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THE EXPLOSION OF TRANSMISSION COSTS IN ERCOT:

Causes, Forecasts, and Policy Solutions

WRITTEN BY
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THE EXPLOSION OF TRANSMISSION COSTS IN ERCOT: CAUSES, FORECASTS, AND POLICY SOLUTIONS

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KEY POINTS

- **Transmission costs in ERCOT** rose from $1.5 billion in 2010 to over $5 billion in 2024 and could increase to over $12 billion per year by 2033.
- **After adjusting for inflation** and overall rising electricity demand, the average ratepayer in the ERCOT region paid 57% more in transmission charges in 2024 than in 2010.
- **Texas ratepayers are paying** about $1 billion per year to support transmission investments for wind and solar and have paid a total of nearly $15 billion since 2010.
- **If current transmission plans** are fully executed, the annual cost of transmission in ERCOT will more than double, adding at least $100 per year to the average residential ratepayer's electric bill.
- **Many new transmission** projects will primarily serve new data center demand, highlighting the urgent need to revise how transmission costs are allocated among all ratepayers.

EXECUTIVE SUMMARY

The transmission and distribution portion of the average residential ratepayer's bill in the Electric Reliability Council of Texas (ERCOT) region has grown from roughly 30% in 2002 to 40% in 2025 (Kavulla, 2025). Inflation in the electricity sector (BLS, 2024a) and rising demand have been two significant drivers of this increase, yet even after adjusting for those two factors, the average ERCOT ratepayer paid about 57% more in transmission charges in 2024 than in 2010.

Investments to support wind and solar generation have directly accounted for 28% of the total transmission cost of service (TCOS) passed through to ratepayers since 2013. The largest of such investments was the Competitive Renewable Energy Zones (CREZ) project, designed to connect wind and solar resources in West Texas to the cities in Central and East Texas. The capital cost of that project was $6.9 billion (Lasher, 2014, p. 8), and we estimate that its annual effect on TCOS—including operations and maintenance, taxes, depreciation, and financing costs—averaged over $750 million from 2014 to 2024. Additionally, the Public Utility Commission of Texas (PUC) estimates that the cost of interconnecting new wind and solar to the grid averaged over $300 million from 2020 to 2024 (PUC, 2023; PUC, 2024; PUC, 2025a).

While TCOS has been relatively stable over the last few years, several factors will cause costs to explode over the next decade. ERCOT forecasts that the total amount of new, repaired, and upgraded lines will increase 50% in 2025, 2026, and 2027 compared to 2022, 2023, and 2024, with investment totaling $14.9 billion, compared to $7.2 billion the prior three years (ERCOT, n.d.-a). Also, the PUC recently authorized three new 765-kV transmission lines, plus additional smaller lines, to meet growing demand from

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oil and gas operations and data centers in West Texas (PUC, 2025b). That investment is expected to cost nearly $14 billion when it is completed early next decade (ERCOT, 2025a, p. iii). When combined with ERCOT's proposal for more than $18 billion in 765-kV investments in the eastern half of the state, these high-voltage transmission projects could add more than $3 billion annually in TCOS charges to ratepayers.

As ERCOT dramatically expands the transmission system to primarily serve new industrial loads and relieve congestion caused by wind and solar generation, the cost/benefit equation for residential and small commercial consumers must be considered. Are there lower-cost alternatives to building large amounts of new high-voltage transmission with significant impacts on landowners and ratepayers? To what degree can market reform ensure the right kind of generation is built in the right places to minimize transmission buildout? Should new industrial consumers and generators pay for more of these new investments instead of socializing them evenly to all ratepayers? These questions must be asked by the PUC and by the Texas Legislature before new transmission investments are authorized.

INTRODUCTION: HOW TRANSMISSION AND DISTRIBUTION ARE PAID FOR IN ERCOT

The primary goal of electricity policy should be to provide all ratepayers with the most affordable and reliable electricity possible. This guiding philosophy is particularly important in the context of the transmission and distribution (T&D) system, which includes the wires and poles that deliver electricity from power plants to consumers. The T&D system in Texas is still operated by monopoly utilities with fixed service areas and regulated rates. Therefore, the cost of a utility's T&D investments is generally socialized across all consumers within its service area, and the cost of bulk transmission projects across multiple service areas is socialized across the entire system. How new investments are decided upon and how these costs are allocated are critical and challenging policy decisions that fall to the Public Utility Commission of Texas (PUC) and the grid operator, the Electric Reliability Council of Texas (ERCOT).

This paper will focus on the cost of transmission (the high-voltage lines that carry power over longer distances) and not on distribution (the low-voltage lines that carry power from substations to individual consumers). ERCOT allocates transmission costs using the Four Coincident Peaks (4CP) method, by which the transmission cost of service (TCOS) is allocated to distribution service providers (DSPs), based on the four highest 15-minute intervals in system-wide electricity demand during each of the summer months (i.e., June, July, August, and September). The DSPs then allocate their respective shares of transmission costs to their customers depending on rate class. The philosophy behind the 4CP method is that the bulk transmission system is built to serve peak demand, so a consumer's contribution to peak demand should determine their exposure to transmission costs.

One critique of the 4CP method is that it disproportionally benefits some consumers who can significantly curtail their peak demand and avoid almost all transmission charges. Notably, residential and small commercial customers are usually billed based on their total volume of consumption rather than their use during the critical peak periods, so their ability to affect their 4CP allocated cost is often limited. Industrial consumers, which usually offtake power at transmission voltages, have more freedom to reduce their

4CP exposure by reducing their peak demand, but many of them decline to do so because it would be prohibitively expensive or physically impossible to sharply reduce their demand for brief periods. About 20-30% of industrial consumers actively respond to energy and 4CP price signals and usually only do so with a portion of their load (Coleman et al., 2025, p. 2).

Since most consumers cannot meaningfully curtail their peak demand, the 4CP method is equitable for them. However, the increasing number of cryptocurrency miners and data centers in the ERCOT region that can curtail their loads—and have a strong incentive to do so under the 4CP system—means that cost allocation for these facilities must be carefully considered. This is why Senate Bill 6 in the 89th Texas Legislature required the PUC to reexamine the 4CP method (SB 6, 2025, pp. 12-13), which the agency has begun doing and will continue working on throughout 2026 (PUC, n.d.-a).

Unfortunately, transmission and distribution costs are becoming an increasing burden on Texas residents, and that portion of the average residential consumer's bill has risen from about 30% in 2002 to about 40% in 2025 (Kavulla, 2025). How to allocate transmission costs is an important policy decision, but because someone must pay for every pole and wire that goes up, the only way to minimize total costs is to build as little transmission as possible and to do so as cheaply as possible. Therefore, this paper focuses on the factors that lead to transmission being built, how much those upgrades and additions cost, and what should be done in the future to minimize the impact of transmission costs on all ratepayers.

