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Transmission value in 2023

Market data shows the value of transmission remained high in certain locations despite overall low wholesale electricity prices

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SUMMARY: In 2023 additional electricity transmission would have provided the most value for links that crossed between grid interconnection regions in the United States (the Western Interconnection, the Eastern Interconnection, the Texas Interconnection) or crossed between system operator regions within the same interconnection. Many multi-interconnection or multi-region links had values of greater than $20/MWh, or up to $175 million/yr per 1 GW expanded transmission (subject to limits to the depth of the market at each side of the link). In contrast, many links within regions, or between regions in the northeast, had relatively low values in 2023, following the overall decline in wholesale electricity prices in 2023 compared with 2021-2022. The most valuable link in 2023, at $61/MWh, was between Texas and the Southwest. Multiple events in 2023 (high natural gas prices in the western U.S., and high summer temperatures in Texas and the Southwest) were observed to have driven this high value. Of particular note, high prices in Texas occurred at a largely distinct set of hours from high prices in the Southwest, helping to drive up the value of transmission in total and demonstrating significant value to both regions. This example demonstrates the unique value of transmission (compared to other solutions, such as building local generation resources) in delivering benefits to multiple regions given its ability to connect areas of the country that inevitably face differing circumstances.

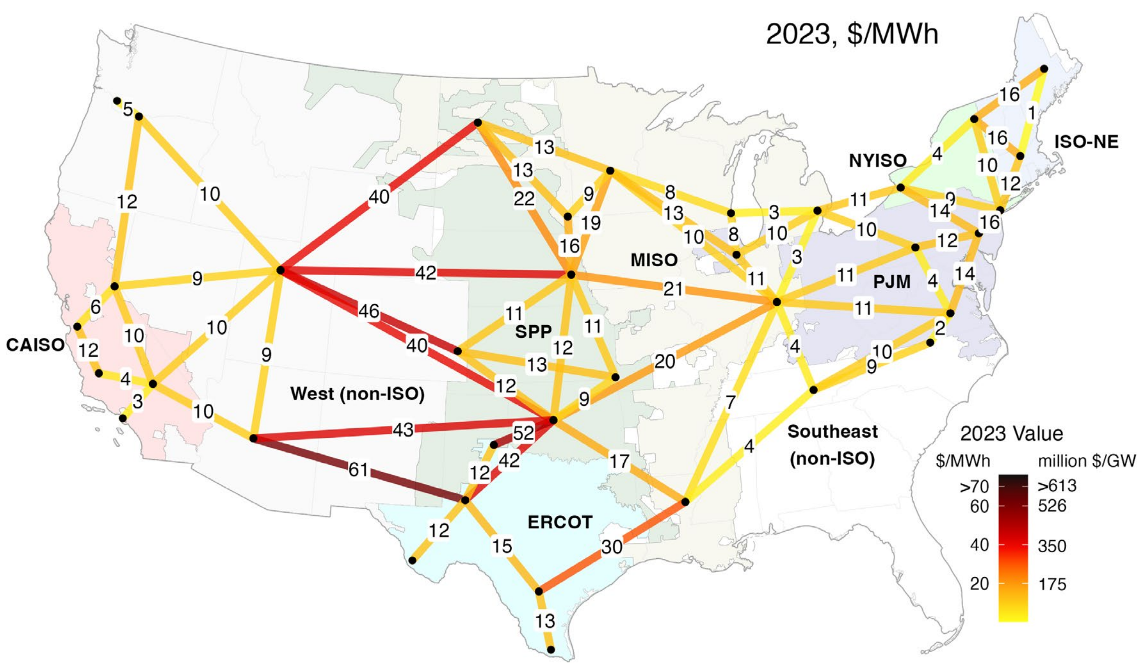

Figure 1. *2023 transmission value across a set of selected links. Transmission value was relatively high for links that cross between two of the three grid interconnection regions (the Western Interconnection includes CAISO and much of the Non-Iso West, the Texas Interconnection includes ERCOT, and the Eastern Interconnection includes the remaining regions shown). Also, a number of links that cross between different system operators within the same interconnection region saw relatively high transmission value. Note: at a GW of new transmission capacity, these values would likely be reduced by 10 – 30% due to market depth constraints as discussed in the text.*

Introduction

In this technical brief, we explore the potential value, or equivalently, the potential savings, that new transmission could have provided in 2023. The analysis differs from modeling approaches that are commonly used to value transmission, as it is based solely on the difference in wholesale-market energy prices between locations. In this brief when we refer to ‘transmission value’ we are referring to the value of additional transmission as indicated by locational price arbitrage (for example, in Figure 1). We do not calculate the value of existing transmission in this brief.

