Empirical Estimates of Transmission Value using Locational Marginal Prices

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Contents

High-Level Findings

Transmission Links Have Significant Economic Value

- Interregional and regional transmission links reduce congestion and expand opportunities for trade.
- Nodal real-time wholesale power prices exhibit stark geographic differences that are, in many cases, stable overtime and can be used to estimate transmission value.
- Many links have hourly average pricing differences that exceed $15/MWh – equivalent to $130 million per year for a 1000 MW link.
- Interregional links ($24/MWh in the median case in 2021) have greater value than regional links ($11/MWh in the median case in 2021) – though many high-value regional links exist.

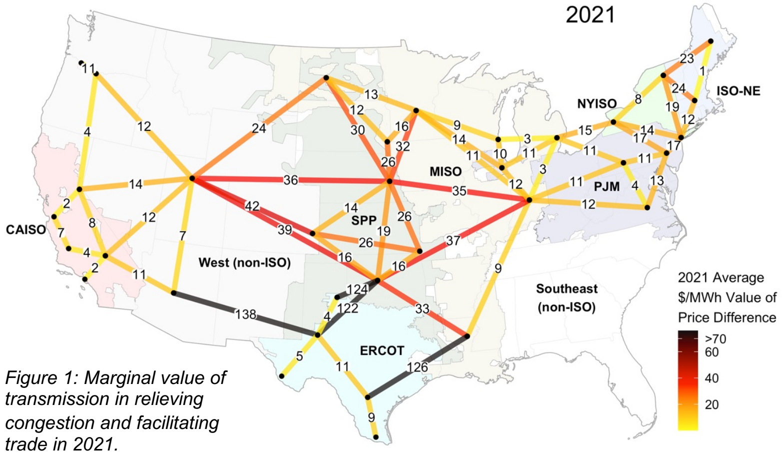


Figure 1: Marginal value of transmission in relieving congestion and facilitating trade in 2021.

Transmission value is correlated with energy prices and varies by region and year

- Congestion has gotten worse for links connected to SPP and ERCOT.
- Value of transmission is variable overtime, and often spikes in the event of extreme conditions like the 2014 Polar Vortex and 2021 Winter Storm Uri.

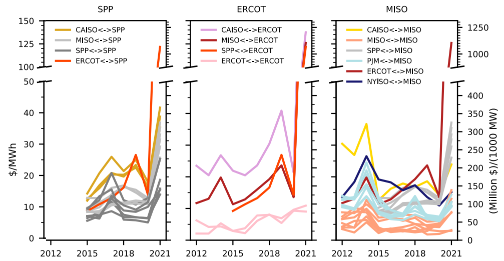


Figure 2: Marginal value of transmission overtime for links across a subset of ISOs/RTOs.

Extreme conditions and high-value periods, which are difficult to model, play an outsized role in the value of transmission

- 50% of transmission's congestion value comes from only 5% of hours.
- Existing transmission planning approaches run the risk of understating the economic value of new transmission infrastructure by inadequately modeling such periods.
- These findings are driven not only by historical weather events but also 'normal' market occurrences such as infrastructure outages, fuel price volatility, forecast errors, and electric demand volatility.

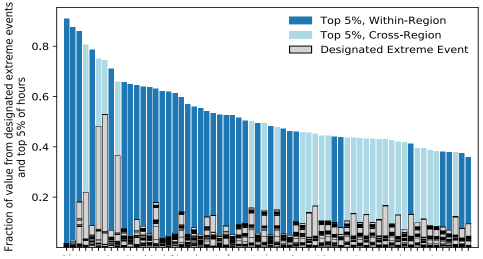


Figure 3: Fraction of marginal congestion relief value in top 5% of hours and during designated extreme events from 2012 through 2021. Each bar represents a different link represented in Figure 1. The specific path labels of the transmission links are found on slide 28.

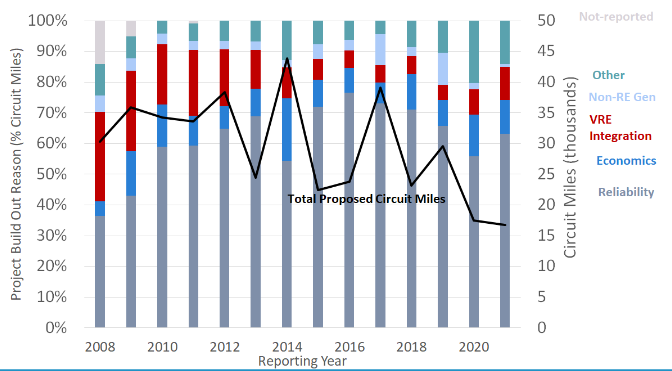
Introduction and motivation

- Transmission can help reduce the system-wide costs of supplying electricity and provide other benefits such as improving grid reliability and resiliency.
- The decision to build or not to build transmission depends on cost benefit tradeoffs.
- Estimating these costs and benefits is challenging and complex.
- Often, transmission planning focuses on a narrow subset of benefits, primarily related to reliability benefits.
- To help provide information about economic benefits beyond reliability we analyze the congestion value of transmission, an important piece of the larger suite of transmission economic benefits.
- The congestion value of transmission derives from facilitating the use of a lower cost set of generators to meet demand.
- We focus on congestion value for three reasons:
  - Congestion value is related to production cost savings, which is a large and commonly estimated benefit of transmission.
  - By using empirical data, our analysis accounts for the congestion relief benefits of transmission as experienced historically, inclusive of extreme weather and other high value conditions (e.g., generator or infrastructure outages, regional fuel cost volatility, etc.).
  - Forward-looking models of production cost and congestion savings are challenged in projecting value during more extreme weather conditions and other high value conditions.
- Our analysis of congestion value using historical pricing patterns provides context and quantifies trends in this important transmission economic benefit.

General context: Transmission planning challenges

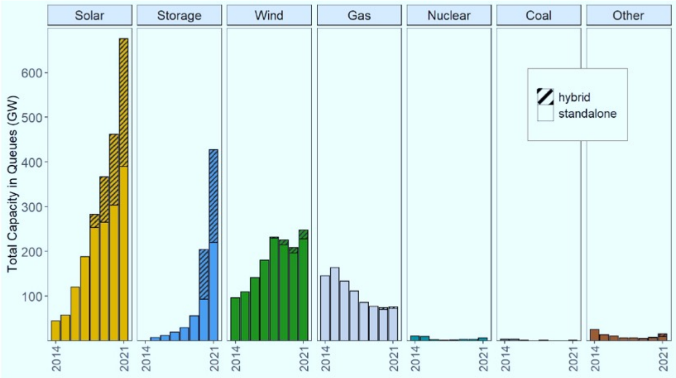
- Recent Federal Energy Regulatory Commission (FERC) Rule Makings processes (i.e., NOPRs) – identify a problem that an increasing portion of transmission planning is occurring through localized reliability or generator interconnection processes, rather than a more ***cost effective, long-term, regional and inter-regional*** planning framework.
- Since 2008, reliability has been the *primary* motivator for 62% of new transmission proposed, based on circuit miles (or 80% based on project count). Direct economic benefit is the primary motivator for only 11% or 5% based on proposed circuit miles or project count. These numbers are based on data compiled by NERC (see figure top right).
- The figure to the bottom right shows that many hundreds of gigawatts of new generator capacity is currently under study with in the interconnection queues. The volume of new capacity within in the queues is one of the drivers for the recent FERC NOPR actions.
- Insufficient transmission planning and coordination can negatively impact, or add cost to, the electricity system in various ways.
  - Increases total cost of electricity supply to load.
  - Degrades reliability and resilience of power delivery.
  - Strains achievement of near- and long-term public policy goals.
  - Increases generator interconnection wait times and/or generator integration costs.
- An important challenge in transmission planning and coordination is estimating the full range of benefits that transmission investments provide and to whom those benefits accrue.

Total U.S. transmission 10-year proposed buildout.



Source: Updated figure based on: Gorman et al. (2019) "Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy" *Energy Policy*, https://doi.org/10.1016/j.enpol.2019.110994; or see NERC data https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

Generators in development seeking interconnection



Source: Rand et al. (2022) "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021" Lawrence Berkeley National Lab. (LBNL). https://doi.org/10.2172/1864543

General context: There are many types of transmission benefits

- Transmission investment benefits can be broadly bucketed into three areas:

  (1) grid operations, (2) system planning, and (3) non-market benefits

- Many transmission expansion analyses only consider a subset of these benefits and rarely incorporate analysis over wide inter-regional boundaries.

- Our study focuses on congestion value and quantifies the benefits of the first two two bullets of the grid operations area.

Grid Operations

- Production cost congestion savings under normal ***and*** extreme conditions
- Mitigation of weather, load, and variable generation uncertainty
- Reduction in operating reserves
- Increased competition and market liquidity

System Planning

- Deferred/avoided grid capacity investments
- Allowing development of new, low cost power plants which otherwise might be precluded due to location constraints
- Increased grid hardening/resilience

Non-Market

- Improved utilization of transmission corridors
- Reduced cost of meeting public policy goals
- System-wide emissions reductions

*Typically unquantified benefits in current transmission planning approaches

Key supporting literature

- The primary benefit driving development of most transmission projects is reliability as opposed to direct economic benefit [*Ref 1*]. This does *not* imply that all direct economic benefits are ignored, but does imply that direct economic benefits are often not the primary focus of planning analysis.

- *Refs 2-5* raise concern about many transmission benefits that commonly go unquantified in planning processes. *Refs 2 and 3* suggest that while there have been a limited number of important multi-value transmission planning efforts, most transmission planning processes consider only a limited set of the benefits. *Refs 2-5* detail specific benefits that are typically not quantified in planning processes.

- *Refs 4-5* describe the challenges that prospective modeling systems have in accounting for extreme events and or unexpected grid conditions such as infrastructure outages. Ref 4 details the limitations of current transmission planning processes in representing the value of transmission given uncertainty in load and generation forecasts, especially when these processes depend on deterministic hourly simulations.

- More generally, representation of extreme events within electric system modeling, and transmission planning specifically, is an area of active research. [*Refs 6 – 9*]

References (*note: reference numbering resets each page*):

1. Gorman et al. (2019) "Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy" *Energy Policy*, https://doi.org/10.1016/j.enpol.2019.110994; or see NERC data https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx
2. Pfeifenberger et al. (2021) "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs" The Brattle Group/Grid Strategies, https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/
3. Pfeifenberger et al. (2021) "Roadmap to Improved Interregional Transmission Planning" The Brattle Group. https://www.brattle.com/insights-events/publications/brattle-economists-author-report-on-the-benefits-of-expanding-interregional-transmission/
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8. Orford (2020) "Tools for Regulators in a Changing Climate: Proposed Standards, State Policies, and Case Studies from the Western Grid" *Geo. Envtl. L. Rev.*, https://digitalcommons.law.uga.edu/fac_artchop/1357
9. Goggin M., (2021) "Transmission Makes the Power System Resilient to Extreme Weather" Grid Strategies. https://acore.org/transmission-makes-the-power-system-resilient-to-extreme-weather/#:~:text=The%20analysis%20finds%20that%20each,Uri%20in%20February%20of%202021.

Goals and scope

- Our goal with this analysis is to examine historical pricing trends and spatial differences to gain insight into possible transmission benefits that are often overlooked.
- This analysis does not provide a comprehensive estimate of transmission value.
- The analysis does provide new insight into one portion of total transmission value: the value of congestion relief, or the arbitrage value of linking two locations with different prices, including during more extreme grid conditions and high value hours.
- There are important limitations to this analysis, which are stated throughout the document.

Approach

This report builds on past work, for example *Ref 1* examined congestion in wholesale markets through RTO/ISO-reported congestion costs. These reported congestion costs are presented only at the region-wide level, and do not provide insight into where congestion is most costly within each region, and also do not provide insight into the value of interregional transmission. Additionally, RTO/ISO reported congestion metrics are challenging to compare to each other because each RTO/ISO has a different approach to calculating these metrics.

