical weather years included in NERC's analysis are likely to face such an event at some point. This broad but inherently uncertain distribution of benefits suggests that the costs of interregional transmission should be broadly allocated, consistent with FERC principles that costs should be paid by beneficiaries.

24 J. Kemp *et al.*, *Electric transmission value and its drivers in United States power markets,* https://www.researchsquare.com/article/rs-3957695/v1

25 D. Roberts, *Supplemental Direct Testimony of Dewey S. Roberts II on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC,* https://dms.psc.sc.gov/Attachments/Matter/8cdccf8b-fe60-4bef-9214-24bdd66ed689, at 8

3 | METHODOLOGY

Transmission Benefits

Value of lost load

There are a wide range of estimates for the value of lost load, which vary based on study methodology. As a result, we used a low and high estimate for the value of lost load. The low estimate of $10,000/MWh is based on a March 2024 proposal by MISO,[26] while the high estimate of $35,000/MWh is based on The Brattle Group's September 2024 recommendation for ERCOT.[27] MISO and ERCOT make up a large share of the total lost load mitigated by transmission expansion in the ITCS, so it is reasonable to base the value of lost load calculation on cost figures for those regions.

The ITCS only attempted to mitigate loss of load events. As noted above, this is likely a major understatement of the total value of transmission for keeping the lights on and reducing the generator capacity needed for resource adequacy. First, as noted above, the ITCS did not use neighbor-of-neighbor ties, so the transmission expansion was not large enough to mitigate all loss of load. Second, in most if not all cases transmission expansion that prevents load loss in one region provides value to the other region by reducing the generator capacity needed to ensure resource adequacy, but neither the ITCS nor our analysis attempted to quantify the value of reducing planning reserve margins. FERC's list of benefits discussed earlier in this report notes that the second benefit on its list "can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin." The value of reducing planning reserve margins was not accounted for in our analysis because probabilistic analysis combining net load patterns for both regions over many decades is typically required to determine the extent to which a transmission tie enables a reduction in planning reserve margin. Third and relatedly, the economically optimal transmission expansion, and thus its benefits, would likely be far larger if the ITCS attempted to optimally reduce generator capacity costs instead of simply building enough transmission to keep the lights on.

Production cost savings

Analysis conducted by LBNL was used to estimate the production cost savings provided by

26 MISO, *Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve*, https://cdn.misoenergy.org/20240418%20MSC%20Item%2004d%20Scarcity%20Pricing%20White%20Paper%20VOLL%20and%20ORDC632355.pdf

27 Brattle Group, *Value of Lost Load Study for the ERCOT Region,* https://www.brattle.com/wp-content/uploads/2024/09/Value-of-Lost-Load-Study-for-the-ERCOT-Region.pdf

these links, as well as how those production cost savings experience diminishing marginal returns as transmission expansion reduces marginal production cost differences between regions.[28] While LBNL's analysis is based on Locational Marginal Prices (LMPs), this should be a close proxy for production cost savings as marginal prices are typically set based on the marginal production cost of the marginal resource in each geographic location.

LBNL's analysis calculates a saturation effect for expanding ties between regions, which was also incorporated into our analysis. This accounts for the inherent diminishing marginal returns from incrementally larger ties between two regions, reflecting that prices in the region receiving power decline as that region moves down its supply curve, while prices in the region delivering power increase as that region moves up its supply curve. LBNL calculates a percentage by which savings are reduced on average for the first 1,000 MW of ties between two regions, relative to the marginal savings for the first incremental expansion of ties between those regions. We assume that reduction increases linearly with tie expansions larger than 1,000 MW. For the hypothetical example of a regional pair for which LBNL calculates a 15% benefit reduction for the first 1,000 MW tie, and for which the ITCS recommended an increase in transfer capacity of 2,500 MW, the calculated price difference was reduced by 15% for the first 1,000 MW, 30% for the second 1,000 MW, and 37.5% for the last 500 MW of expanded ties.

We used other data sources to fill in prices that were not available in LBNL's analysis. In particular, LBNL did not include prices for Southern Company or Florida. However, S&P reports an index reflecting a daily average price for Florida, which was used to estimate production cost savings for the expanded tie between Southern Company and Florida.

In some cases the regions from the ITCS do not map perfectly to the regions LBNL used in its analysis, and LBNL did not report a supply curve slope for some regional pairs. In these cases we attempted to choose regional pairs in LBNL's analysis that most closely approximate the regions in the ITCS.

To avoid double-counting with the value of lost load benefit calculated above, we did not account for production cost savings during the regional generation shortfall events identified in the ITCS. This was done by calculating the average locational marginal price during historical weather periods that resulted in a loss of load in the ITCS, multiplying that average price by the MWh of lost load mitigated by the transmission in the ITCS, and then subtracting that from the production cost savings calculated using the method above. This reduced the calculated production cost savings by $355 million per year. Our analysis simply removed the production cost savings from the receiving region in those hours, which conservatively assumes the power to mitigate the loss of load was provided at no cost by a neighboring region. In reality that power would have had some cost, which would have reduced the amount subtracted from the production cost savings for those hours. This assumption was made to ensure our results were conservative and to avoid complexity in determining which neighboring region supplied the power and at what cost.