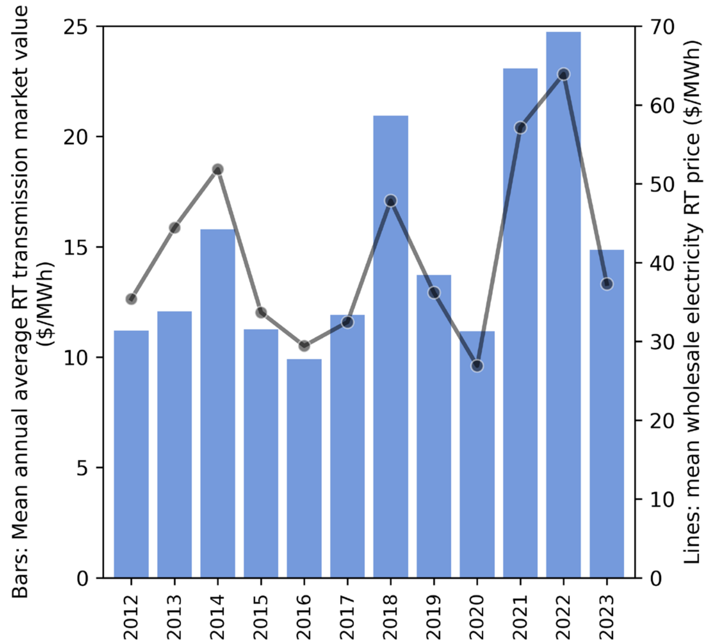

Figure 2. *Transmission value is highly correlated with overall energy prices, with 2023 transmission value (bars) following the decline in prices (line) observed last year. The average value shown is calculated across the set of links in Figure 1. Note that the set of links in the early years is smaller due to data constraints.*

Transmission can provide many benefits, including reducing locally high energy prices and increasing reliability and resiliency. While our approach captures the value of reducing locally or regionally high energy costs, it only partially reflects the value of reliability and resiliency (because energy prices alone do not fully capture the value of reliability and resiliency). Still the value analyzed here represents an important portion of the total value of transmission. The analysis of energy market prices provides complementary insight to analysis of transmission calculated with more typical electricity system modeling approaches. Such complementary insights can be useful for transmission planners and regulators. This is especially true given FERC’s recent issuance of Order No. 1920 requiring, in part, long-term evaluation of the benefits of proposed regional transmission projects, as well as broad continuing interest by FERC, NERC, DOE and others in inter-reginal transmission.

In prior research[1,2] focused on the period 2012-2022, we found that the potential savings of new electric transmission varied across years, was correlated with average wholesale-market energy prices (and thus natural gas costs), and was highest in 2021 and 2022. We found that extreme conditions and high-value periods have an outsized role in driving transmission value, though named extreme weather events oftentimes do not play as large a role as more-normal, but infrequent, conditions, such as infrastructure outages or demand forecast misses.

Now, with an additional year of data, we continue to explore how transmission value has evolved over time and discuss key factors that drove transmission value in 2023.