As detailed in the next section, even after adjusting for inflation, the average ERCOT ratepayer paid about 57% more in TCOS in 2024 than in 2010. New projects being considered by the PUC and ERCOT could result in another 50% increase over the next decade. The primary causes of the increase in the last decade were projects built to serve new wind and solar generation. Having ratepayers pay for such investments directly—as the Texas Legislature chose to do in 2005 (Lasher, 2014, p. 8)—is a policy error that should not be repeated. However, the drivers of future transmission needs are more complex and will require more nuanced policy decisions.

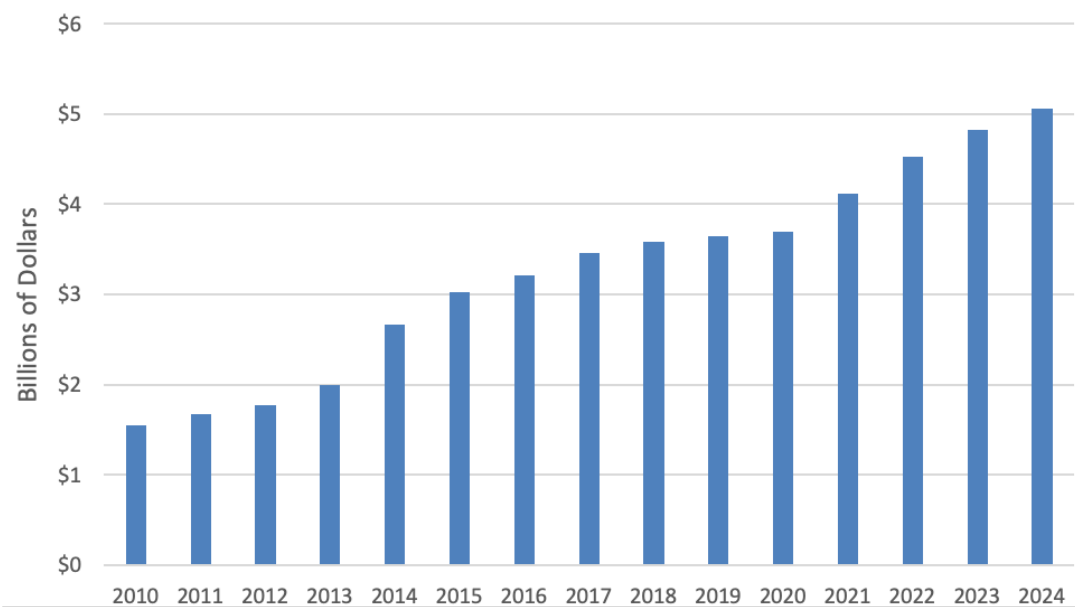
OVERVIEW OF TRANSMISSION COSTS IN ERCOT SINCE 2010

Every December, ERCOT publishes a document titled "Report on Existing and Potential Electric System Constraints and Needs" that summarizes transmission system improvements and costs over the past several years while projecting future planned projects and future needs (ERCOT, 2024a). The report draws from the wholesale transmission data that utilities are required to file each year with the PUC to estimate annual TCOS (PUC, n.d.-b). Compiling that data from 2010 to 2024 (*see* **Figure 1**) shows that annual TCOS in nominal dollars (not adjusted for inflation) rose from $1.5 billion in 2010 to $5.1 billion in 2024. The purpose of this section is to broadly explain the different factors that have caused this dramatic rise in costs, and the next section will take a deeper look at the impact on TCOS of investments to support wind and solar generation.

A primary driver of growing transmission costs is growing demand, and the true impact of TCOS on ratepayers can only be discerned by normalizing (i.e., dividing) TCOS by the total amount of electricity consumed (ERCOT, 2024a, p. 8). While TCOS more than tripled from 2010 to 2024, normalized TCOS only rose by 2.2 times (*see* **Figure 2**). Coincidentally, the average Texas household uses 1.1 MWh of electricity per month (EIA, 2025, p. 2), so **Figure 2** can be interpreted roughly as the monthly impact of TCOS on the average Texas ratepayer.

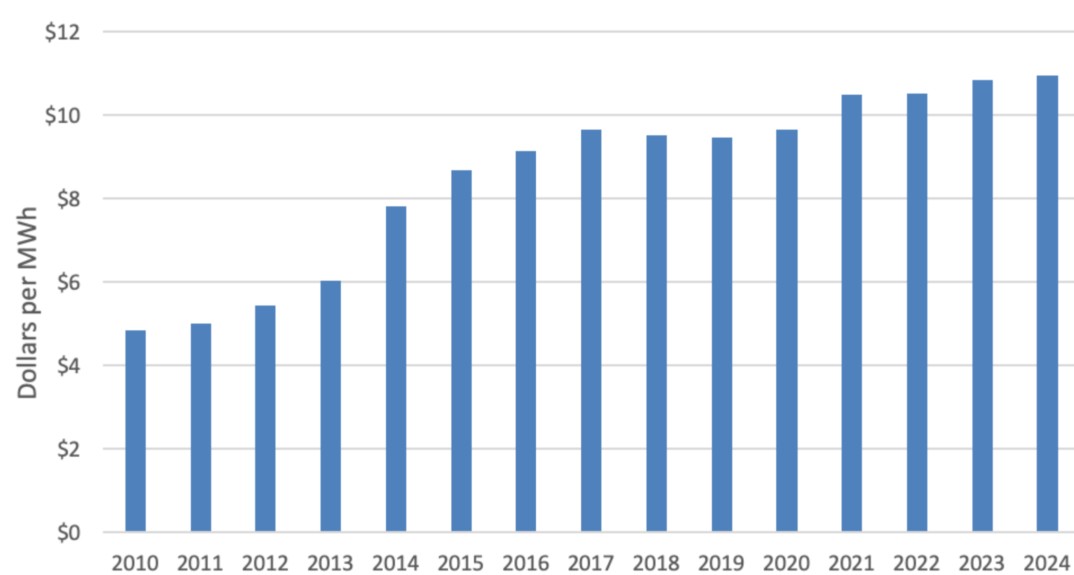
Normalized TCOS shows that three different trends in annual transmission costs have existed over the past decade. First, there is a dramatic increase from roughly 2012 to 2016. That increase was primarily caused by the Competitive Renewable Energy Zones (hereafter called the "CREZ lines"), which was a program created by the Texas Legislature in 2005

Figure 1
Annual Transmission Cost of Service in ERCOT, 2010-2024, Not Adjusted for Inflation



