High Voltage, High Rewards Transmission: Appendix C

Technical Appendix

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February 2025

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Appendix C: Overview of Benefit-Cost Analysis

Appendix C provides more details on the methodologies, inputs, and limitations of the analyses. As described in the body of the report, the goal of the analysis is to quantify the benefits and costs of transmission projects, focusing on three core benefits — congestion relief savings, resource adequacy savings, and public policy savings.

Transmission Carrying Capacity

Traditionally, determining transmission carrying capacity involves power flow simulations that account for complex factors, such as line impedance, voltage constraints, dynamic stability, and system-wide interactions.

However, our analysis evaluates transmission lines in isolation to directly assess their associated benefits and costs. For alternating current lines, we do this by estimating their incremental power-carrying capabilities based on mileage and voltage — the physical characteristics most directly influencing a line's capacity. This approach has been used in other studies including the Department of Energy's *National Transmission Needs Study*.[1] For direct current lines, we use the lines' rated power-carrying capability in megawatts.

For alternating current lines, the voltage and length of each line segment are inputs from S&P Global Market Intelligence.[2] For each project, we calculated the power-carrying capabilities (MW) based on its voltage rating and length using Exhibit C1 below from the National Regulatory Research Institute.[3] The carrying capacity of projects that are composed of multiple line segments are limited by the longest segment. See Exhibit C2 below for the voltage, length, and approximate carrying capacity of each transmission project.

Exhibit C1: Approximate power-carrying capabilities of AC lines

Approximate power carrying capabilities (megawatts) of uncompensated AC transmission lines at different voltage ratings and lengths from the National Regulatory Research Institute

Line Length (mi)	Nominal Voltage (kV)					
	138	161	230	345	500	765
50	145	195	390	1,260	3,040	6,820
100	100	130	265	860	2,080	4,660
200	60	85	170	545	1,320	2,950
300	50	65	130	420	1,010	2,270
400	NA	NA	105	335	810	1,820
500	NA	NA	NA	280	680	1,520
600	NA	NA	NA	250	600	1,340

Table: RMI • **Source:** Department of Energy's National Transmission Needs Study and the National Regulatory Research Institute

Exhibit C2: Voltage, length, and approximate carrying capacity of each transmission project

Project	AC/DC	Voltage (kV)	Longest Line Segment Length (mi)	Carrying Capacity (MW)
Cross-Sound Cable	DC	150	24	300
TrAIL	AC	500	152	2,080
Paddock to Rockdale	AC	345	35	1,260
CAPX2020: Bemidji–Grand Rapids	AC	230	70	390
CAPX2020: Big Stone South–Brookings County–Hampton	AC	345	250	545
CAPX2020: Fargo–St. Cloud–Monticello	AC	345	240	860
CAPX2020: Hampton–La Crosse	AC	345	128	860
Beaver to Oklahoma City	AC	345	121	860
Bakersfield to Kendall	AC	345	139	860
Valley to Colorado River	AC	500	111	2,080

Table: RMI • **Source:** RMI analysis, S&P Global Market Intelligence, Department of Energy's National Transmission Needs Study, and the National Regulatory Research Institute

Congestion Relief Savings

The most commonly considered benefit of transmission is reductions in fuel and other variable operating costs of power generation and impacts on wholesale market prices.[4] At a high level, this benefit reflects increasing the use of more efficient (lower cost) generators over inefficient (higher cost) ones. Transmission enables this benefit by relieving flow constraints between two points on the system. In turn, this increases the use of more efficient generators over less efficient generators. It is commonly referred to as production cost savings or economic congestion savings.

Typically, planners at transmission developers or regional transmission organizations (RTOs) use production cost simulators to estimate this benefit by running a full computer simulation of a region's generators, transmission projects, and load centers. They do this analysis with and without a new transmission project or group of new projects and estimate the reduction in fuel and other variable operating costs with the new project(s). As such, this method is typically called production cost savings.

This analysis takes a different approach due to the ex-post nature of the analysis. It uses historical locational marginal prices (LMPs) in $/MWh between the starting node and the ending node of a transmission project and the estimated power transfer capacity (MW) of the project. This method reflects only the congestion relief between the starting and ending nodes, rather than the full production cost savings calculated through traditional methods.

Each line segment is assigned two market nodes that were chosen based on geographic proximity to each end of the line and available data.[i] We used historical hourly day-ahead and real-time locational marginal prices at each node from S&P Global Market Intelligence.[5] Exhibit C3 displays the two market nodes assigned to each line segment.