Ref 1 also examined transmission line usage rates in the western United States, finding high usage of a certain number of transmission lines. Our analysis goes beyond this past work by analyzing and identifying congestion across all nodes within each region and providing a metric to examine the value of interregional transmission. In this analysis, we examine price differences within and across energy markets to understand trends in congestion and the implications for transmission expansion.

1. United States Department of Energy (DOE), (2020) “National Electric Transmission Congestion Study”. https://www.energy.gov/oe/downloads/2020-national-electric-transmission-congestion-study

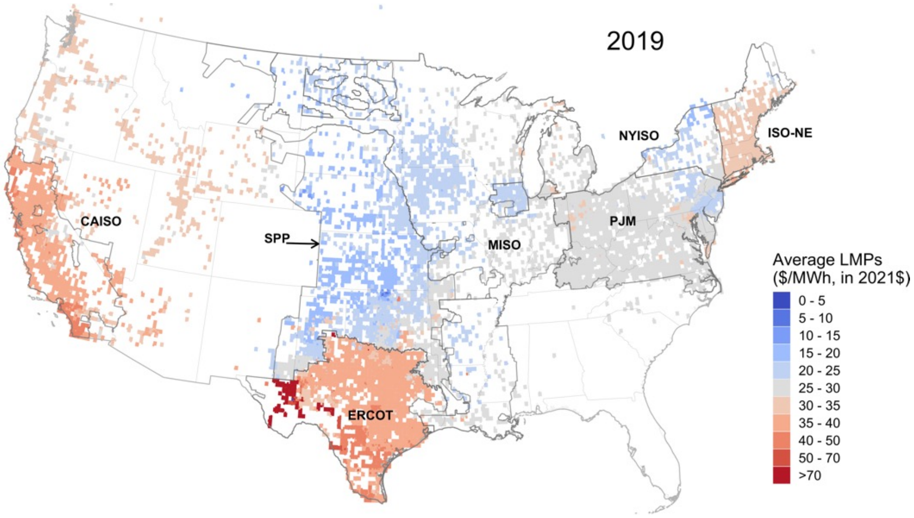
Our analysis depends on recorded, real-time, hourly, nodal prices in wholesale markets. Nodal prices represent the marginal cost of the last unit of electricity (in units of $/MWh). The wholesale markets comprise seven major Independent System Operator (ISO) regions, in some cases called Regional Transmission Organizations (RTOs). Hereafter, we will refer to these regions as ISOs as the differences between ISOs and RTOs are not critical for this analysis.

The seven major ISOs included in this analysis are the California ISO (CAISO), Southern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO (MISO), PJM RTO (PJM), New York ISO, and ISO New England (ISO-NE). Additionally, the Western Energy Imbalance Market (WEIM), managed by CAISO, is included in the analysis and CAISO and WEIM are treated as a single region.

Nodal prices are reported by each ISO and we purchase records of these prices from a commercial vendor, the product is called Velocity Suite, by Hitachi.

Approach: Analyze local hourly electricity prices

- Analysis of real-time nodal electricity price (LMP) differences provides an indication of transmission value and how it varies.
- We examine within-region and interregional variability as well as how spatial differences in price vary over years.
- Historical pricing represents actual operating conditions within the system and thus allows for analysis of extreme events and high value hours that are difficult to model.
- Key limitations:
  - Pricing differentials only represent a portion of the benefits of transmission investment.
  - Historical values do not necessarily reflect values under changing or future market conditions.
  - We analyze “marginal” prices, thus the transmission values calculated are subject saturation effects. In other words, the value of new transmission would decline as transmission capacity is deployed. This analysis does not explore the depth of the market, only the marginal value.
  - Value here represents energy markets, but many regions include capacity markets as well. Capacity value is not included in this analysis.
  - Some differences in pricing between regions is due to differences in market rules and structure rather than lack of transmission. Our assumption is that lack of transmission represents a large majority of differences in pricing between regions, but we have not quantified the other causes of price differences.



The figure above shows the average hourly price at individual nodes in 2019 (i.e., the Locational Marginal Pricing or LMP). There are over 50,000 individual nodes in the seven wholesale markets and energy imbalance areas administered by ISO/RTOs. The prices shown are the real-time prices.

Real versus nominal dollars: All dollar values shown throughout this document have been converted to the 2021 dollar year based on the Consumer Price Index.

Estimating Transmission Value with Locational (Nodal) Market Prices (LMPs)

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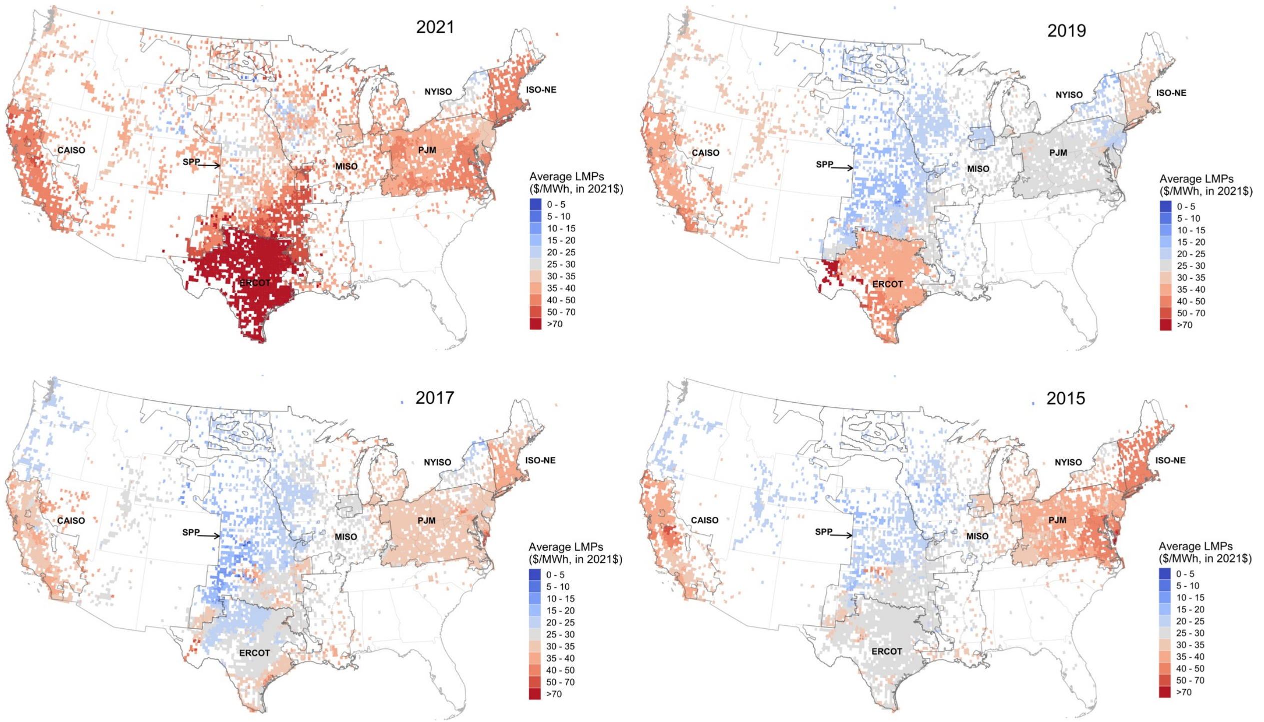
Annual average real-time nodal wholesale electricity prices vary strongly by year and location



These figures show average annual real-time nodal prices in the wholesale markets administered by the seven ISO/RTOs
Note: The interactive tool ReWEP allows users to further explore empirical trends in wholesale pricing patterns: https://emp.lbl.gov/renewables-and-wholesale-electricity-prices-rewep

- This slide provides basic context about geographic variation in electricity prices. Analyses presented in later slides will investigate transmission value and congestion on an hourly basis.
- The prices shown are real-time energy prices, and in general, a reminder that this analysis will focus on the value that transmission can provide through geographic arbitrage of energy prices. This is a subset of the total potential value of transmission, and does not include capacity value, reliability value, or other categories, as discussed in the prior slides.
- Beyond the clear difference in price between years, one can observe spatial gradients in prices both within regions and across regions.
- The following slides pull out these spatial gradients, which are sometimes challenging to observe in the simple annual average price figures.
- The value indicated by differences in annual average prices is a lower bound. For example, two locations could have the same average annual price, but could still derive value from transmission if their high and low priced hours occur at different times from each other.

Within-region congestion: Annual average pricing gradients are observed in each ISO

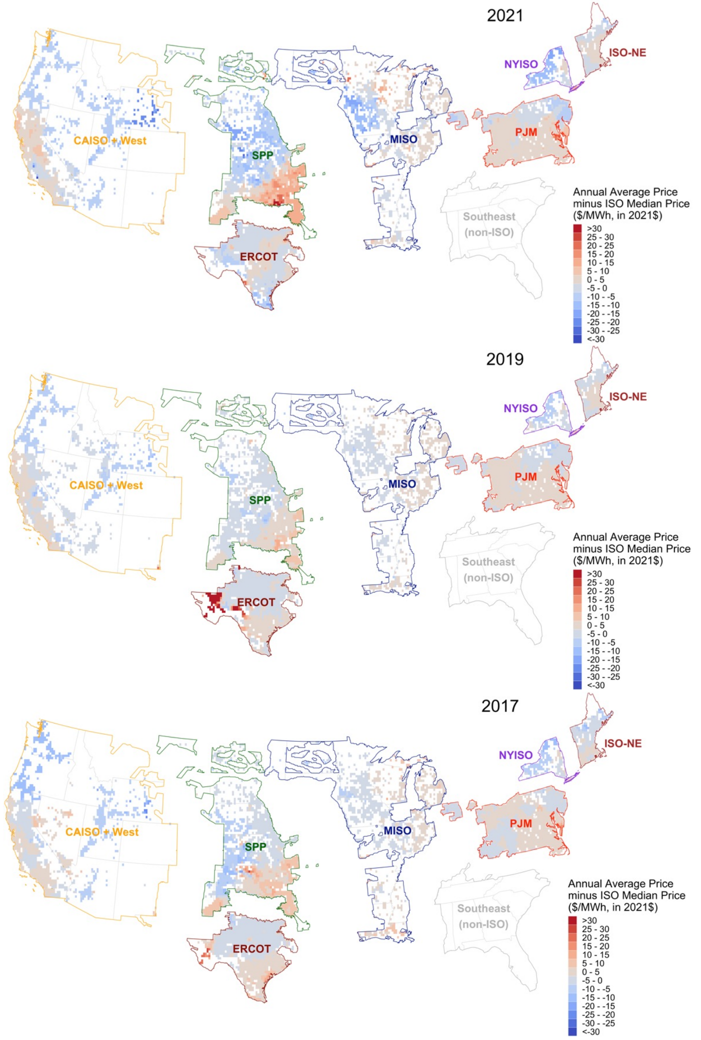
- Within-region spatial gradients in annual average pricing are relatively stable over time compared to the annual average prices displayed on the previous slide.
- While a region's average price may see year-to-year variability in response to a number of factors (e.g., natural gas prices, weather conditions) the within-region spatial gradients appear to maintain similar directionality over time in most locations.
- As mentioned, these gradients represent a lower bound of congestion impacts as they are based on annual prices.
- Because the median price is different in each ISO, this figure does not provide insight into interregional congestion.
- New transmission could help to lower electricity costs in high priced regions.