Related research from Berkeley Lab:

- Working paper on transmission value, including cost/value comparisons: Kemp et al (2024) "Electric transmission value and its drivers in United States power markets." https://doi.org/10.21203/rs.3.rs-3957695/v1
- Technical brief providing an update on transmission value in 2022: Millstein et al (2023). "The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade." https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf
- U.S. Department of Energy National Transmission Needs Study, which includes assessment of transmission value from Berkeley Lab and much additional analysis and context: https://www.energy.gov/gdo/national-transmission-needs-study

Notable trends in 2023

2023 average transmission value declined from past years along with the overall decline in wholesale electricity prices

Compared with 2022, 2023 saw steep declines in natural gas prices and thus wholesale electricity prices and transmission value. Figure 1 shows the average transmission value in 2023 for a set of selected links. Figure 2 shows the average transmission value over time across the set of links shown in Figure 1. As can be seen in Figure 2, average transmission value closely tracked the trend in average electricity prices from 2012 through 2023. Regions that saw the largest decline in transmission value from 2022 to 2023 include the northeast and mid-Atlantic, including the PJM, NYISO, and ISO-NE footprints. In 2022, most links with at least one side within these three regions had values between $20/MWh and $46/MWh. In contrast, most of these links had values close to $10/MWh in 2023, with $16/MWh being the highest value. Most of the decline in value was due to the decline in natural gas prices, which has the side effect of narrowing price differentials across regions with varying resource mixes. An additional factor was that transmission value in these regions in 2022 was elevated due to winter storm Elliott. Similar conditions that impacted wholesale markets were not observed in 2023, though other types of extreme weather events did occur.

Even these 'lower' transmission values in 2023 can be large in an absolute sense. For example, an annual average value of $16/MWh can provide substantial monetary benefits – if a transmission line with 1 GW of capacity were to receive the average value of $16/MWh each hour and was used at full capacity, the total value over a year would sum to $140 million (that is: $16/MWh * 8760 hours/year * 1000 MW/GW = $140 million/GW-yr). Note that the legend in Figure 1 shows transmission values as $/MWh and as million $/GW. There are two important caveats to that hypothetical total value per GW of new transmission. The first is that, if the transmission link had existed, it would have at least partially reduced the gap in prices between the two ends of the transmission line, meaning its total realized value for the year would be less than $140 million (as in the above example). How much less is a topic of current research, and for more information, see our working paper on this topic[1]; in general, the reduction is on the order of 10-30%. The second caveat is that transmission lines are often not used to their full capacity, sometimes due to physical restrictions (e.g., constraints related to high temperatures), and often due to challenges related to interregional coordination or contractual structures for energy exchange. This second caveat is also an area of ongoing research[3,4].

In 2023, as was the case in past years, transmission value was concentrated in a small portion of hours. Averaged across the set of links, 41% of total transmission value in 2023 derived from only 5% of the hours.

In fact, this concentration of value has been even higher in past years, for example, from 2012 – 2022, the top 5% of hours accounted for closer to 50% of the average transmission value[1]. That transmission value has been consistently concentrated in a relatively small number of hours across time shows that this characteristic is robust to the varying circumstances that occur across the different years. Thus, the ability to properly account for these high value periods is key to accurately assessing transmission value.

Despite the overall decline to transmission value in 2023, transmission value was higher than the long run average for links that cross between interconnection regions

Not all regions saw dramatic declines in transmission value in 2023. Transmission remained highly valuable for links that cross between interconnection regions. An interconnection region is a region in which the power grid is tied together and operated with the same synchronized frequency. In the contiguous United States, there are three main interconnection regions: the Western Interconnection (including CAISO and the non-ISO West), the Texas Interconnection (ERCOT), and the Eastern Interconnection (covering SPP, MISO, NYISO, ISO-NE, and the non-ISO southeast). Links that crossed these interconnection seams maintained high values through 2023. In the following section, we seek to offer insight into what drove the relatively high value for cross-interconnect links in 2023 by exploring why one example link was particularly valuable.

Events in 2023 demonstrate the unique value of electric transmission: the ability to alleviate high costs on either side of a transmission line

Transmission is one of several possible strategies to alleviate periods of high electricity costs. Other possible strategies include, but are not limited to, building new generation, building energy storage, increasing energy conservation, and expanding demand response programs. Each of these strategies has its own costs and unique set of benefits. Here we highlight a unique benefit of transmission that is enabled because, often, high prices in one region do not coincide with high prices in a neighboring region.