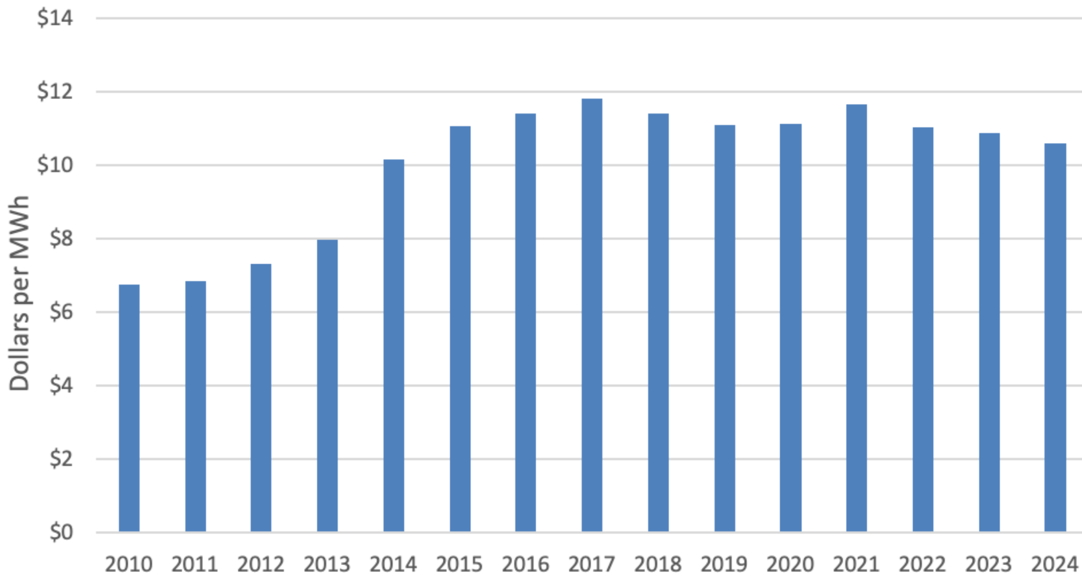
Note: Data from *Search Result: Utility Type = All, Filing Description contains "Wholesale Transmission Service Charges."* Public Utility Commission of Texas, n.d., retrieved October 18, 2025, from (https://interchange.puc.texas.gov/search/dockets/?UtilityType=A&ItemMatch=Equal&DocumentType=ALL&FilingDescription=Wholesale%20Transmission%20Service%20Charges&SortOrder=Ascending).

Figure 2
Transmission Cost of Service Per Unit of Energy Consumed, 2010-2024, Not Adjusted for Inflation



Note: Data derived by dividing the data in **Figure 1** by the total electricity consumed in ERCOT each year, which is taken from ERCOT's annual *Demand and Energy Report*, which can be found at *Helpful Resources*, Electric Reliability Council of Texas, n.d. (https://www.ercot.com/news/presentations).

Figure 3
Transmission Cost of Service Per Unit of Energy Consumed, 2010-2024, Adjusted to 2024 Dollars



Note: Data derived by dividing the data in Figure 2 by the consumer price index, which was taken from *Consumer Price Index for All Urban Consumers*: *All Items Less Food and Energy in U.S. City Average*, Federal Reserve Bank of St. Louis, n.d. (https://fred.stlouisfed.org/series/CPILFESL).

to connect wind and solar resources in West Texas to the cities in Central and East Texas (Lasher, 2014, p. 7). These lines, built at a cost of $6.9 billion from 2009 to 2014, are being paid off over 35 years, with a total uplift to TCOS of almost $20 billion over that time. A full explanation of how we estimated the impact of the CREZ lines on annual TCOS is provided in **Appendix A**.

Following that increase, normalized TCOS remained steady from about 2016 to 2020, then rose again from 2021 to 2024. The increase in recent years is almost entirely due to inflation, which has been particularly acute in the electric infrastructure sector. A simple inflation adjustment using the consumer price index (BLS, 2024b), which reflects how consumers view the cost of transmission charges relative to other goods they are purchasing, renders normalized TCOS roughly flat from 2015 to 2024 (*see* **Figure 3**).

However, even after the consumer inflation adjustment, the average ratepayer paid 57% more in TCOS in 2024 than they did in 2010. About half of this increase is likely due to a combination of inflation factors specific to the electricity sector and new projects to serve specific reliability and demand needs. The other half of this increase, amounting to over $1 billion in annual costs, can be attributed to the CREZ lines and to interconnection costs for new wind and solar generators.

COST OF TRANSMISSION AND INTERCONNECTIONS FOR NEW WIND AND SOLAR GENERATION

An important point to note about transmission investments is that the capital costs are just part of the total costs to consumers. These projects are typically financed over 30 years or more and must be maintained continuously, which is why the CREZ lines—with a capital cost of $6.9 billion—still cost Texas ratepayers

Table 1
Annual Transmission Cost of Service due to CREZ Lines and Wind and Solar Interconnections, 2010-2024

Year	CREZ	% of TCOS	Interconnections	% of TCOS	Total
2010	$0	0.00%	$204,209,054	13.23%	$204,209,054
2011	$0	0.00%	$219,899,345	13.17%	$219,899,345
2012	$0	0.00%	$236,209,756	13.33%	$236,209,756
2013	$268,428,130	13.41%	$253,176,224	12.65%	$521,604,354
2014	$626,332,303	23.55%	$270,836,336	10.18%	$897,168,638
2015	$872,564,329	28.89%	$289,229,414	9.57%	$1,161,793,743
2016	$850,395,825	26.44%	$308,396,609	9.59%	$1,158,792,434
2017	$828,255,474	23.97%	$328,380,991	9.50%	$1,156,636,465
2018	$806,143,837	22.49%	$349,227,656	9.74%	$1,155,371,493
2019	$784,061,490	21.54%	$370,983,826	10.19%	$1,155,045,316
2020	$762,009,017	20.64%	$401,084,303	10.86%	$1,163,093,321
2021	$739,987,018	17.97%	$427,179,584	10.37%	$1,167,166,602
2022	$717,996,100	15.85%	$455,549,400	10.05%	$1,173,545,501
2023	$696,036,887	14.42%	$475,329,318	9.84%	$1,171,366,205
2024	$674,110,011	13.34%	$484,162,639	9.58%	$1,158,272,649
Total	**$8,626,320,420**	**17.68%**	**$5,501,994,437**	**10.40%**	**$13,700,174,875**

Note: See **Appendix A** for the methodology and data sources for calculating the annual uplift to TCOS of the CREZ lines and **Appendix B** for the annual uplift to TCOS of new generation interconnections.

$674 million in 2024, more than a decade after the project was completed. Of that $674 million, about $210 million is for paying down the capital expenditure, $128 million is for debt financing, $200 million is for equity returns, $53 million is for taxes, and $86 million is for maintenance (*see* **Appendix A**).