These figures were created with a two-step process:

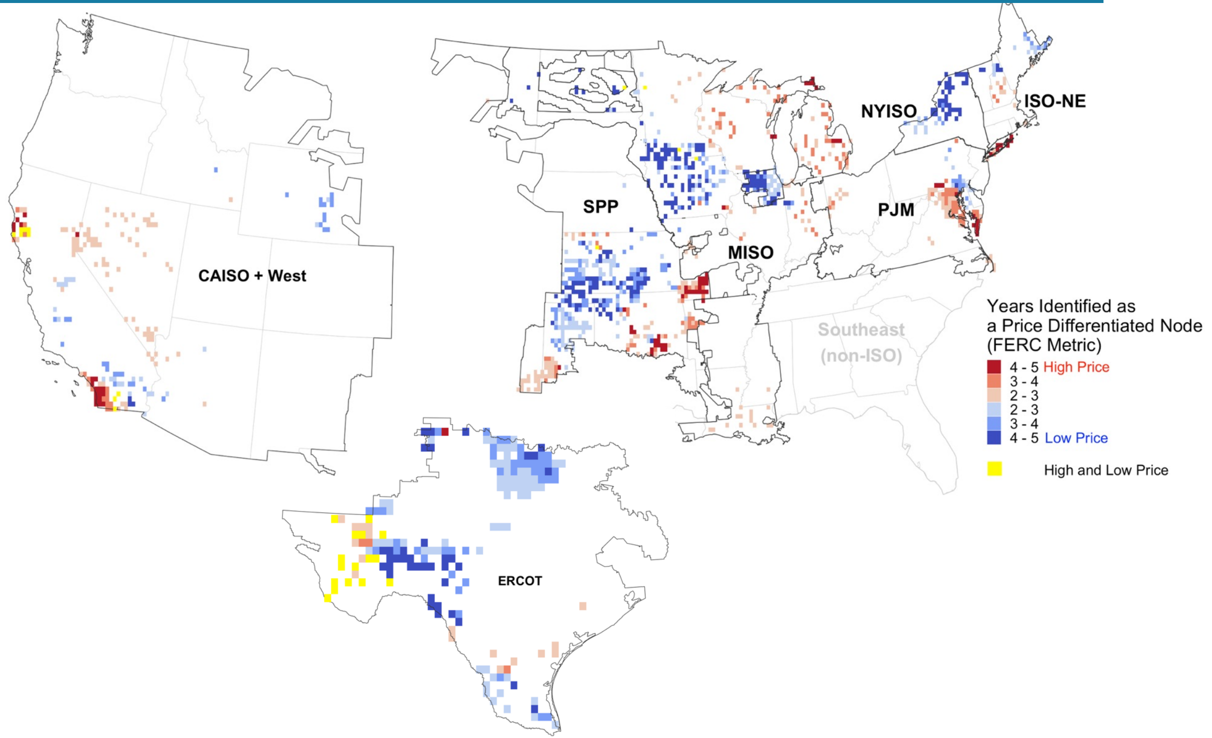
1. The median annual average price was found for each ISO
2. This median price was subtracted from each node's annual average price

Notes:

- CAISO and the larger western region are treated as a single region.
- Nodal price analysis does not provide full geographic coverage of congestion through the non-RTO western region (especially true in New Mexico and Colorado, but also in portions of other states as well).
- Similarly, the analysis provides no coverage of non-ISO regions in the Southeast.



The Market Price Differential Metric: To identify locations with high or low price extremes that occur in multiple years between 2017 – 2021



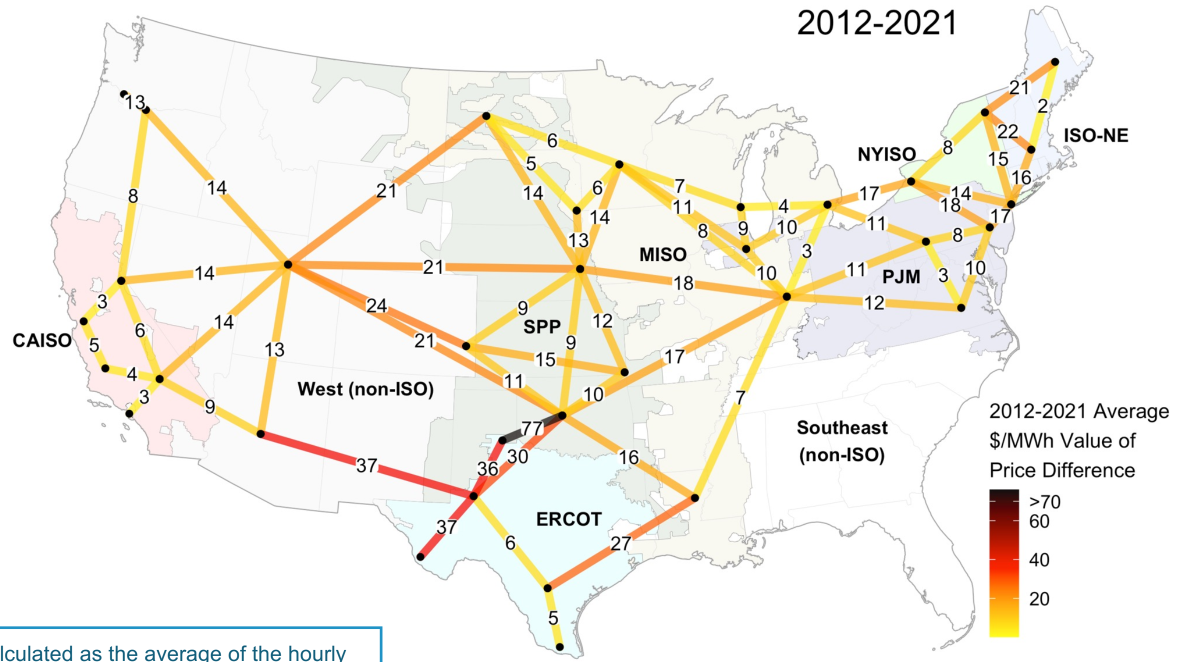
- This metric isolates locations in each region that tend to have higher than average high prices or lower than average low prices.
- It does not depend on annual average prices, but instead identifies locations based on particularly low or particularly high hourly prices. For example, a location would be selected as a 'high price' location if its price consistently spiked above more typical high priced hours throughout the rest of the region.
- This metric can help to isolate locations that are strongly impacted by congestion and help to identify within region opportunities for transmission. As in the prior slides, within-region links between high price and low price locations may indicate opportunities for transmission to reduce cost in high priced regions.
- A list of high and low priced regions identified with this metric is presented in the appendix.
- Darker colors indicate consistency over time. The darker reds and darker blues indicate that a location is high or low priced for 3 to 5 years out of the 5 year sample.
- Note that this metric is not a direct measure of transmission value and that other strategies (energy efficiency or new low cost energy supply resources, for example) could also help lower localized high prices.
- Finally, note that SPP, MISO, PJM, NYISO, and ISO-NE were treated as a single region in this case. However, if calculated separately, the resulting distribution of high and low price locations looks almost identical.

Each node is evaluated based on its 95th and 5th percentile price hour each year, which is compared to regional average 95th and 5th percentile of hourly prices. Additional details can be found in the appendix.

This approach was originally developed by FERC: Federal Energy Regulatory Commission (FERC) (2016) "Transmission Metrics: Initial Results, Staff Report" AD15-12-000. https://www.ferc.gov/sites/default/files/2020-04/03-17-16-report_0.pdf

Marginal value of transmission in relieving congestion in 2012-2021 (in $/MWh Units)

- Each link in this figure shows transmission value derived from relieving congestion over the listed time period (details below)
- Value range: $2/MWh to $77/MWh.
- Equivalent to: 20 to 670 million dollars per year for a 1000-MW capacity line (average annual value over 2012 – 2021).
  - see next slide for a figure with alternate units.
- Relatively high value links are found in many regions.
- High value links to the Texas panhandle and Texas Big Bend region are valuable due to unusually high values found in 2018 and 2019 at these locations. Extreme events are discussed more generally in the next section.
- Caveat: These are marginal values – these transmission links would face value saturation as capacity increased. The point at which value would meaningfully saturate would depend on location specific conditions, and is possibly less than 1000 MW in some cases.
- Caveat: These values represent only the hourly arbitrage value between the two locations on either side of each link. They do not provide a comprehensive estimate of transmission value.
- Only values are presented, costs are not calculated, but value is not particularly correlated with distance (though cost is also not perfectly correlated with distance).



The energy market value of selected hypothetical transmission links is calculated as the average of the hourly absolute value of the difference in prices between locations over the selected period.
Prices in SPP were only available starting in 2015 and value for SPP links is calculated starting in 2015.
Note that the node located west of the SPP boundary in Colorado is administered by SPP, while the other nodes in the West (non-ISO) region participate in a market administered by CAISO.
ORDC prices are included in ERCOT prices, which contributes to the value of interregional links into ERCOT.
Reminder: All dollars are shown in 2021 dollar year.

Marginal value of transmission in relieving congestion in 2012-2021 (in $/1000 MW-year units)

- Each link in this figure shows transmission value derived from relieving congestion over the listed time period (details below).
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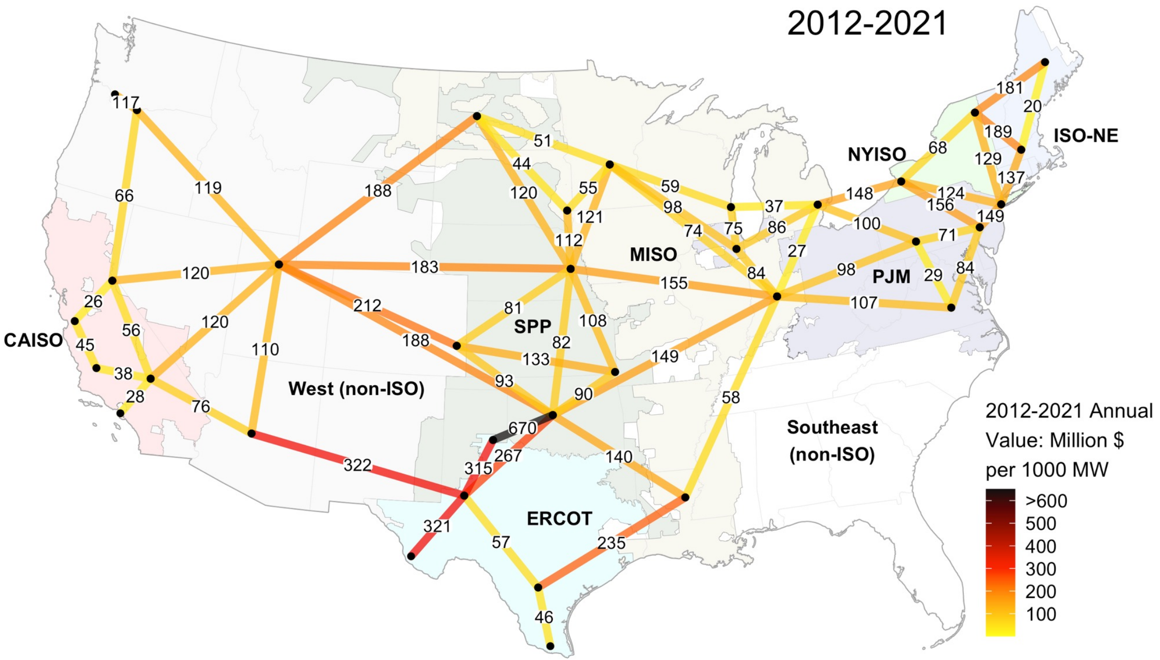
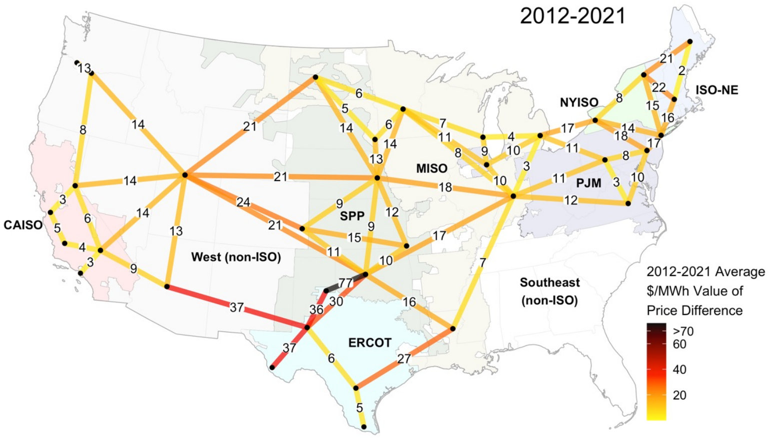
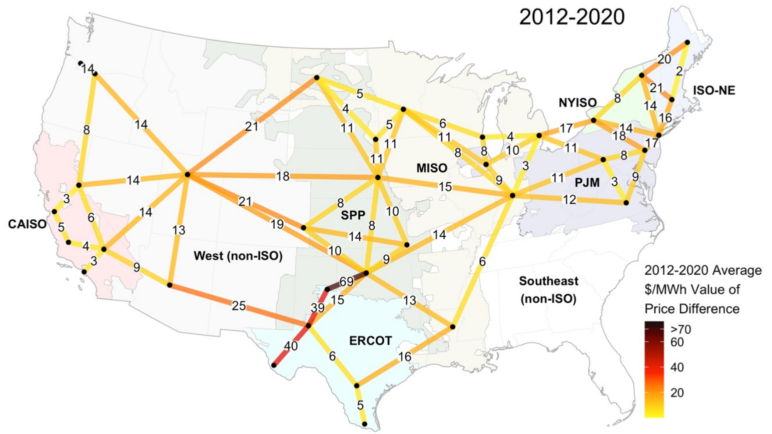