In early 2023, high natural gas prices were observed throughout the western United States. High prices were a result of unplanned maintenance in multiple gas pipelines, high heating demand due to a cold winter, and low natural gas storage in the west[5]. The high natural gas prices increased electricity prices throughout the west and thus raised the value of additional electricity imports into the region. For example, wholesale electricity prices were almost always higher in Arizona than in ERCOT during January through April of 2023, and the value of an additional GW of transmission between these regions summed to $190 million during the four-month period from January through April 2023. In this case, additional transmission capacity could have partially substituted for limits in the natural gas transmission system.

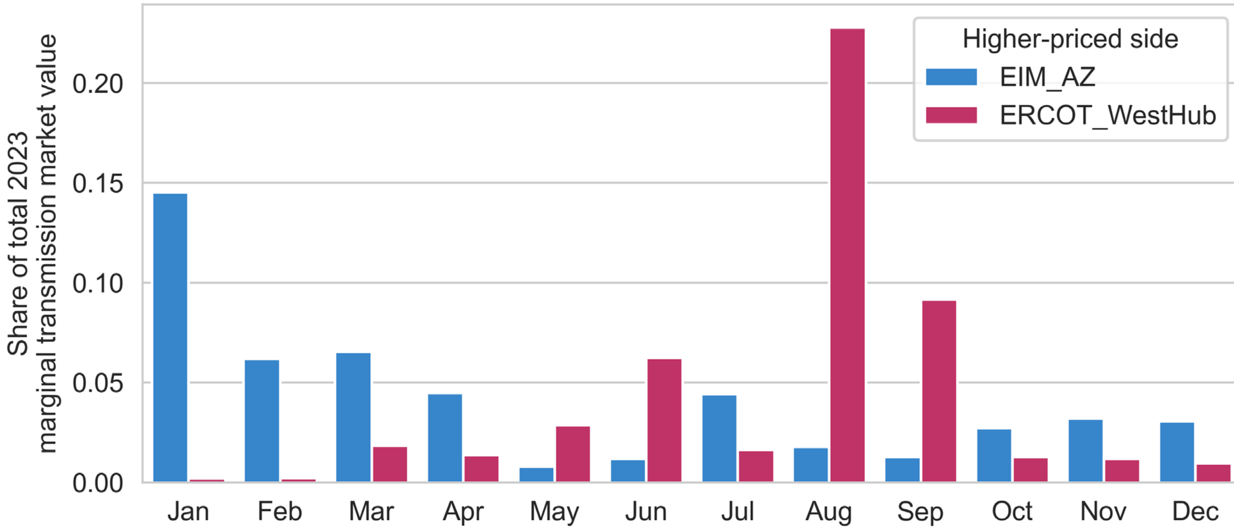

Figure 3. *Transmission value between a hub in western Texas (ERCOT) and a zonal market node in Arizona divided by month and by which location had the higher price in any particular hour. In the wintertime, high natural gas prices led to high electricity prices in the west (gas prices were high across the western U.S. but were low Texas) and this price difference drove high transmission values in the early portion of 2023. Extreme summer heat in both Texas and the Southwest affected electricity prices differently in each region and drove high transmission values in the late summer.*

In contrast, additional electricity imports into ERCOT would have been especially valuable during the extreme summer heat. The summer of 2023 was Texas's second hottest summer ever recorded[6], and ERCOT (the grid operator) had to request that residents reduce electricity usage during multiple August evenings to avoid straining the grid[7]. Summer electricity prices at the western hub node in ERCOT frequently spiked to hundreds, or occasionally thousands of dollars, during late afternoon and early evening. Meanwhile, in Arizona, August wholesale electricity prices were relatively low. Specifically, at a key zonal market node in Arizona, prices averaged $45/MWh in August, and prices only reached above $100/MWh for 15 hours in the month. In total, the value of an additional GW of transmission between these regions summed to $188 million during just the two months of August and September.