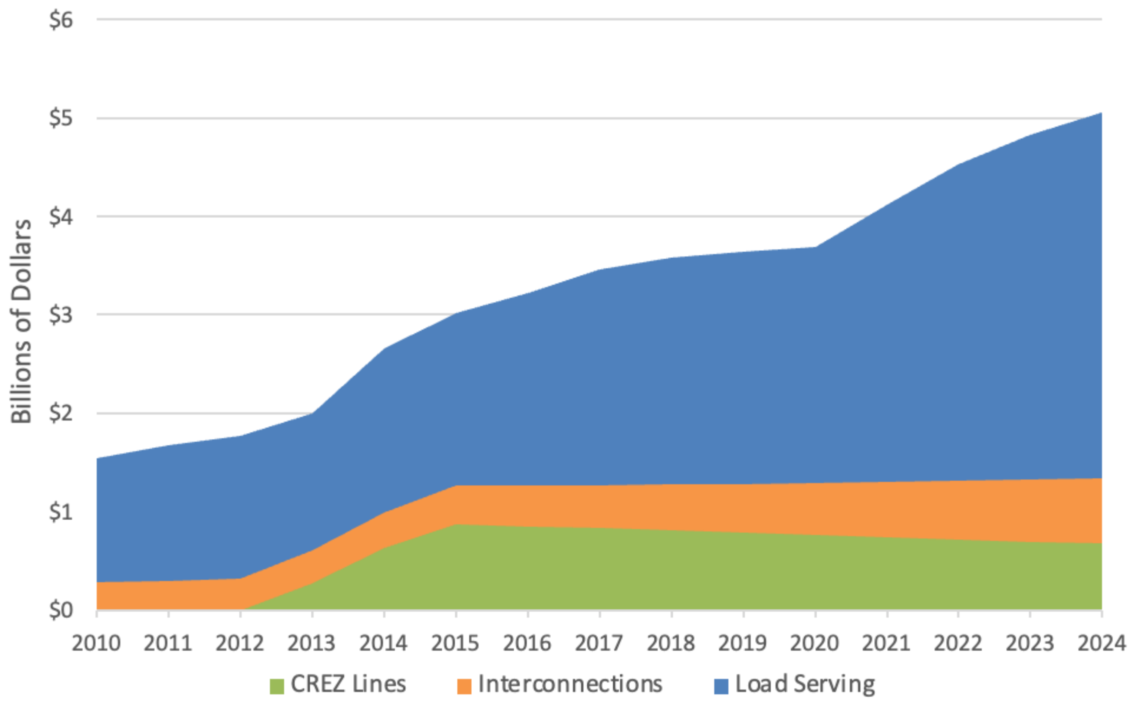
As shown in **Table 1**, the uplift to TCOS due to the CREZ lines in 2015 (the first full year after the lines were completed) was $870 million, or about 29% of total TCOS at the time. Since then, the CREZ uplift has declined to 13% of TCOS, while the uplift due to wind and solar interconnections[1] has grown from $289 million in 2015 to $484 million in 2024, holding steady at about 10% of TCOS. In aggregate, the annual uplift due to wind and solar has held steady at about $1.2 billion since 2015, and the total TCOS due to wind and solar from 2010 to 2024 was $14.7 billion.

Figure 4 shows these two cost categories (the CREZ lines and wind and solar interconnections) layered into the total TCOS. We assume the rest of TCOS is dedicated exclusively to load-serving transmission because there have been no major long-distance projects since the CREZ lines and very little new dispatchable generation. The figure makes it clear how the CREZ lines drove the increase in the middle of the 2010s, while the increase since 2020 was driven by other factors, primarily inflation in the electric power sector and a slight increase in the

1 Our estimate assumes interconnection costs are uplifted in the same manner as larger capital projects. Hard data on the capital cost of interconnections is limited to the 2020-2024 timeframe, so estimates for prior years are extrapolated from those 5 years of data. See **Appendix B** for details on our assumptions and calculations.

Figure 4

Annual Transmission Cost of Service due to CREZ Lines and Wind and Solar Interconnections, 2010-2024



Note: The data for the CREZ lines and interconnections is the same as in Table 4. The load serving portion is derived by subtracting the CREZ and interconnection costs from the total TCOS, which is derived from *Search Result: Utility Type = All, Filing Description contains "Wholesale Transmission Service Charges."* Public Utility Commission of Texas, n.d., retrieved October 18, 2025, from (https://interchange.puc.texas.gov/search/dockets/?UtilityType=A&ItemMatch=Equal&DocumentType=ALL&FilingDescription=Wholesale%20Transmission%20Service%20Charges&SortOrder=Ascending).

number of more expensive high-voltage lines being built (ERCOT, n.d.-a). Examining just the load-serving portion, the cost per MWh has doubled from about $4/MWh to $8/MWh, which is evidence that inefficiencies are manifesting in transmission building even apart from the wasteful use of transmission to serve wind and solar generation.

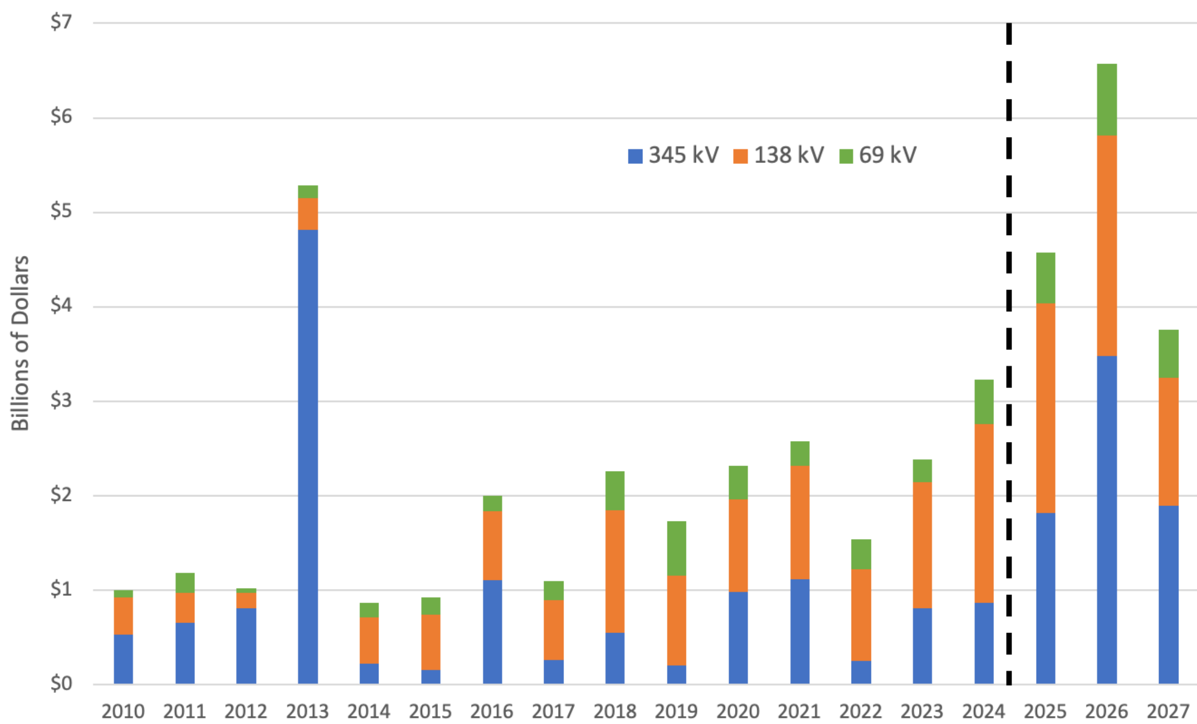
POTENTIAL IMPACT OF FUTURE TRANSMISSION INVESTMENTS

Unfortunately, the pressure on the transmission system in ERCOT is only going to grow in the next 5 to 10 years because of very high demand growth and a market design that continues to incentivize building variable wind and solar generation far from demand instead of dispatchable generation closer to demand. **Figure 5** demonstrates how ERCOT is forecasting transmission expenditures over the next 3 years to rise from an average of $2.4 billion per year from 2022 to 2024 to an average of $5.0 billion from 2025 to 2027 (ERCOT, n.d.-a). The bulk of the increase is driven by new 345-kV lines and upgrades to existing 345-kV lines, which indicates that most of the new money is for new customers in new regions (likely many data centers) rather than for rebuilding old lines that serve existing customers.