The energy market value of selected hypothetical transmission links is calculated as the sum of the hourly absolute value of the difference in prices between locations over the selected period. The sum is then multiplied by 1000 (representing 1000 MW of capacity) and divided by the years in the selected period.

Marginal value of transmission in relieving congestion in 2012-2020 vs. 2012-2021 (in $/MWh)

- The figures to the right allow for a comparison between the 2012 – 2021 average value and the 2012 – 2020 average value.
- The purpose of comparing these two time frames is to determine how influential the unique conditions that occurred in 2021, especially winter storm Uri, are to the long term average values.
- Including 2021 does increase the long-term value of some of the links. The long-term average of a number of links in SPP increased by 10% to 20% just from inclusion of 2021.
- Most links in other regions were less sensitive to the inclusion or exclusion of 2021 from the long term average.

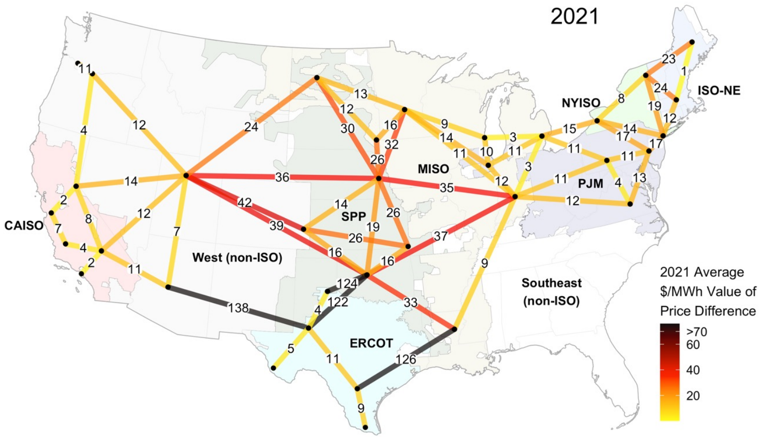


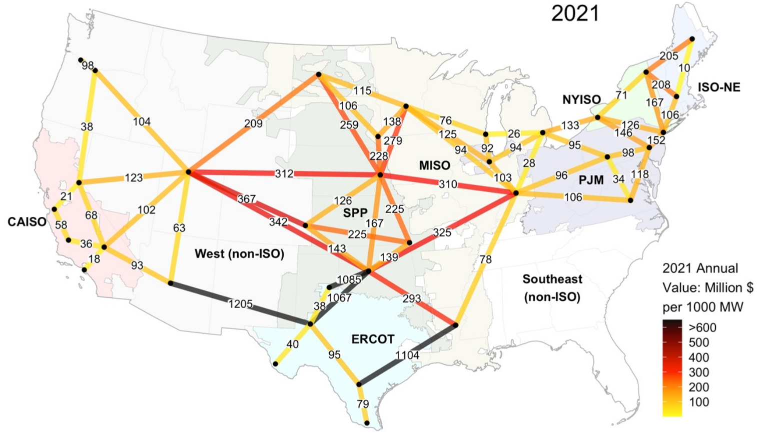


The two figures here are only presented in $/MWh terms (as opposed to also in $/1000-MW-year units), but the primary goal of these figures is to compare the long term average value of the links with and without including 2021.

Marginal value of transmission in relieving congestion in 2021

- In 2021, most values were similar to or higher than the past decade's average.
- In 2021, the most valuable within-region connections are found in SPP and NYISO.
- In 2021, the most valuable interregional connections are between SPP and its neighbors, and ERCOT and its neighbors.
- In some, but not all cases, the location of the highest-value transmission links matches expectations based on the more general indicators shown in the earlier slides.



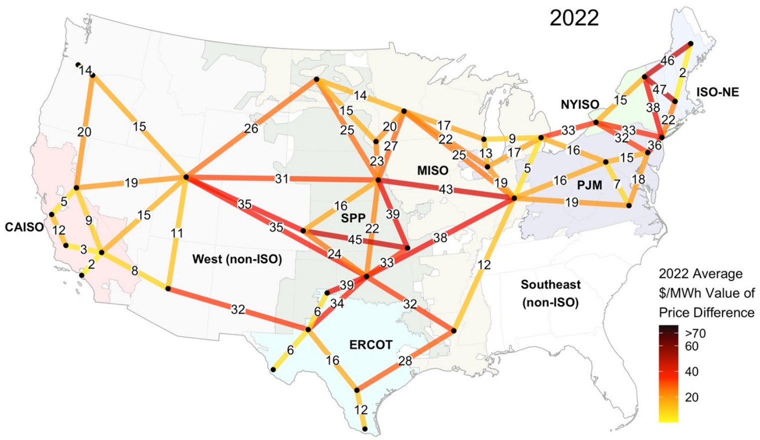


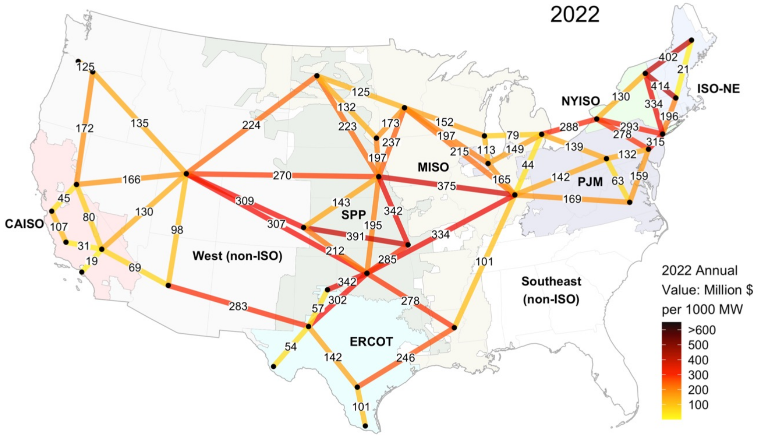
These figures show the same values in different units.

Marginal value of transmission in relieving congestion in the first half of 2022

- YTD 2022 transmission values are similar or higher to 2021 even without similarly extreme weather events.
- The exception are interregional links into ERCOT. These links have lower value in 2022 than in 2021, links into and within SPP have maintained high values into 2022.
- Links in the northeast and northwest of the U.S. also have high values in the first half of 2022.
- Note that the $/1000 MW-year values are annualized values based on price data for the first half of the year. In other words, they are the value summed over the first half of the year multiplied by two. Similarly, the $/MWh units are simply the average value calculated over the first half of the year.
- Caveat: These values have not been adjusted for seasonality. Actual 2022 transmission values between locations will differ if the value for the second half of the year differs substantially from the first half of the year.

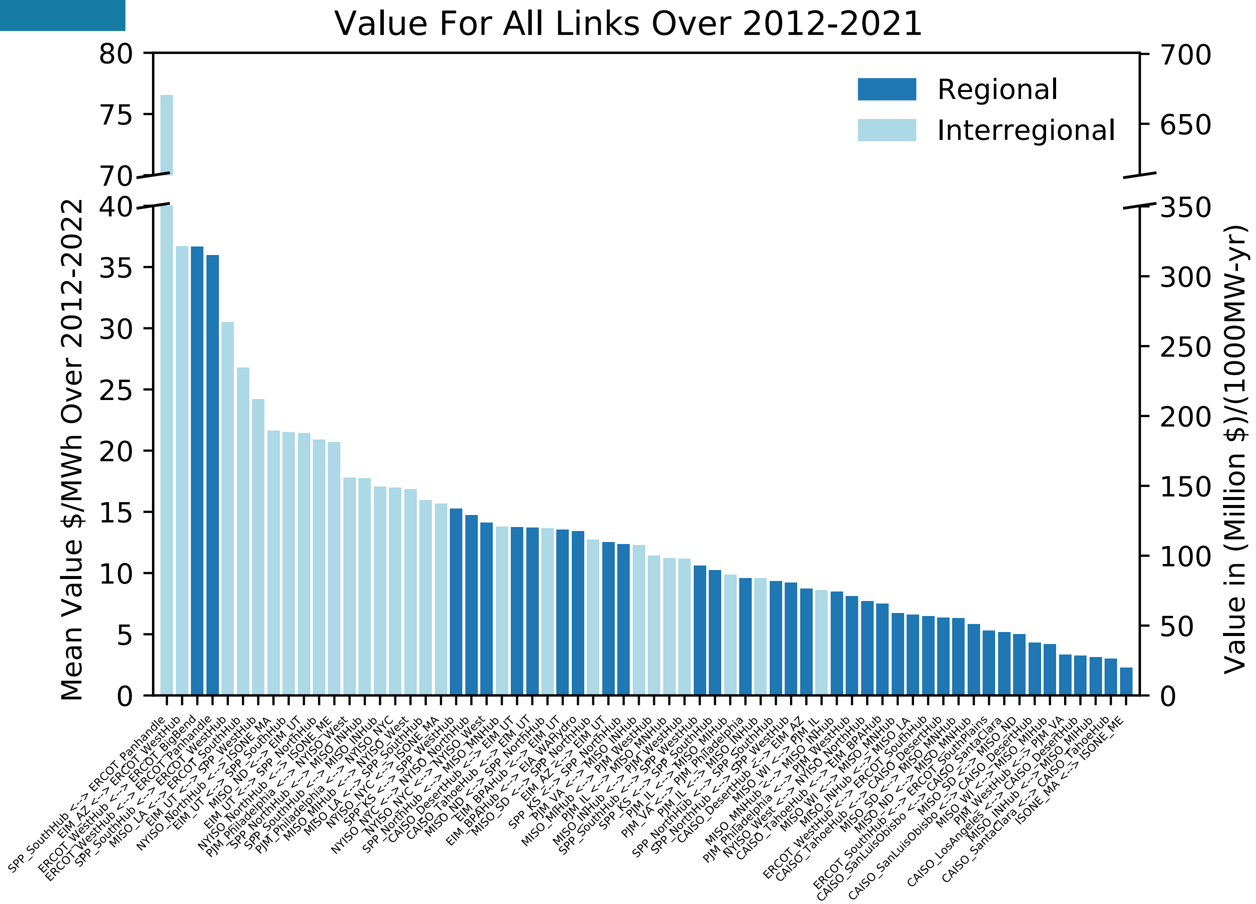
These figures show the same values in different units.
For comparison with the previous figures, these figures are shown with dollars deflated to the 2021 dollar year based on the consumer price index (specifically, nominal values in 2022 were deflated by 8% to be presented as 2021$).