28 J. Kemp *et al.*, *Electric transmission value and its drivers in United States power markets*, https://www.researchsquare.com/article/rs-3957695/v1

Generator cost savings

Distinct from production cost savings, another benefit of transmission is that it provides regions with access to more productive generating resources. Transmission provides access to all types of lower-cost energy sources, though fuel cost savings from accessing real-time differences in marginal production costs between regions are captured in production cost savings. Our calculation of generator cost savings solely accounts for the fact that one can obtain the same amount of generation with less generating capacity and thus cost by building wind and solar generation in regions with more productive resource areas. This was accounted for by comparing the levelized cost of wind and solar generation in the two regions connected by a transmission line. The levelized cost calculations and assumptions were taken from the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB),[29] and include the value of federal production tax credits for wind and solar generation. Average capacity factors for recent wind[30] and solar[31] projects in the two connected regions, calculated by Lawrence Berkeley National Laboratory using Energy Information Administration generation and capacity data, were incorporated into the levelized cost calculation. This benefit was not calculated for expanded ties between regions with similar quality wind or solar resources.

Transmission cost

The cost of a transmission expansion large enough to provide the increase in transfer capacity identified in the ITCS was estimated for each regional pair. In most cases, cost and transmission capacity assumptions were taken from MISO's Transmission Cost Estimation Guide For MTEP24.[32] This includes terminal costs for AC substation upgrades or High Voltage Direct Current Voltage Source Converters, and per mile costs for new transmission lines. In some cases the assumed line distance and configuration was informed by projects that have been proposed. These cost calculations are shown in Table 4.

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29 NREL, *Annual Technology Baseline,* https://atb.nrel.gov/

30 LBNL, *Land-Based Wind Market Report,* https://emp.lbl.gov/wind-technologies-market-report

31 LBNL, *Utility-Scale Solar,* https://emp.lbl.gov/utility-scale-solar

32 MISO, *Transmission Cost Estimation Guide For MTEP24,* https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf

TABLE 4 | Transmission cost assumptions and calculations based on MISO estimates

Region 1	Region 2	MW	AC/DC	kV	Line mile	Line cost ($M)	Term. cost ($M)	Total cost ($M)	Annual cost ($M)	$/W
Front Range	ERCOT	5700	DC	640	280	1540	1828	6400	513	1.1
MISO S	ERCOT	4300	DC	500	640	1792	2480	4592	368	1.1
SPP S	ERCOT	4100	DC	500	150	420	2480	2973	238	0.7
Front Range	SPP S	1200	DC	400	290	783	922	1364	109	1.1
SERC SE	MISO S	300	AC	500	30	132	26	18	1	0.1
PJM W	MISO E	1000	AC	345	70	245	17	146	12	0.1
SERC SE	SERC FL	1200	AC	500	50	220	52	126	10	0.1
PJM W	SERC E	1600	AC	500	50	220	52	168	13	0.1
SERC C	SERC E	300	AC	230	100	220	11	263	21	0.9
SERC SE	SERC E	2200	AC	500	100	440	26	395	32	0.2

In many cases the modeled transmission expansion was somewhat larger or smaller than the identified need. In those cases the total cost was scaled proportionally to meet the need, on the assumption that the cost of the extra capacity could be recovered in the market. As a result, the “total cost” reported in Table 4 above may differ from the sum of the line cost and terminal cost. As noted in the report text above, the cost and benefits of transmission ties between NYISO and Canada and ISONE and Canada were not included as LBNL did not calculate production cost savings for ties with Canada.

TABLE 5 | Interfaces for which transmission cost estimates were based on real projects

Regional tie	Real-world project used for cost estimate
California North – Wasatch Front	SWIP-North
MISO West – SPP South	JTIQ
MISO West – MISO East	Helix to Hiple upgrade from MISO Tranche 1
PJM East – PJM South	Maryland Piedmont Reliability Project
PJM East – NYISO	Neptune, with costs assumed to double since 2005

Transmission investment costs were depreciated over 30 years, consistent with their tax treatment,[33] with costs annualized using the nominal Weighted Average Cost of Capital of 6.95% assumed for 2029 in NREL ATB.

CONCLUSION

Building on the ITCS, this paper quantifies several of the economic benefits provided by the interregional transmission expansion recommended in the ITCS. Our analysis shows that the benefits of the transmission investment far outweigh the costs, even without fully accounting for all of the benefits of transmission. **Each $1 invested in the transmission expansion recommended in NERC's ITCS would yield benefits of $4.30 to $5.80, with a payback period of less than three years.** More specifically, while the proposed transmission investments in the ITCS would cost around $1.8 billion per year, **they would deliver annual benefits to ratepayers ranging from $7.8 billion to $10.6 billion**. An optimal transmission expansion that maximizes all benefits, and not just electric reliability which was the sole focus of the ITCS, would be far larger than that identified in the ITCS.

33 Onvio, *MACRS asset life table,* https://onvio.us/ua/help/us-en/staff/fixed-assets/depreciation/macrs-asset-life-table.htm

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