Making matters even more challenging, the cost increases in **Figure 5** will be quickly followed by $14 billion in new 765-kV lines and other upgrades recently authorized by the PUC (PUC, 2025b) to meet growing demand from oil and gas operations and data centers in West Texas. Combined with ERCOT's proposal for more than $18 billion in

Figure 5

Capital Cost of Completed Transmission Projects, 2010-2024, and Forecast Costs, 2025-2027



Note: Data from *Archived Transmission Project and Information Tracking*, Electric Reliability Council of Texas, n.d. (https://www.ercot.com/files/docs/2021/10/22/Archived-Transmission-Project-and-Information-Tracking.zip).

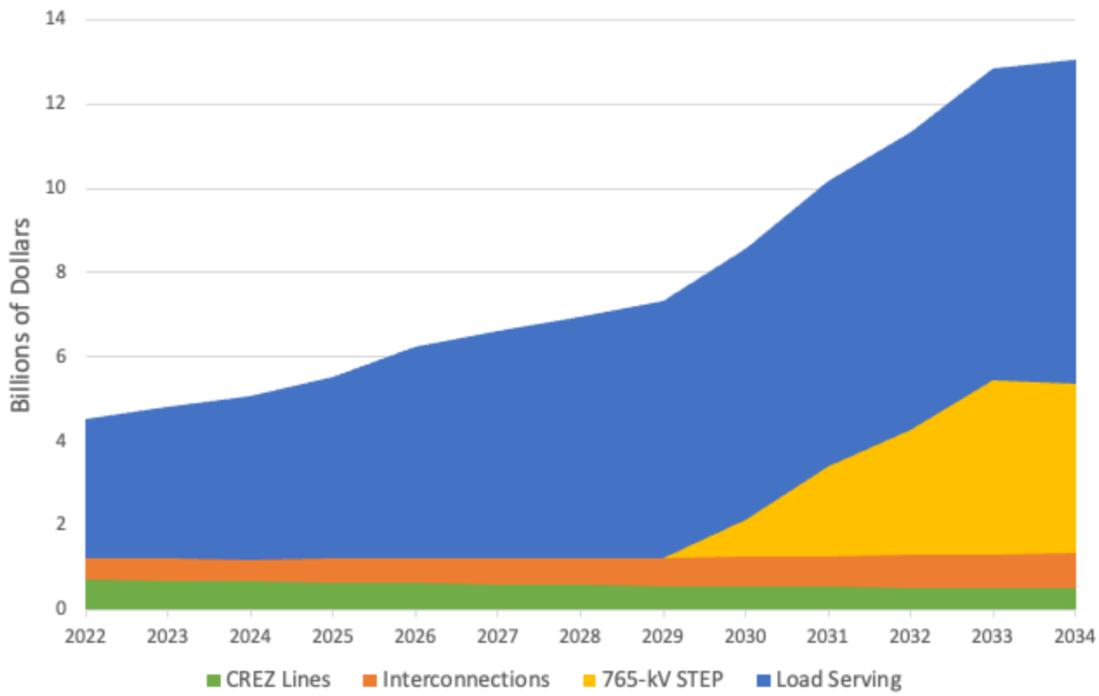
765-kV investments in the eastern half of the state (ERCOT, 2025a, p. iii), the combined investment in high-voltage transmission over the next decade will be nearly $33 billion—4.5 times the cost of the CREZ lines. If the new lines incur similar financing and maintenance costs as the CREZ lines, they will add more than $3 billion annually in TCOS charges to ratepayers across the 2030s (*see* **Figure 6**).

In all, we estimate that TCOS will increase from $5 billion in 2024 to $13 billion in 2034. Even if load growth averages 5% per year over the next decade, triple the average of the prior decade, the normalized cost will increase to $18/MWh. That increase translates to more than $100 per year for the average residential ratepayer, and some estimates place the increased burden at more than $200 per year per ratepayer (Kavulla, 2025, p. 5).

Furthermore, the ballooning cost of labor and equipment for transmission lines could escalate these costs even higher. The producer price index for the electric power and specialty transformer manufacturing sector rose 68% from 2020 to 2024 (BLS, 2024a), and the demand from data centers means that high voltage equipment prices will likely continue to rise for the rest of this decade. There is also historical precedent for ERCOT and TSPs underestimating the cost of these long-distance projects. The cost of the CREZ lines increased from about $4.9 billion when approved by the PUC in 2008 (PUC, 2008, p. 16) to $6.9 billion when they were finally completed in 2014 (Lasher, 2014, p. 8). It is almost certain that general inflation and changes necessitated by right-of-way acquisitions will increase the capital cost of the 765-kV lines above the initial estimates.

Figure 6

Annual Transmission Cost of Service due to CREZ Lines, Wind and Solar Interconnections, and New 765-kV Lines, Actual 2022-2024 and Estimated 2025-2034



Note: Data derived by combining the historical data from **Figures 4** and **5**, extrapolating those costs forward using the 2025-2027 average in **Figure 5**, and adding an estimated TCOS impact of the 765-kV STEP (using the same methodology as in **Appendix A**) based on a $33 billion capital cost and an initial uplift to TCOS beginning in 2030 and 2031.