Value for regional and interregional links

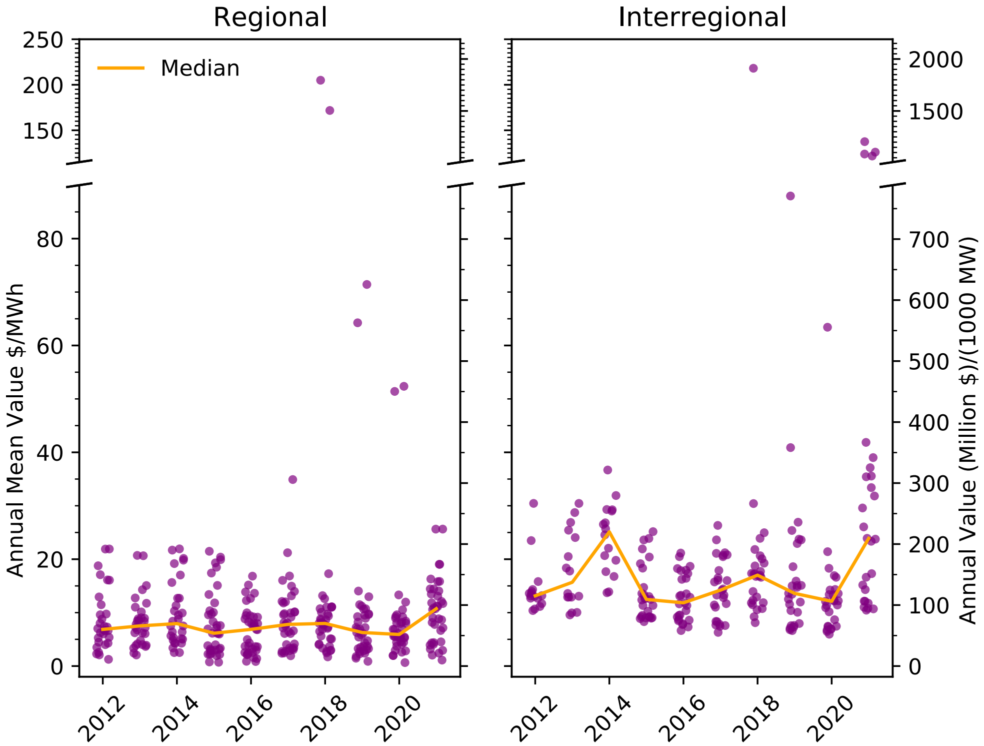
- Interregional links are usually, but not always more valuable than within-region links.
- Interregional links may have higher value due to more diversity of weather, load profiles, and generator resources than is found within regions.
- The value of certain links is much larger than others with the most valuable links averaging 5 to 10 times that of lower value links over the full time period.



This figure shows the distribution of value across each transmission link shown in the prior figures.

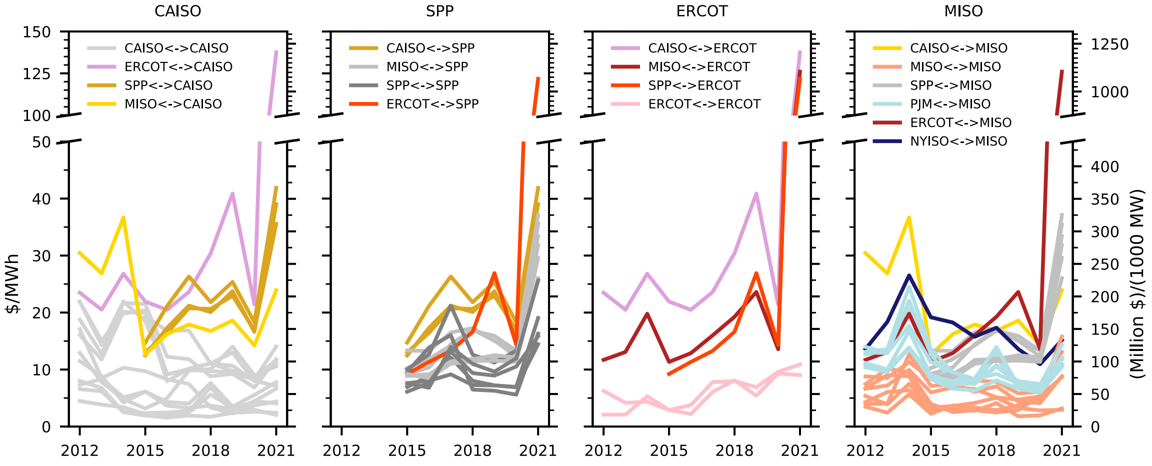
Value for regional and interregional links over time

- These plots show the distribution of annual value across the set of links.
- The presence of the outlier values (circles) in multiple years shows that individual links can accrue substantial value in single years even if the median or average value across all the links is average or low for that particular year.
- For example, there are multiple links for which their value in individual years was ~10x or greater than in other years.
- The highest annual median value for the within-region links is roughly twice that of the lowest annual median value ($11/MWh vs. $6/MWh).
- Similarly, the highest annual median value for the interregional links is roughly twice that of the lowest annual median value ($25/MWh vs. $12/MWh).

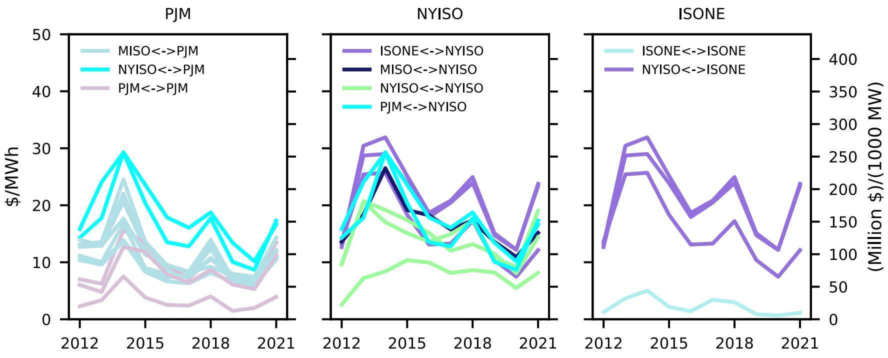


These figures show the distribution of value across the set of transmission links.
Reminder: All dollars are shown in 2021 dollar year.

High value links occur in different regions in different years



- Values are variable from year to year and different regions have peak values in different years.
- For example, ERCOT and SPP values peak in 2021 (associated with the winter conditions in February of that year) but PJM values peak in 2014 (associated with the polar vortex of that year).
- Values also tend to be correlated with overall wholesale prices, for example, declining in 2020 across most regions and increasing in 2021 across most regions.
- A number of links in ERCOT and SPP show an upward trend that begins prior to 2021.
- Overall the unpredictable variation in wholesale prices and extreme conditions makes it challenging to pick out trends in the value of transmission links. But it is clear that extreme conditions in a single year, or even season, can materially increase the 10-year value of a link.

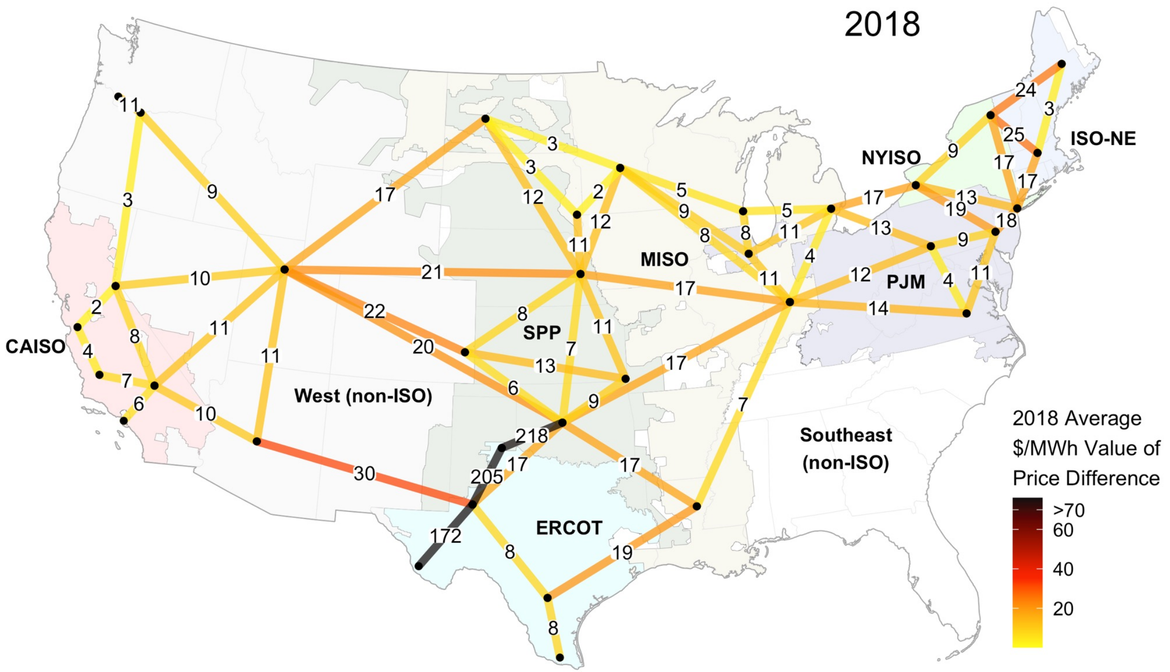


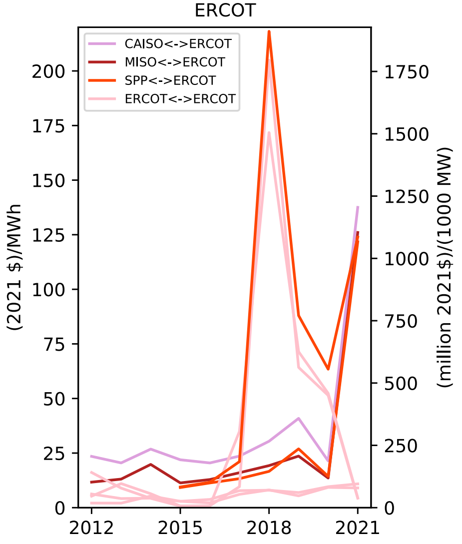
These figures present the annual value in (2021$)/MWh (left ticks) and (millions 2021$)/(1000 MW) (right ticks) of each of the links from the prior slides. A separate figure for each ISO is presented that includes all links with at least one side of the link located within the ISO region. All relevant links are presented, so interregional links are presented in both regions associated with the link, for example, ERCOT<->SPP is equivalent to SPP<->ERCOT.

Links in SPP are calculated back to 2015 whereas links within other markets are calculated back to 2012. Three links in ERCOT are excluded from this figure, due to outliers in year 2018. These outliers are discussed in the next slide.

The CAISO region includes the non-ISO west which participate in the energy imbalance market.

Outlier values in ERCOT in 2018



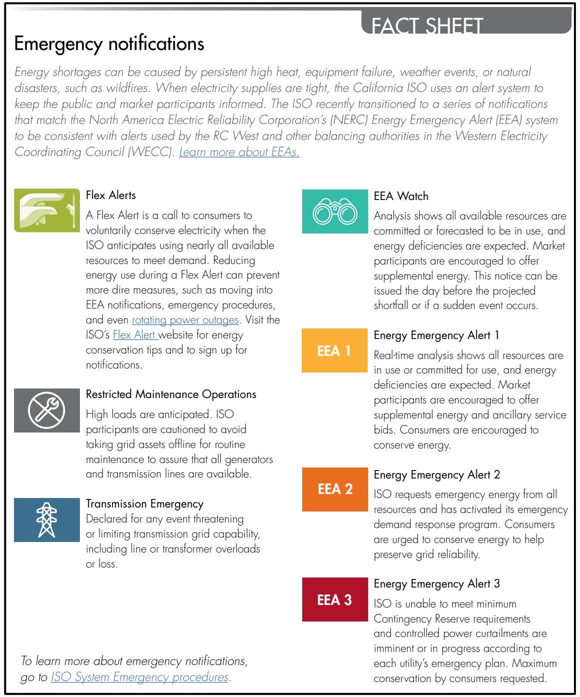


- Links to ERCOT Panhandle and Big Bend region spike in value in 2018 (and to a lesser extent in 2019).
- These values were excluded from the prior ERCOT specific time-series figures to allow trends in other links to be visible.
- These outliers show the possibility of transmission values that are even larger than those associated with the extreme winter weather in February 2021.