Exhibit C3: Pairs of market nodes assigned to each line segment

Line Segment	Node A	Node B
Cross—Sound Cable	SHOREHAM_IC_1	LD.E_SHORE 13.8
TrAIL	MEADOWBROOK 500 KV	502JCT 500 KV
Paddock to Rockdale	ALTE.TOWNEST12 / WEC.RBC1	ALTE.ROCKGEN3
CapX2020: Bemidji–Grand Rapids	OTP.SLWAYO1	MP.WPPI_BOS4
CAPX2020: Big Stone South–Brookings	OTP.BIGSTON1	NSP.BUFFR_TR1
CAPX2020: Brookings County–Hampton	NSP.BUFFR_TR1	NSP.CANFLSG2 / NSP.HAMPTN.MVP
CAPX2020: Monticello–St. Cloud	NSP.STCLOUD1	NSP.MNTCEL1
CAPX2020: Fargo–St. Cloud	OTP.ASHTUBULA	NSP.STCLOUD1
CAPX2020: Hampton–Rochester–La Crosse	NSP.CANFLSG2 / NSP.HAMPTN.MVP	NSP.FRENCH1
Beaver to Oklahoma City: Windspeed (Woodward to Oklahoma City)	OKGEWDWRD1LD2	OKGELONEOAK4LD2
Beaver to Oklahoma City: Beaver–Woodward	OKGEBVRCNTY7UNPALODURWND	OKGEWDWRD1LD2
Bakersfield to Kendall: Big Hill to Kendall	HHGT_KENDAL	LGD_LANGFORD
Bakersfield to Kendall: Bakersfield to Big Hill	LGD_LANGFORD	KEO_KEO_SM1
Valley to Colorado River: Devers–Valley	VALLEYSC_1_N107	DEVERS_1_N102
Valley to Colorado River: Devers–Colorado River	DEVERS_1_N102	BLYTHESC_1_GN001

Table: RMI • **Source:** RMI analysis and S&P Global Market Intelligence

For every hour of the time period considered, we multiply the difference in price between the two nodes by the estimated power transfer capacity. When the transmission project is not constrained, the two nodes do not have a price difference, resulting in no congestion relief savings during those hours in the analysis. The total congestion relief savings for the transmission project are then derived by summing the annual savings for each year the project is in service. Exhibit C4 provides an overview of the congestion relief analysis.

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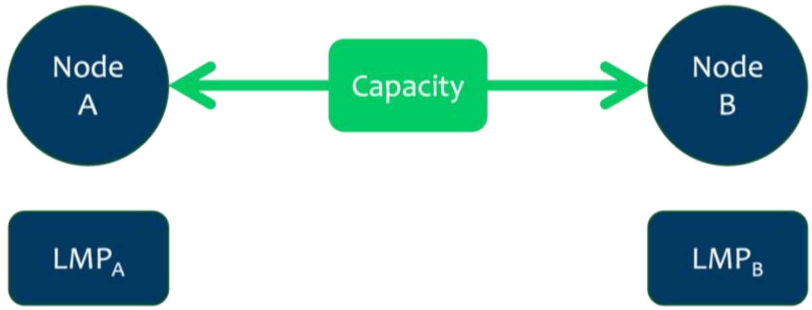
i If LMP data for a node was unavailable during part of the analysis period, a nearby node with comparable LMP data was used until the original node's data became available. For the Paddock to Rockdale line, the Paddock end of the line used the ALTETOWNEST12 node until November 30, 2012, then switched to the WEC.RBC1 node. For the Brooking County–Hampton and Hampton–Rochester–La Crosse lines, the Hampton end of the line used the NSP.CANFLSG2 node until November 30, 2017, then switched to the NSP.HAMPTN.MVP node.

Exhibit C4: Overview of congestion relief analysis



$$Annual\ Benefit = \sum_{h=0}^{8,760} |LMP_A - LMP_B| \times \text{Capacity}$$

Chart: RMI • **Source:** RMI analysis

This approach captures real economic benefits that are delivered to ratepayers in the period considered. These benefits are reflected in lower fuel and operating cost from the utility had the transmission project not been constructed.