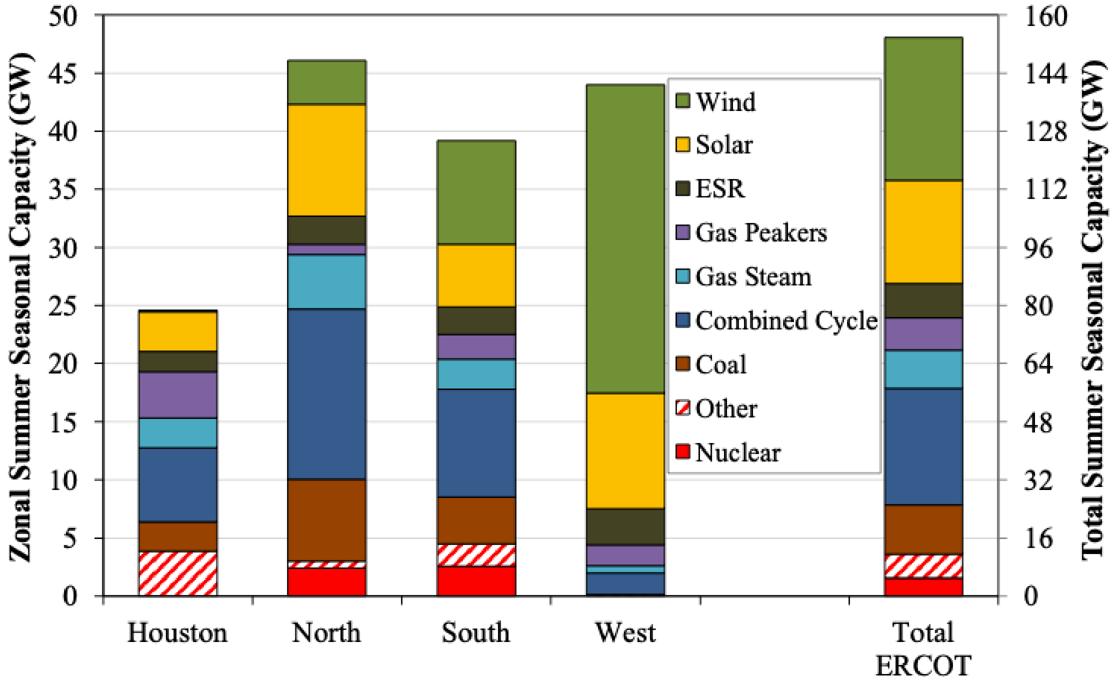
These long-distance transmission projects would be more palatable to Texas ratepayers if they were truly necessary, but these investments are simply a regulatory solution to a broken wholesale market and other factors that are incentivizing wind and solar generation in far-flung locations while making it impossible to build natural gas generation closer to new demand. **Figure 7** shows the degree to which generation types are geographically isolated in Texas. The Houston and North regions have most of the state's dispatchable capacity, but have limited ability to accommodate new generation due to environmental and geographic constraints. The South and the West are overloaded with wind and solar, which makes dispatchable power plants unprofitable in those areas. ERCOT and the PUC are therefore choosing to balance this system and accommodate demand growth by building long-distance transmission to connect these regions.

The Permian Basin import project is a perfect example of this problem. Demand in the Far West weather zone—which encompasses almost all of the Permian Basin that is experiencing rapid growth—is currently about 7 GW (ERCOT, n.d.-b). ERCOT's reliability study forecasts that Permian demand will explode to 23.7 GW by 2030 (ERCOT, 2024b, p. 8), and yet there is only 2.7 GW of gas generation capacity, 6.3 GW of wind, 6.1 GW of solar, and 2.3 GW of storage in the region right now (ERCOT, 2025b). Even with this forecast demand and some of the most abundant and cheap natural gas in the world, less than 7 GW of new gas generation is currently in the interconnection queue for the Far West zone. Of that 7 GW, only 2.2 GW is in the late planning stages with some certainty that it will be completed in the next few years (ERCOT, n.d.-d).

The gap between ERCOT's demand forecasts and the active and planned generation in the region is

Figure 7

Installed Capacity by Resource Type for Each Load Zone, 2024



Note: Figure from *2024 State of the Market Report for the ERCOT Electricity Markets*, Potomac Economics, May 2025, p. 17 (https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-State-of-the-Market-Report.pdf).

driving the "need" to import power to the region. Yet it is not clear from ERCOT's published reports where the excess power will come from. ERCOT's reliability study notes that the north-central weather zone, which is where two of the three lines will terminate, already has less conventional generation than peak demand (ERCOT, 2024b, p. 11). Data center demand will require new generation to be built in every part of the state. The bottom line is that ERCOT needs to do a better assessment of how much transmission would be needed if the right types of dispatchable generation were built in the right places.

Serious questions must also be asked about the demand projections ERCOT used in its study (*see* **Sidebar**), but the explosion of planned data center projects in West Texas means that the demand will likely materialize at some point, just not as quickly as ERCOT projects. But regardless of the demand forecasts, import lines would not be needed if sufficient dispatchable power were being built in the Permian Basin, which is not happening because the region is oversupplied with wind and solar most of the time, especially when counting wind and solar in neighboring regions that can export into the Permian (basically the entire West zone in **Figure 7**). Excess generation from wind and solar, which have a marginal operating cost that is virtually zero, suppresses prices below the operating cost of gas power plants during most hours, even if the gas is almost free.

In 2024, the average real-time price in the West load zone was $35.71/MWh (ERCOT, n.d.-c), which is well below the lowest quoted cost of a new combined cycle gas power plant ($48/MWh; Lazard, 2025, p. 8). Prices were below the lowest marginal cost of a fully paid-off combined cycle plant ($24/MWh) 55% of the time (Lazard, 2025, p. 13). Yet prices were above $100/MWh, indicating that demand is close to exceeding generation capacity, 5% of the time. Serving demand during the 5-10% of hours when existing resources (primarily wind and solar) cannot meet that demand is why the Permian Basin import lines are being built. The lines would not be necessary if there were generation available to fill those gaps.

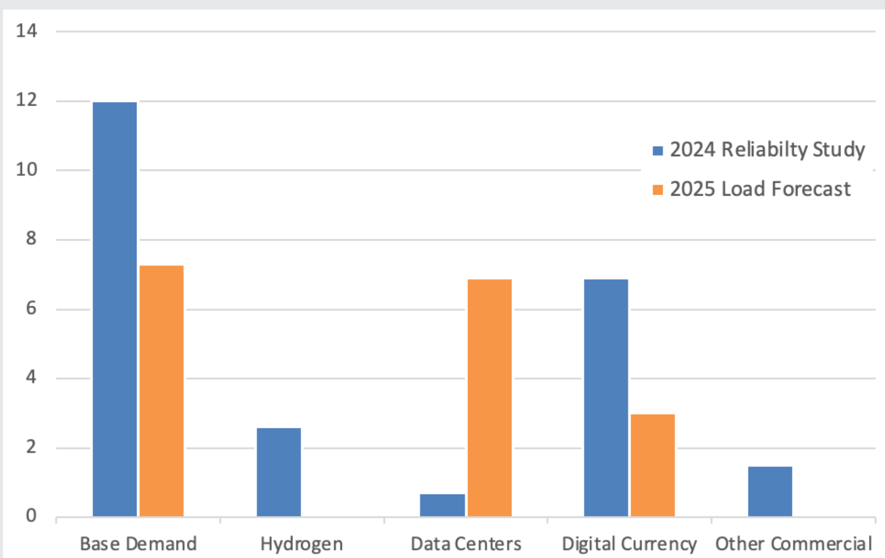
Sidebar: Uncertain Demand Projections Drive Aggressive Transmission Planning

ERCOT's Permian Basin Reliability Plan Study (ERCOT, 2024b) is an important example of how transmission planning depends upon demand forecasts and how those forecasts are becoming increasingly uncertain. The first source of expected demand growth in the Permian is the oil and gas sector, which is the primary political and legislative justification for expanding transmission there (HB 5066, 2023, p. 3). ERCOT relied on a single study from S&P Global (paid for by major oil and gas producers) that forecasts total grid load in the Permian increasing from 4.2 GW in 2022 (the study's base year) to 17.2 GW in 2032, of which 12 GW will be in the ERCOT region and the rest in New Mexico (p. 4). This 12 GW accounts for almost half of the 23.7 GW of demand for 2030 in ERCOT's reliability study (ERCOT, 2024b, p. 9).