Analysis of Transmission Value During Extreme Events and High Value Hours

Analysis of the potential transmission value of mitigating congestion during extreme conditions

- Extreme conditions on the electricity system can be caused by a variety of factors.
  - Fluctuations in uncertain variables, either short-term or sustained (e.g. fuel price volatility, transmission and generation availability, inaccurate demand forecasts, inaccurate renewable forecasts).
  - Extreme weather events (e.g. heat wave / winter storm).
  - Exceptional levels of electricity demand (often correlated with extreme weather).
  - Infrastructure failures (in transmission or generation equipment, for example).
- Correlation of the above conditions can lead to particularly high system congestion.
- There is concern that modeling studies may not represent the value of extreme conditions observed in historical prices because modeling studies tend to focus on weather-normalized conditions with limited representation of uncertainty and equipment outage probabilities.
  - Partly because it can be difficult to incorporate such analysis accurately and comprehensively within one study and using available simulation tools.


FACT SHEET

Emergency notifications

Energy shortages can be caused by persistent high heat, equipment failure, weather events, or natural disasters, such as wildfires. When electricity supplies are tight, the California ISO uses an alert system to keep the public and market participants informed. The ISO recently transitioned to a series of notifications that match the North America Electric Reliability Corporation's (NERC) Energy Emergency Alert (EEA) system to be consistent with alerts used by the RC West and other balancing authorities in the Western Electricity Coordinating Council (WECC). Learn more about EEAs.

Flex Alerts

A Flex Alert is a call to consumers to voluntarily conserve electricity when the ISO anticipates using nearly all available resources to meet demand. Reducing energy use during a Flex Alert can prevent more dire measures, such as moving into EEA notifications, emergency procedures, and even rotating power outages. Visit the ISO's Flex Alert website for energy conservation tips and to sign up for notifications.

Restricted Maintenance Operations

High loads are anticipated. ISO participants are cautioned to avoid taking grid assets offline for routine maintenance to assure that all generators and transmission lines are available.

Transmission Emergency

Declared for any event threatening or limiting transmission grid capability, including line or transformer overloads or loss.

EEA Watch

Analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy. This notice can be issued the day before the projected shortfall or if a sudden event occurs.

EEA 1

Energy Emergency Alert 1

Real-time analysis shows all resources are in use or committed for use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy and ancillary service bids. Consumers are encouraged to conserve energy.

EEA 2

Energy Emergency Alert 2

ISO requests emergency energy from all resources and has activated its emergency demand response program. Consumers are urged to conserve energy to help preserve grid reliability.

EEA 3

Energy Emergency Alert 3

ISO is unable to meet minimum Contingency Reserve requirements and controlled power curtailments are imminent or in progress according to each utility's emergency plan. Maximum conservation by consumers requested.

To learn more about emergency notifications, go to ISO System Emergency procedures.

This example figure from CAISO identifies some of the issues that can lead to extreme grid conditions and cause emergency operational processes to be activated.
http://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf

Identifying extreme conditions: Two approaches

- Our goal is to find the portion of total transmission congestion value attributable to extreme conditions. To identify extreme conditions we use two approaches.
- In the first, we identify (through literature review and NERC reports) a list of specific events that are known to have impact the electricity grid. More information is included in the appendix.
- In the second we simply examine hours in which transmission value between two locations was in the top 10%, 5%, and 1% of all hours for that link. This second approach makes the assumption that, though there was not necessarily a named weather event or infrastructure outage during all these hours, the very fact that the price differential is so high indicates that an extreme condition exists. This extreme condition may not require emergency action by the ISO, but it is period in which the market faces extreme price differences.
- We note that the first and second approaches identify a somewhat overlapping set of hours, and we take care to prevent double counting when relevant.

Designated events

- Weather events identified in the literature: Named storms, heatwaves, polar vortex, etc.
- Periods of 'grid stress' identified in NERC reports

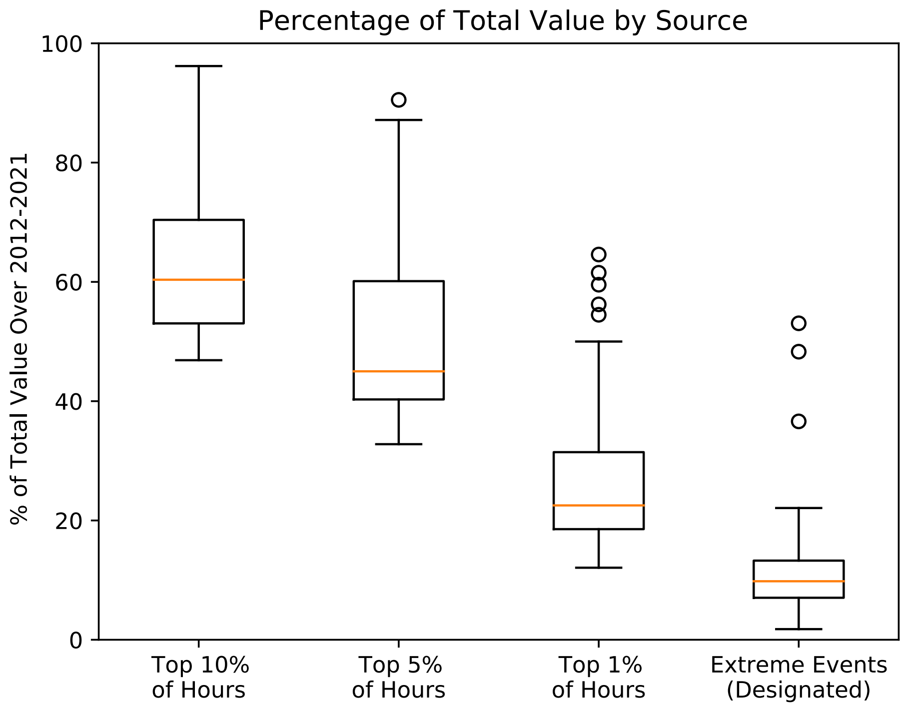
Top X%

- Hours identified by unusually large differences in prices between locations
- Specifically, the top 1%, 5%, 10% of price differences between locations over a specified time period.
- These hours may or may not overlap with the 'designated' events.

NERC: "North American Electric Reliability Corporation"

Extreme conditions and value

- In the median case, the top 10% and 5% of hours accounts for ~60% and ~50% of value, respectively.
- The top 1% of hours account of 20 to 30% of total value.
- Designated extreme events produce 10% to 20% of value (account for ~5% of total hours).
- This indicates that ‘extreme’ conditions that fall outside our extreme event designation process account for the majority of transmission value.

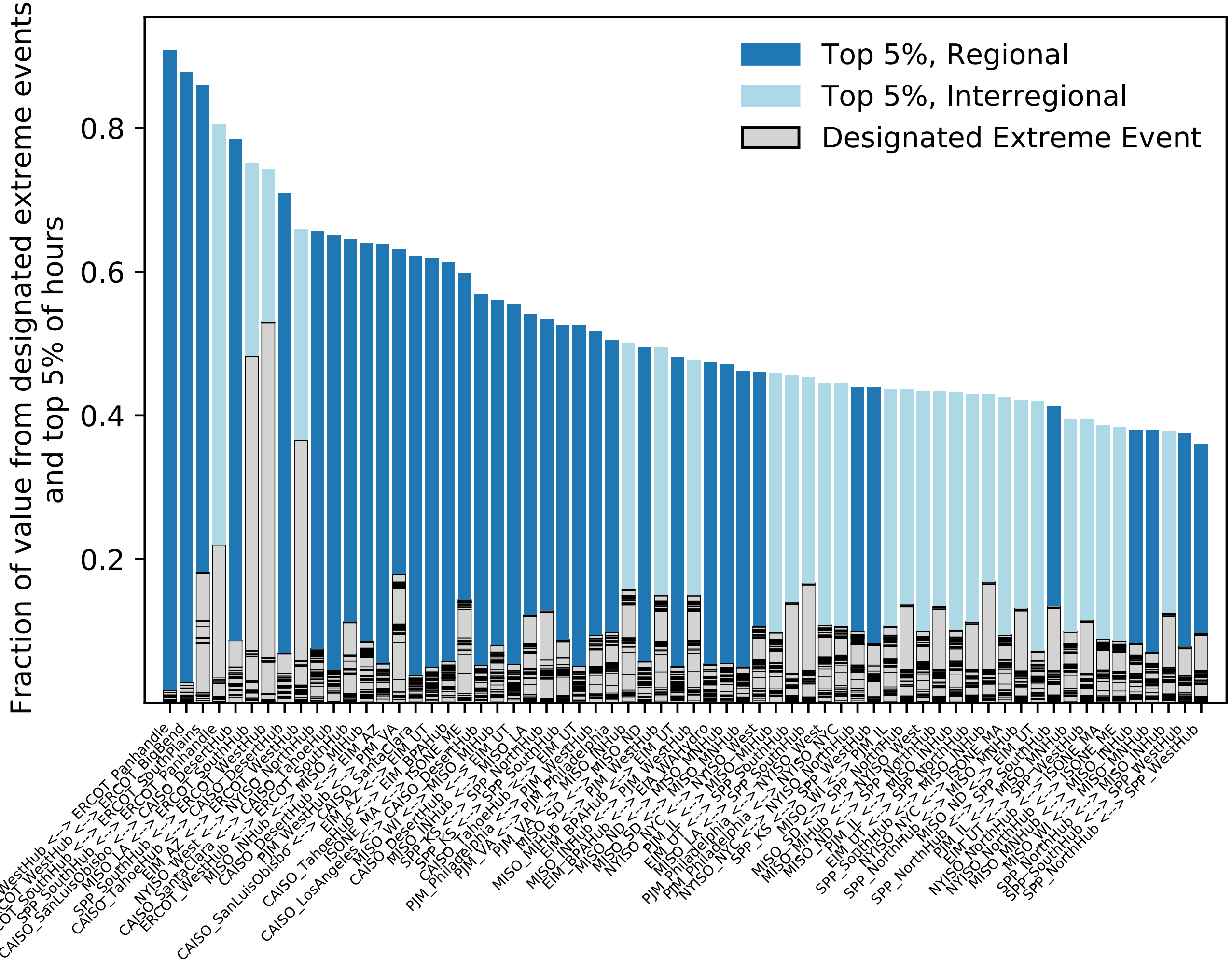


For each transmission link as established in the prior section, the total value over the study period was calculated, along with the value of the top 10%, 5%, and 1% of hours (in which these hours have been determined separately for each link).

Value was calculated for each link during all designated extreme events, even if the event occurred far from the link. Thus, the total value of designated extreme events is slightly larger than had we only accounted for locally relevant designated extreme events.