The differing winter and summer patterns in transmission value can be seen clearly in Figure 3, which shows the value of expanded transmission between ERCOT and Arizona by month and by which region has a higher hourly price in the real-time market. One detail to note in Figure 3 is that while most of the August transmission value derives from hours in which prices are higher in ERCOT, there is a small portion of value that comes from hours in which prices are higher in Arizona. In fact, Arizona also faced unusually high temperatures in August, but the exact timing of the heat as well as differences between each region's electric systems meant that the specific hours in August when the Arizona grid most valued electricity were different from those when the Texas grid most valued electricity. This difference in hourly timing can be seen in Figure 4, which shows, in the left panel, the top 50 priced hours in August in ERCOT-West and the associated prices in Arizona, and in the right panel, the same, but for the top 50 priced hours in August in Arizona. All top 50 price hours in ERCOT correspond to relatively low prices in Arizona (this is what drives the high transmission value for the month, as seen as the tall orange bar for August in Figure 3). But we also see that the highest prices in Arizona, at least those well above $100/MWh (this is the magnified area in the right panel of Figure 4), occurred at times when prices in ERCOT were relatively low for the month. The short blue bar for August in Figure 3 reflects the value of these high Arizona prices matching low ERCOT prices. This mismatch in timing of high prices demonstrates an example of a particular value of transmission – even neighboring regions facing the same large-scale heatwave may still have differences in the hours of peak energy need enabling transmission to reduce high prices in both regions.

The above discussion focuses on differences in pricing between Texas and Arizona, however pricing patterns were highly correlated across the southwest region. We analyzed a zonal node in Arizona because the electricity market in Arizona is much larger compared to the electricity market in New Mexico. However, the same patterns observed in Figure 4 are also seen when comparing Texas prices to a zonal node in New Mexico (see the appendix Figure A1). This shows that there is potential for highly valuable connections between ERCOT and both Arizona or New Mexico, with New Mexico having the advantage of relative proximity, and Arizona having the advantage of market size. Of course, one could imagine enhancing both the connection between ERCOT and New Mexico as well as enhancing the connections between New Mexico and Arizona, thereby addressing transmission to both locations, but that value and cost trade-off is not something we explore in this analysis.

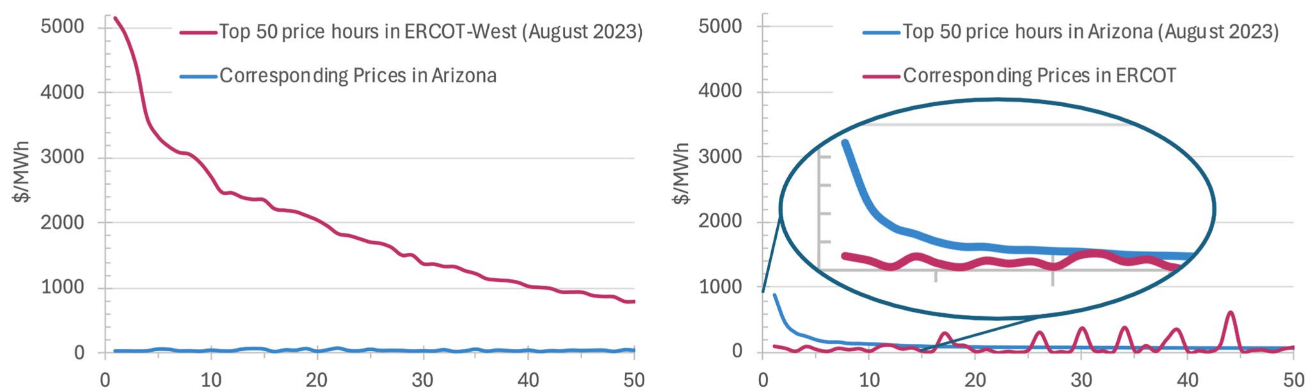

Figure 4. *While both Texas and the Arizona experienced extreme heat in the summer of 2023, differing circumstances in each region meant that the particular hours of peak electricity need (as indicated by prices) were different in each region – facilitating high transmission value. For example, in the left panel one can see that the top 50 price hours at the western hub node in ERCOT during August 2023 corresponded to relatively low-price hours in Arizona. Arizona prices in August averaged less than the 2023 annual average, but the small number of hours with prices above $100/MWh generally corresponded to low price hours in ERCOT (seen in the magnified portion of the right panel).*