The other 11.7 GW of the expected 2030 demand comes from digital currency mining (59%), hydrogen production (22%), data centers (6%), and other commercial/industrial loads (13%) (ERCOT, 2024b, p. 10). Only 39% of this demand was confirmed by signed contracts, with the majority of the remaining solely based on attestation letters filed with the transmission providers (p. 10). With the federal subsidies for hydrogen production now set to expire after 2027 (H.R. 1, 2025, Sec. 70511), most of the hydrogen demand is unlikely to materialize. Data center demand is rising considerably, and ERCOT's latest forecast shows these categories of loads contributing about 9.9 GW to the August 2030 peak demand in the Far West zone (ERCOT, n.d.-b). However, the 2025 forecast puts total peak demand at 17 GW in 2030 instead of the 23.7 GW in the 2024 reliability study.

ERCOT's current Permian load forecasts depend on highly uncertain computing loads, which are likely to be adjusted even more after the PUC adopts a new load forecasting formula in 2026 (Memorandum from Jessie Horn, 2025, p. 3). These changes need to be accounted for as the PUC goes through the formal routing process for the import lines over the coming year. If the original forecast is shown to be too aggressive, perhaps because of data centers bringing their own power or locating elsewhere, then the timing and sizing of the transmission builds should be adjusted accordingly.

Figure 8: *Comparison of ERCOT's 2024 Permian Basin Load Forecast and 2025 Far West Zone Load Forecast*



Note: Data from *ERCOT Permian Basin Reliability Plan Study* in Project No. 55718, Public Utility Commission of Texas, July 2024 (https://interchange.puc.texas.gov/Documents/55718_17_1414013.PDF) and *ERCOT Adjusted Forecast*, Electric Reliability Council of Texas, retrieved November 10, 2025, from (https://www.ercot.com/gridinfo/load/forecast). ERCOT's 2025 forecast does not break out hydrogen loads or other commercial loads, so all the large loads are classified under the data center category.

POLICY RECOMMENDATIONS

Unfortunately, Texas ratepayers are in a bind when it comes to the explosion of transmission and distribution costs in the ERCOT region. If Texas were to forgo future investments entirely, it would stifle economic opportunities in the oil and gas and computing sectors and increase the grid's vulnerability to outages. Conversely, allowing transmission and distribution charges to increase unabated will further harm already burdened low-income Texas ratepayers. The primary conclusion of this research is that Texas policymakers must use every available tool to mitigate the need to build new transmission while still accommodating the growth that the state desires. Secondly, policymakers should better align the cost of transmission with the entities that are benefiting from it, perhaps even creating a new rate tier for new industrial loads.

The first step is for policymakers to stop conflating local transmission upgrades to meet immediate demand growth with long-distance transmission projects based on highly uncertain demand forecasts. The Permian Basin reliability project is a good example of why these types of projects need to be separated. The local upgrades are required now to shorten interconnection backlogs in the region, and those upgrades were the primary motivation behind the legislation that initiated the project. However, the project has now been expanded—at a significant cost—to include long-distance lines that could be avoided if more dispatchable generation were built in West Texas. The two sets of upgrades were presented to the PUC as a single project, but they can and should be considered separately.

With that said, there are a few additional policy changes that must be made to ensure transmission costs do not increase any more than is required.

1. Finalizing the large load forecasting rule and acquiring load forecasts from ERCOT under the auspices of the new rule, including the impact of new controllable load resources that will not necessarily need new transmission in direct proportion to their peak load.
2. Finalizing the transmission cost allocation review and a full assessment of the costs of new transmission projects to all classes of ratepayers, especially the impact on residential rates, under the modified cost allocation regime.
3. An assessment of whether the need for long-distance transmission projects would be mitigated by further changes to the wholesale energy market.

These changes are all already underway and will be completed in the next 12 months. The PUC and ERCOT should not approve any further major transmission projects until these assessments are done, particularly the eastern portion of the 765-kV STEP.

Even after these changes are completed, the Legislature, the PUC, and ERCOT should apply lessons learned from the Permian Basin project to enable more careful assessment of new projects. While transmission is always needed to balance the system and deliver power, the need for so many long-distance lines is fundamentally driven by the failure of the wholesale market to properly incentivize the development of dispatchable generation close to load. The Commission and ERCOT should always first study alternatives to new transmission before approving new projects, unlike the approach recently taken, where ERCOT relied solely on a single, flawed projection of demand growth when approving additional import lines to the Permian Basin and did not even consider alternatives to new transmission lines.

The Commission and ERCOT also need to consider the impact of flexible loads and other methods to accommodate new data center demand within existing transmission and distribution infrastructure. Given that the 765-kV lines will not be in service until 2030 at the earliest, and market reforms to enable more dispatchable generation are also long-term processes, load flexibility is a more immediate solution to the explosion of growth that is expected over the next 3 to 4 years. Planning Guide Revision Request 134, which is currently pending review at ERCOT (ERCOT, n.d.-e), would make it easier for ERCOT to model controllable loads as consuming less than their maximum during peak hours, thereby reducing the amount of transmission needed to serve them. Reforms like this should be enacted expeditiously, and we suspect that if more of the data centers in ERCOT's transmission models were treated as flexible, the quantity of long-distance transmission would drop significantly.

Once it has been determined that new transmission projects are required, cost allocation for specific projects needs to be more carefully considered. While a single cost allocation methodology for the entire grid—be it 4CP or whatever new method comes from the PUC's assessment over the next year—is appropriate for spreading out the costs of smaller projects, it is not necessarily suitable for large single projects that provide concentrated benefits to relatively few stakeholders. While it is too late to reallocate the cost of the CREZ lines and other projects that fit this description, it is a perfect time to consider cost allocation of the projects in the 765-kV STEP and projects after it.

Finally, broader wholesale market reform is absolutely necessary to avoid the need for more transmission in the future. As Governor Abbott stated in a 2021 letter to the PUC, "Allocate reliability costs to generation resources that cannot guarantee their own availability," and "ensure that all power generators can provide a minimum amount of power at any given time" (Letter from Governor Abbott, 2021, p. 2). While the PUC is implementing a rule requiring variable generators to guarantee a certain amount of available capacity (PUC, n.d.-c), that rule will have limited impact given that it applies only to generation built after 2026. Unfortunately, the 89th Texas Legislature failed to broaden the policy to all generators (SB 715, 2025) and signaled that it is done with broader market reform. Such reform is badly needed to stop overpaying for unreliable wind and solar energy and to ensure that developers have the revenue certainty needed to build new, reliable generation close to new demand.