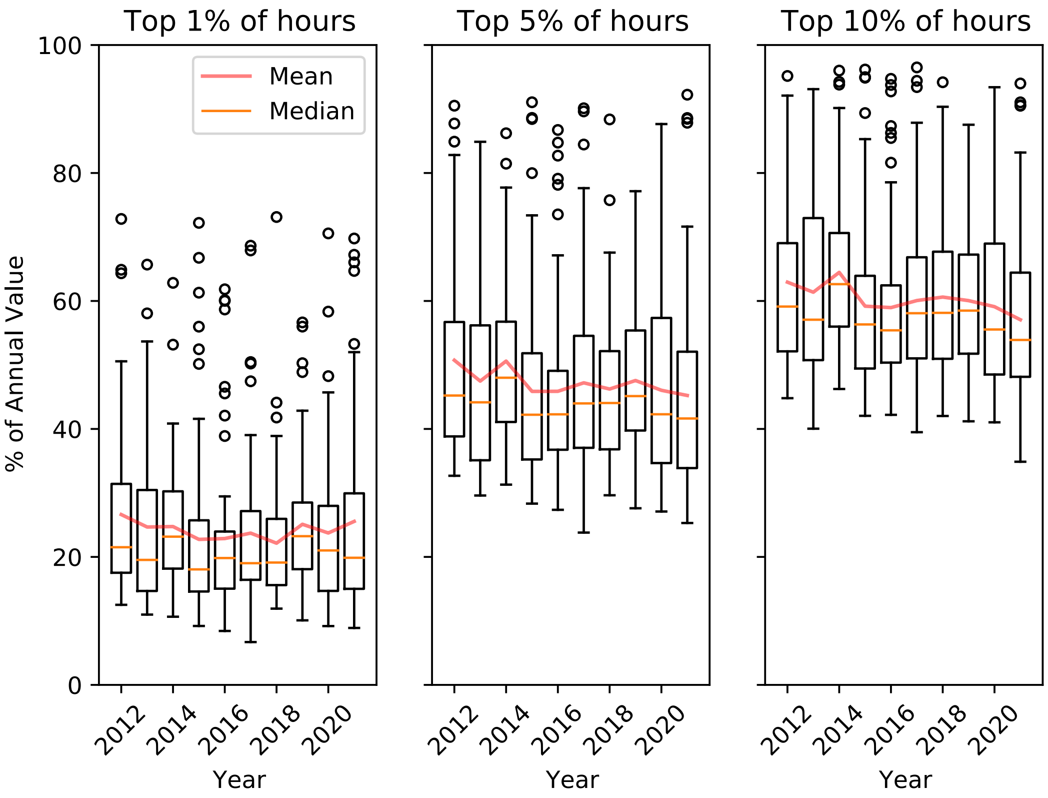
Value during extreme conditions, 2012 – 2021

- This figure shows the portion of transmission value attributable to either the top 5% of hours, or a designated extreme event.
- Hours are not double counted. If an hour is contained within a designated extreme event and is within the top 5% of hours, its value is only counted toward the designated extreme event.
- The value from each designated extreme event is shown as a separate box. In most cases, the event provides a small portion of total value and thus only the black outline is visible. In some cases, a large portion of gray fill indicates that a single designated event provides a substantial portion of total value over the study period.
- Extreme conditions, either designated or undesignated, account for at least 40% of transmission congestion value across all links.
- In most links, only one to three designated events provide a noticeable amount of value, with the rest of the events providing only a minor contribution.



Extreme conditions and high value hours over time

- There is high variability across the links – in each year there are some links in which even just the top 1% of hours accounts for greater than 50% of the value.
- The 10% of hours almost always accounts for at least 40% of value.



Can models realistically represent the complexity inherent in the values of transmission?

- Important context regarding transmission modeling: In recent years, there has been little deployment of interregional transmission. As discussed in the introduction, most transmission studies focus on a limited set of values (e.g., reliability) that can lead to a systematic undervaluation of transmission. A notable exception to this are the 'multi-value' transmission studies themselves.

- But, when transmission studies do estimate the direct value due to congestion reduction, are the models accurately representing that value?

- Of particular concern is when transmission studies use normalized weather profiles, are based on deterministic hourly simulations that do not account for uncertainty in load and generation, do not consider fuel price volatility, include only limited representation of infrastructure outages (e.g., do not explicitly model correlated outages across multiple generators or model outages of existing transmission lines), and do not represent other processes that contribute to the geographic price volatility observed in wholesale markets.
  - *Ref 1* (p. 36) details why common production cost models underrate transmission congestion value and production cost benefits.
  - *Ref 2* highlights that transmission value simulations that rely on deterministic hourly simulations that do not take into account uncertainty in real-time generation and load can underestimate transmission value by more than 2X (in some cases, up to 20X).
  - *Ref 3* (p. 67) indicates that common production cost models underestimate transmission congestion in the New York system by at least 40%.

- The above concerns are of particular importance given the empirical finding that 50% of transmission congestion relief value derives from only 5% of the hours – by not representing extreme weather or high value hours, modeled transmission value could be substantially underestimated.

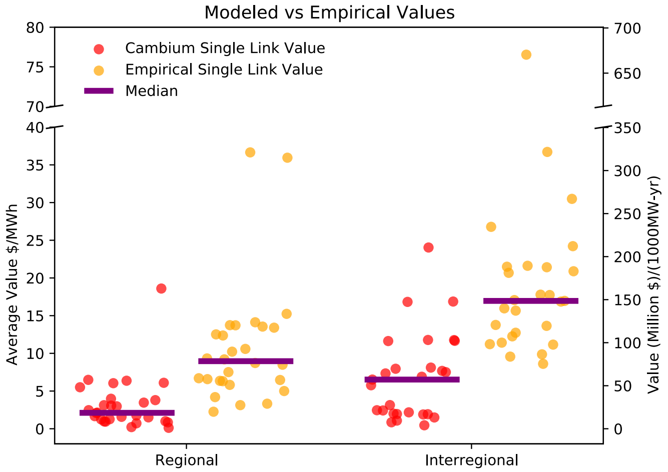
Ref 1. Pfeifenberger et al. (2021) "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs" The Brattle Group/Grid Strategies, https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/

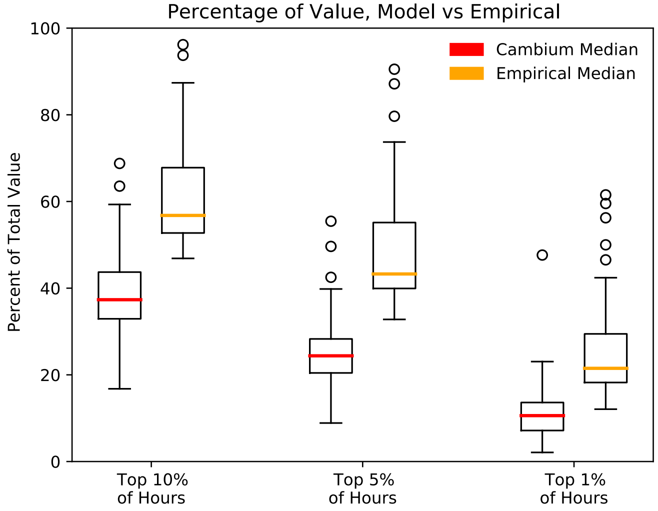
Ref 2. Horn et al. (2020) "The Value of Diversifying Uncertain Renewable Generation through the Transmission System" Boston University Institute for Sustainable Energy. https://hdl.handle.net/2144/41451

Ref 3. Pfeifenberger et al., (2021) "Initial Report on the New York Power Grid Study" NYSERDA, https://beta.documentcloud.org/documents/20463209-nypowergridstudy

Can models realistically represent the complexity inherent in the values of transmission?

- One example of underrating transmission value can be found in the Cambium-based national Standard Scenario modeling (*Ref 1*, and see the appendix for more details).
- It is important to note that this model is *not* used in a regulatory context to examine transmission value. Also, the modeling system has some explicit limitations in representing transmission value, including, but not limited to, a zonal rather than nodal market representation (though the zones are small enough to allow for representation of almost all the links included in the empirical analysis in prior slides).
- The point here is not to criticize a modeling system which was not intended to be optimized specifically for estimation of transmission value, but instead to demonstrate the consequences of not explicitly representing extreme conditions, extreme events, fuel-price volatility, generation and load uncertainty, and geographic market resolution.
- Comparing across the same set of links in the modeled and empirical analysis, the empirical transmission congestion value is almost 3X larger than the modeled value. This ratio was similar when looking at regional and interregional values. (see figure top right).
- This comparison is based on the average 2012 – 2021 empirical values versus a modeled year of 2022. As mentioned recent empirical values are even larger.
- One likely cause for this discrepancy in value is that a much smaller portion of total modeled value is due to extreme events or high value hours compared to the empirical analysis. For example, the top 5% of hours account for ~50% of value empirically, but only 25% in the modeled system (see figure bottom right).
- This comparison provides a demonstration that the concerns about modeling methodology listed in prior slides can indeed lead to a substantial underestimate of transmission value and also to modeling outcomes in which transmission value derives from fundamentally different mechanisms than in the empirical record (i.e., much less dependent on extreme events and high value hours).





1. Cole et al. (2021) “2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook” National Renewable Energy Laboratory (NREL). NREL/TP-6A40-80641. https://www.nrel.gov/docs/fy22osti/80641.pdf

Conclusions

Key conclusions

1. Wholesale power prices exhibit stark geographic differences that, in many cases, are stable over time.
2. Many regional and interregional transmission links have significant potential economic value from reducing congestion and expanding opportunities for trade.
3. The value of transmission is correlated with overall energy prices and varies by region and year. At many links, the transmission value in 2021 and the beginning of 2022 was substantially larger than the 2012 – 2020 average.
4. Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission's congestion value coming from only 5% of hours.
5. Transmission planners run the risk of understating the benefits of regional and interregional transmission if extreme conditions and high-value periods are not adequately considered.

Interpretation of transmission value

- **Avoided cost:** The congestion value of transmission calculated here is derived from the value of allowing a lower cost set of generators to meet load and by increasing operational flexibility through reduced congestion and increased interregional trade. Thus, value can also be thought of as the potential to reduce system cost through reducing congestion. In other words, properly accounting for the full suite of values that derive from transmission is critical toward building a least-cost electricity system.

- **Insurance value:** The fact that so few hours (5%) account for such a large portion of transmission value, and that a small number of extreme events (1 – 3 over ten years) can contribute meaningfully to the total 10-year value of a particular link, indicates that one lens with which to view transmission value is that of 'insurance' against the high costs of faced during extreme grid conditions, extreme events, or other factors (such as unexpected deviations from forecasted conditions).

- With insurance, as with some other benefits, attribution of value between different stakeholders is challenging because each stakeholder's potential benefits depend on the characteristics of future extreme grid conditions or weather events that are unpredictable. The attribution of this complex value is another challenge that faces transmission planners as they strive to weigh the costs and benefits of transmission expansion projects.

Key limitations

1. The transmission value analyzed only represents the value in reducing energy market congestion. It does not include value from capacity markets, reliability value, or other value streams described in the introduction.
2. The transmission value analyzed represents a marginal value and thus would be subject to saturation effects. We did not explore the capacity of transmission that could be installed at each location prior to substantial decline in marginal value.
3. Historical values do not necessarily reflect values under changing or future market conditions.
4. Some differences in pricing between regions is due to wheeling charges and differences in market rules and market structure rather than transmission constraints.
5. We did not investigate the costs of transmission, which vary greatly by location, distance, and many circumstantial factors.