Our transmission value update[2] covering 2022 also found important regional differences in timing associated with peak electricity demand periods, but in that case it was an example of a winter storm. Specifically, the update described the effects of Winter Storm Elliott on transmission value, finding that peak impacts on prices shifted from west to east on the scale of hours and days as the storm moved east. Similarly, outages to generation or other grid infrastructure can impact prices in one region for a period of hours or days, leading to somewhat random swings to which side of a transmission line would see relief from high prices caused by such an outage. Further discussion regarding the direction of energy flow across all the links shown in Figure 2, including discussion of how balanced that flow would be based on price signals, is included in our working paper[1].

Conclusions

Transmission value is impacted by overall average wholesale energy prices, as high average prices often also drive large price differentials. As prices were relatively low in 2023 compared to 2022, so was transmission value. However, for links where transmission bridged two interconnection regions, or in many cases, crossed system operator regions within an interconnection region, transmission value remained high in 2023. In this brief we investigated the causes for high transmission value between ERCOT and the western region of the U.S., finding that unique events (high regional natural gas prices in the west during the winter, and high temperatures in Texas and the Southwest in the summer) led to particularly large transmission values in 2023. Of note is that we showed how both regions could have benefited from the transmission link, as each faced high prices at different times. From a broader perspective, transmission value is often driven by idiosyncratic or unexpected events, and we have tracked other examples (such as winter storms), in past briefings. While winter storms and other extreme weather conditions provide dramatic demonstrations of transmission value, that value is often driven higher by more routine events such as infrastructure or power plant outages or missed forecasts of demand or generation. The drivers of transmission value are more systematically addressed in the citations included in this brief and will continue to be studied in ongoing research. As transmission planning typically involves value and cost comparisons, one important purpose of this line of research is to use market pricing data to gain insight into how to best assess transmission value for comparison with costs.

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Appendix

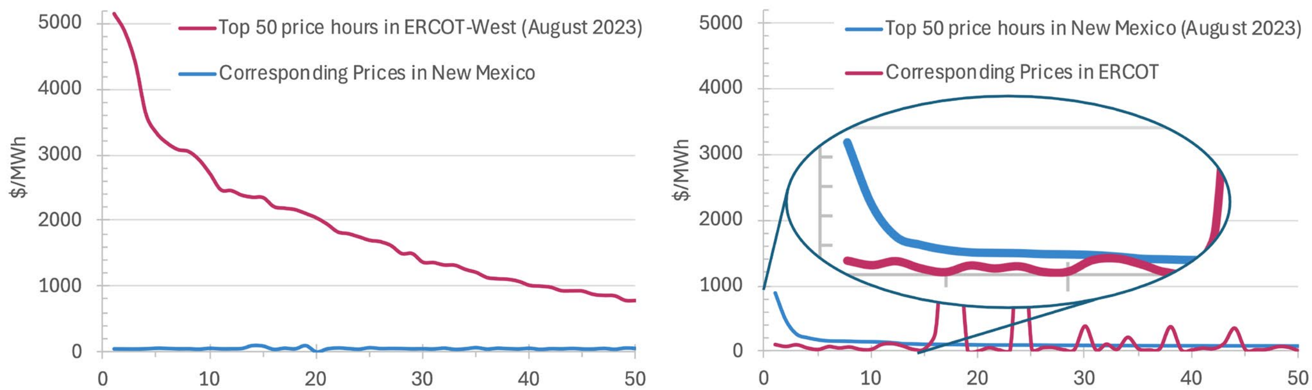

Figure A1. *The patterns seen in Figure 4 (which explored the lack of coincidence in peak prices between Texas and Arizona during the extreme heat in the summer of 2023), are also observed in this figure, which shows the same comparisons but swapping New Mexico for Arizona. In the left panel one can see that the top 50 price hours at the western hub node in ERCOT during August 2023 corresponded to relatively low-price hours in New Mexico. New Mexico prices in August were similar to those in Arizona, and the small number of hours with prices above $100/MWh generally corresponded to low price hours in ERCOT (seen in the magnified portion of the right panel).*

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