Electricity markets must be designed to serve all ratepayers, not just a subset of politically connected stakeholders. Unfortunately, Texas has traded the problem of regulating vertically integrated utilities for a toxic combination of regulators using monopoly transmission utilities to fix problems created by a broken wholesale market that is failing to produce the most affordable and reliable outcomes for Texas ratepayers. If Texas policymakers want to avoid sticking Texas ratepayers with ever-larger transmission bills, they must go back to the root of the problem and create a market that builds the right types of generation in the right places.■

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APPENDIX A: METHODOLOGY FOR CALCULATING THE ANNUAL TCOS OF NEW HIGH-VOLTAGE TRANSMISSION

The capital cost of transmission lines is just one piece of their total lifetime cost to the owner—the transmission utility—which passes those costs directly to ratepayers while also adding a fixed rate of return on the capital investment (in utility parlance, this is called "cost-plus" pricing). The lifetime cost is usually over twice the capital cost and includes the cost of financing, taxes, maintenance, and depreciation, as well as the utility's return on equity. These pieces are all calculated and added up every year, approved by the PUC, and passed onto consumers (through a process dubbed "uplifting") as the utility's TCOS.

To calculate the annual TCOS uplift for a given capital investment, the first step is to calculate the asset's depreciation, which is subtracted from the rate base against which the utility's debt and equity returns are calculated. As the asset is paid off over 33 years, the rate base drops from the initial capital cost down to zero, after which point ratepayers only need to pay maintenance costs. **Table A.1** shows how this calculation is done, using the example of the $6.9 billion CREZ project.

Table A.1
Capital cost, depreciation, and rate base for the CREZ lines in years 1 through 5 and in the final year (year 33)

Year	Capital Balance	Depreciation	Tax Depreciation	Deferred Depreciation	ADFIT	Rate Base
1	$6,900,000,000	$209,090,909	$460,000,000	$250,909,091	$52,690,909	$6,847,309,091
2	$6,690,909,091	$209,090,909	$460,000,000	$501,818,182	$105,381,818	$6,585,527,273
3	$6,481,818,182	$209,090,909	$460,000,000	$752,727,273	$158,072,727	$6,323,745,455
4	$6,272,727,273	$209,090,909	$460,000,000	$1,003,636,364	$210,763,636	$6,061,963,636
5	$6,063,636,364	$209,090,909	$460,000,000	$1,254,545,455	$263,454,545	$5,800,181,818
…	…	…	…	…	…	…
33	$209,090,909	$209,090,909	$0	$0	$0	$209,090,909

Note: The ADFIT is calculated assuming a fixed federal corporate income tax rate of 21%, applied to the deferred depreciation balance.

By law, utilities depreciate transmission assets over 33 years (*see column 3 in* **Table A.1**), and the capital balance on the asset (*see column 2*) declines by this fixed amount every year. However, the taxable value of the asset depreciates over 15 years (*see column 4*), which creates accumulated deferred depreciation (*see column 5*). This accelerated depreciation creates an accumulated deferred federal income tax (ADFIT) balance (*see column 6*) that is then subtracted from the capital balance to determine the rate base (*see column 7*). The effect of these accounting gymnastics is to reduce the annual return on equity—which is 10.5% of the asset's rate base each year—and to reduce the taxes paid on the annual equity earnings.

Figure A.2 shows how the annual TCOS is calculated from the rate base. In all the cases where this calculation is used in this paper, we assume the annual return on equity is fixed at 10.5% of the rate base, the interest rate (return on debt) is fixed at 5.5%, and the tax rate (applied to the annual equity return) is 21%. We also assume the project is financed with 45% equity and 55% debt. Maintenance and operations costs are assumed to be 10% of the initial capital cost and are increased by 2% every year to account for inflation. The annual TCOS is the sum of the equity return, debt return, taxes, and maintenance costs, plus the amount of annual depreciation (*see column 3 in* **Figure A.1**).

Table A.2
Components of the annual cost of transmission for the CREZ lines in years 1 through 5 and in the final year (year 33)

Year	Rate Base	Equity Return	Debt Return	Taxes	Maintenance	Annual TCOS
1	$6,847,309,091	$323,535,355	$207,131,100	$86,003,069	$69,000,000	$894,760,433
2	$6,585,527,273	$311,166,164	$199,212,200	$82,715,056	$70,380,000	$872,564,329
3	$6,323,745,455	$298,796,973	$191,293,300	$79,427,043	$71,787,600	$850,395,825
4	$6,061,963,636	$286,427,782	$183,374,400	$76,139,031	$73,223,352	$828,255,474
5	$5,800,181,818	$274,058,591	$175,455,500	$72,851,018	$74,687,819	$806,143,837
…	…	…	…	…	…	…
33	$209,090,909	$9,879,545	$6,325,000	$2,626,208	$130,033,301	$357,954,964

APPENDIX B: METHODOLOGY FOR CALCULATING THE ANNUAL TCOS OF INTERCONNECTING NEW GENERATION

The annual TCOS of interconnecting new generation is calculated using the same method as in **Appendix A**, applied to the capital cost of new interconnections each year. The process is challenged by the fact that the PUC and ERCOT only have public data for the cost of interconnections available for the years 2020-2022 (PUC, 2023), 2023 (PUC, 2024), and 2024 (PUC, 2025a). Therefore, we need to make some assumptions to extrapolate that data back to 2010 and forward to 2034.

From 2010 to 2020, we assume the capital cost of interconnections grew at an annual rate of 5%, increasing from $174 million to $284 million over that time. This rate of growth is assumed to resume in 2025 and remain consistent through 2034. While the amount of new generation added over the coming years is anticipated to be larger than even what the ERCOT region has experienced over the past several years (ERCOT, 2025b), we assume that a larger proportion of that generation will come from gas due to declining federal subsidies for wind and solar. To calculate the annual TCOS, we begin with a value of $200 million (the accumulated TCOS of assets added prior to 2010) and add the annual TCOS of the assets added each year. While the TCOS of each vintage of assets declines by about 3% annually, the addition of new assets every year causes the total annual TCOS due to interconnections to rise over time, reaching $842 million by 2034.

Prior to 2020 and in 2025, the cost of wind and solar interconnections is fixed at 90% of the total annual interconnection cost, which is equal to the average proportion from 2020 to 2024. From 2026 onward, the proportion of interconnection costs due to wind and solar declines at a rate of 10% annually, again based on the assumption that declining federal subsidies will reduce the proportion of wind and solar being interconnected relative to new gas generation. Therefore, annual wind and solar interconnection costs peak in 2022 at $317 million and fall to $138 million by 2034. Despite the declining investment each year, the annual TCOS of wind and solar interconnections continues to rise, from $513 million in 2025 to $559 million in 2034, because the uplifted costs of the investments are spread out over 33 years.

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