Contact and acknowledgements

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More Information: https://emp.lbl.gov

Acknowledgements:
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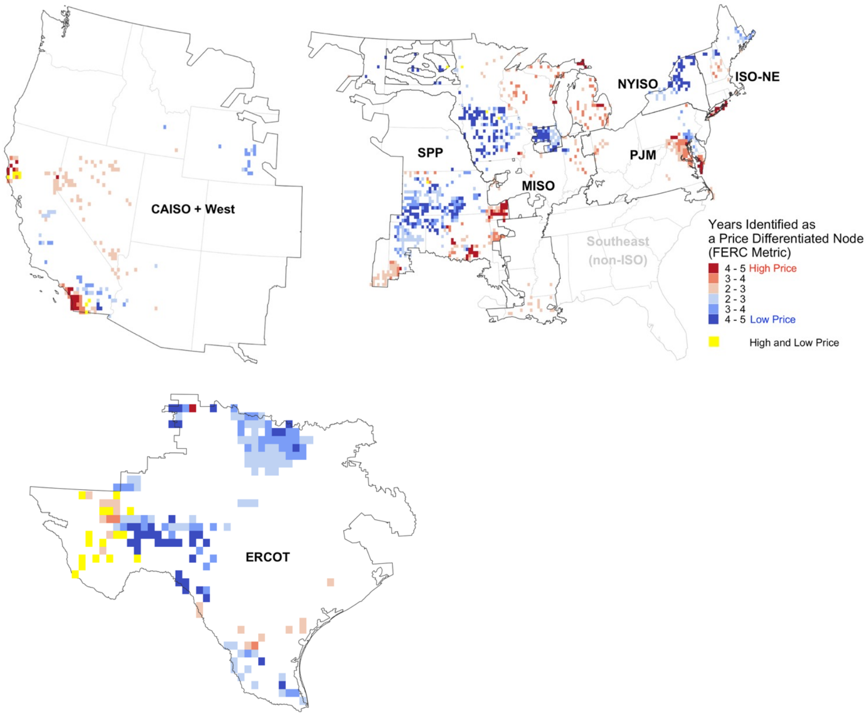
Appendix

Methods for the Market Price Differential Metric

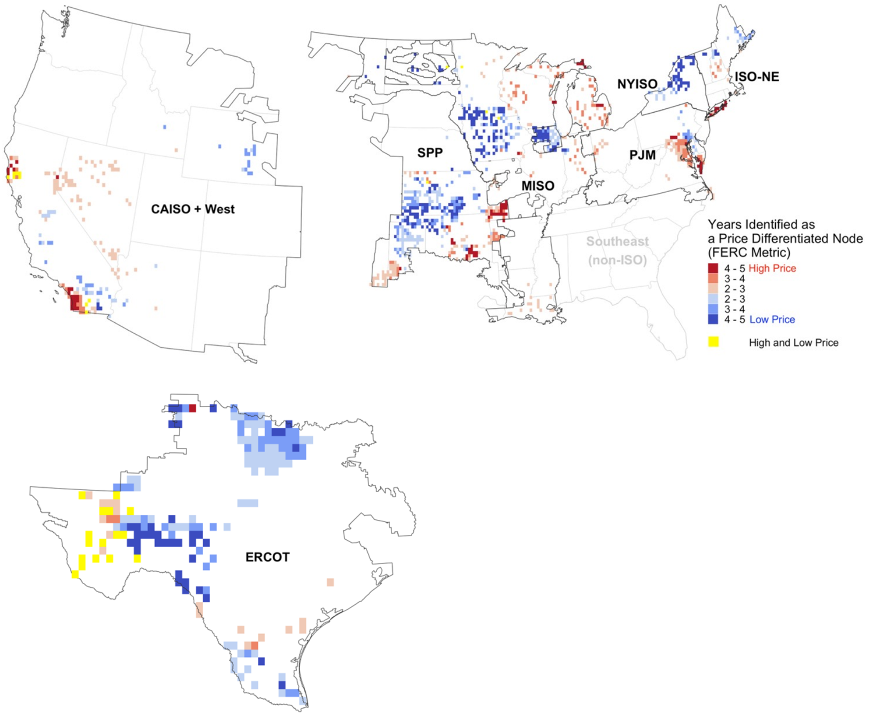


At each node, the 5th and 95th percentile price is calculated across all the hours in a particular year. Across all nodes in an ISO, the nodal 5th and 95th percentile values are averaged to find an average 5th and 95th percentile value for the ISO. Nodes are then identified as 'high-priced' if their 95th percentile price is greater than 1 standard deviation above the ISO average 95th percentile price. A node is identified as 'low-priced' if its 5th percentile value is less than 1 standard deviation below the ISO average 5th percentile value.

Each node is evaluated for each year from 2017 – 2021, and the number of times it is identified as high or low priced is summed over that time period. The results displayed in this Figure only include nodes if they have been identified as higher or lower priced for at least two years. Some nodes are identified as both high- and low-priced nodes. This metric is based on a similar metric of the same name developed by FERC (2016).

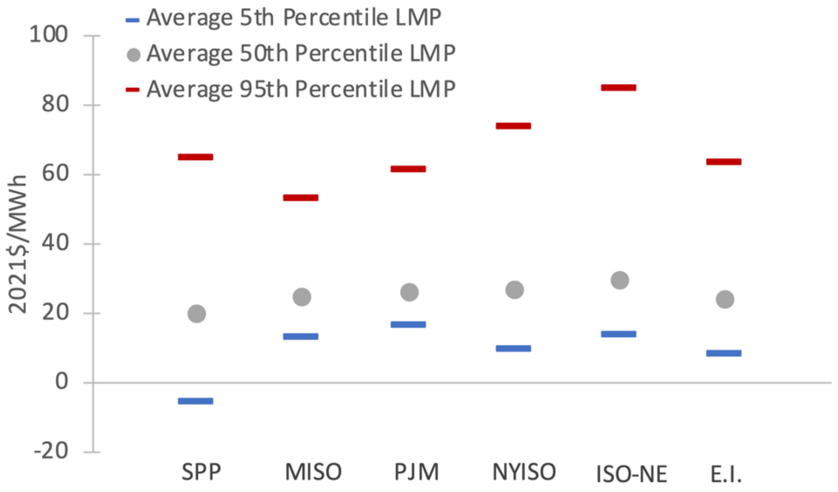
Federal Energy Regulatory Commission (FERC) (2016) "Transmission Metrics: Initial Results" AD15-12-000. https://www.ferc.gov/sites/default/files/2020-04/03-17-16-report_0.pdf

The Market Price Differential Metric: High- and low-priced regions identified within the wholesale markets of the Eastern Interconnect, the Western Interconnect, and ERCOT between 2017 – 2021.



	Eastern Interconnect	Western Interconnect	ERCOT
Low-priced regions	South and west KS OK / TX panhandles Southwest and central IA South MN Northeast IL Southeast PA Upstate NY North VT / NH	Mojave Desert CA East WY	North TX West TX South TX
High-priced regions	Southeast MO South OK Northwest WI East and UP MI Eastern MD / VA Delmarva Peninsula MD & DE Long Island NY	Southern coast CA Northern coast CA	

The Market Price Differential Metric: Additional context



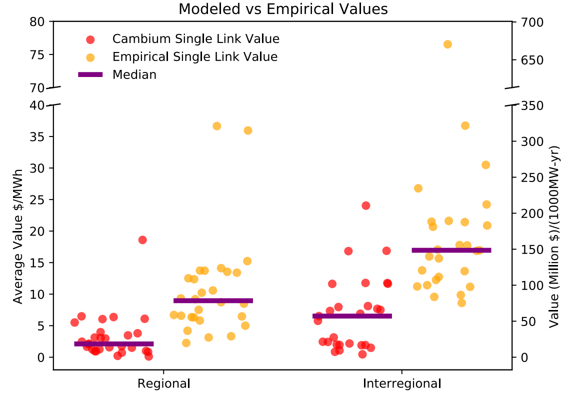
	SPP	MISO	PJM	NYISO	ISO-NE	E.I.
Average 5th Percentile LMP	-6 ± 10	13 ± 8	16 ± 3	9 ± 6	13 ± 5	8 ± 12
Average 50th Percentile LMP	20 ± 2	24 ± 2	26 ± 2	26 ± 4	29 ± 1	24 ± 4
Average 95th Percentile LMP	64 ± 14	52 ± 7	61 ± 1	74 ± 19	85 ± 3	63 ± 15

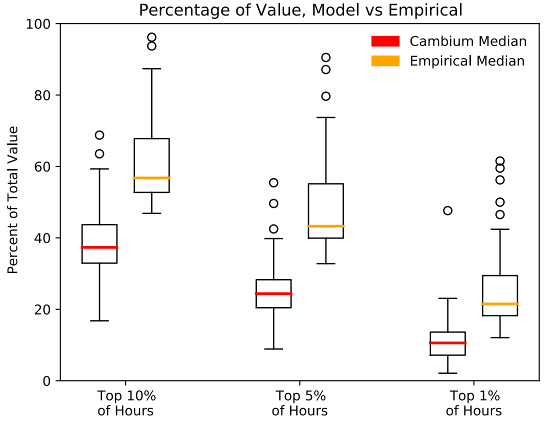
- The figure and table to the left show the median, 5th, and 95th percentile hourly prices, averaged across nodes within each ISO/RTO in the Eastern Interconnect, and also across the Eastern Interconnect as treated as a single region. Values shown represent the average of independently calculated values for each year from 2017 through 2021. Values in the table are mean ± standard deviation, in 2021$/MWh.
- This figure and table provides additional context about the Market Price Differential Metric by examining how prices vary across each ISO/RTO within the Eastern Interconnect.
- Average median prices are lowest in SPP at $20/MWh, highest in ISO-NE at $29/MWh, and the region-wide median is $24/MWh. 95th percentile prices range from $52/MWh to $85/MWh, and 5th percentile prices range from -$6/MWh to $16/MWh. Notable differences between the ISOs are the negative prices found in SPP, and the large standard deviation, relative to other ISOs, of the 5th percentile prices in SPP, and the 95th percentile prices in SPP and NYISO. High standard deviations in extreme prices across nodes indicate the existence of within-ISO congestion because it shows there is geographic spread in the patterns of high prices (high prices on their own do not necessarily represent congestion because it is possible they could be found at the same hours across the region, caused by issues other than congestion).

Identifying extreme conditions: Designated events

- We identified 171 extreme event days (with many events covering multiple consecutive days) between 2012 and 2021.
- We identified these extreme events based on specific events listed in:
  1. Goggin M. (2021) “Transmission Makes the Power System Resilient to Extreme Weather”, Grid Strategies. https://acore.org/transmission-makes-the-power-system-resilient-to-extreme-weather/#:~:text=The%20analysis%20finds%20that%20each,Uri%20in%20February%20of%202021
  2. Novacheck et al. (2021) “The Evolving Role of Extreme Weather Events in the US Power System with High Levels of Variable Renewable Energy” National Renewable Energy Lab. (NREL), NREL/TP-6A20-78394. https://doi.org/10.2172/1837959
- We also identified the top-10 NERC high grid stress days (using the severity risk index) as designated by NERC in their Annual State of Reliability reports. These can be found at https://www.nerc.com/pa/RAPA/PA/Pages/default.aspx
- These events covered various weather events, such as heatwaves, cold snaps, hurricanes, polar vortices, bomb cyclones, wind storms, winter storms, and other extreme weather events.
- The events also included non-weather related stressors, such as coincidental generator outages.

Methods for the comparison to modeled transmission value





- Here we examined the NREL Standard Scenarios which were created with a combination of the capacity-expansion model ReEDS and the dispatch model Plexos.
- We examined value in the model year 2022, using the 2021 model version, and specifically used the 'mid-case' scenario. See https://scenarioviewer.nrel.gov for more information.
- We matched model balancing areas to the empirical nodes and compared price time series between balancing areas to determine value in a similar manner to how value was determined in the empirical analysis. 9 of 64 links were not able to be recreated as both ends were contained within a single modeled BA. Of those 9, 4 were located in CAISO, 2 in NYISO, 2 in PJM, and one in ERCOT. All interregion links were replicated.
- We compared value to the average empirical value across 2012 – 2021. Empirical values were on average larger in 2021 and the beginning of 2022, meaning that the comparison to only recent data would show a larger discrepancy between modeled and empirical transmission value.
- Modeled average wholesale prices were similar to average empirical prices over the 2012 – 2021 period, though modeled prices were overall ~10% lower than observed prices. This difference in overall wholesale prices likely accounts for a small portion of the difference in modeled to empirical value of transmission. It would not account for the difference in the portion of transmission value contained in the top 5% of hours.