Resource Adequacy Savings

Congestion relief savings only measure a reduction in the fuel and other operating costs of power generation. In addition to the everyday operations of the grid, grid operators must ensure that there is enough power plant capacity on their system to meet peak load in the future. Resource adequacy cost savings reflect reductions in capital and fixed costs of power plants to meet resource adequacy standards.[ii] Planners at transmission developers or RTOs use different methodologies to estimate this benefit. They can be framed using one of two approaches.

The first approach reflects the benefit delivered by gaining access to low-cost or existing excess generating capacity from a neighboring region. At a high level, this benefit reflects the lower cost of building and maintaining generators in one lower cost location over a higher cost location. Costs differences between locations can be a function of several different factors including land costs, infrastructure access, and fuel availability. Transmission enables access to this benefit by opening firm capacity between the two points on the system. The benefit associated with this approach is commonly referred to as access to lower cost generating resources or avoided capital cost of local resources.

ii Resource adequacy standards are standards to ensure the electric grid can supply enough electricity to meet demand under a range of future conditions. For example, a resource adequacy standard might be less than one day of outages in 10 years caused by a lack of generation. Once the target or metric is established, power system planners perform grid simulations of numerous possible power plant outages under different system conditions to ensure the system can achieve the resource adequacy standard. See Resource Adequacy Basics, National Renewable Energy Laboratory (NREL), https://www2.nrel.gov/research/resource-adequacy.

The second approach reflects the benefit delivered by reducing the reserve margin requirement or loss of load probability. Such reduction in planning reserves or loss of load probability directly translates into reduced need for generation capacity. At a high level, this benefit reflects the ability to rely on less generating capacity by strengthening connections with neighboring regions. Typically, planners will use resource adequacy models to simulate loss of load probabilities with and without a new transmission project or group of new projects and estimate the reduction in loss of load probabilities. This approach is commonly referred to as a benefit of reduced loss of load probability or reduced planning reserve margin requirements.

Both approaches can be used simultaneously because they reflect different benefits to the grid. The first approach reflects the ability to access lower cost capacity, while the second approach reflects the ability to lower the total capacity need. For example, MISO uses both approaches to estimate benefits in its Long-Range Transmission Planning process.[iii]

This analysis takes a different approach due to the ex-post nature of the analysis. It uses historical capacity market prices between the starting region and the ending region of a transmission project and the estimated power transfer capacity of the project.

For the Cross-Sound Cable project, we sourced historical capacity market clearing prices for ISO New England (ISO-NE) and New York ISO (NYISO) from S&P Global Market Intelligence, ISO-NE, and NYISO.[6] For each year the project was in service, we calculated the average capacity price of the Rest-of-Pool zone for ISO-NE and Zone K for NYISO.

For the Valley to Colorado River project, we sourced historical local capacity contract prices for CAISO from the CPUC's annual resource adequacy report.[7] For each year the project was in service, we used the weighted average flexible capacity price of the CAISO region for Blythe, CA, and the weighted average LA Basin price for Valley, CA.

Exhibit C5 presents the resource adequacy prices ($/kW-month) for the starting and ending regions of both transmission projects, beginning with the year they were energized.

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iii MISO estimates the *avoided capital cost of local resources* by running a capacity expansion model with and without the transmission portfolio to reflect the ability of load-serving entities to meet different resource adequacy and other constraints to their system at a lower cost. They also estimate *resource adequacy savings* by estimating the increase in transfer capability and a reduction in the total local capacity requirement. See, MISO, "LRTP Tranche 1 Portfolio Detailed Business Case", June 25, 2022, https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf.

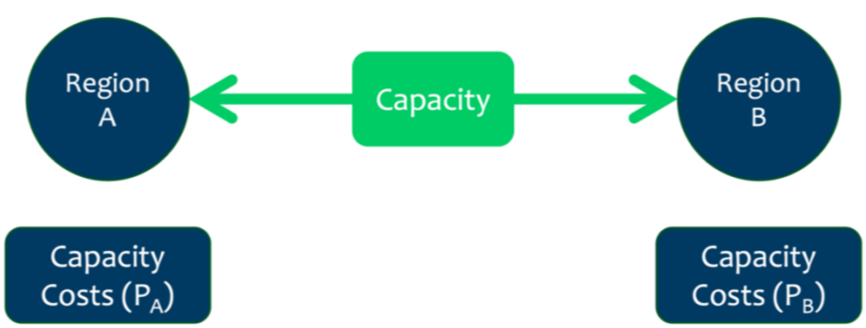
Exhibit C5: Resource adequacy prices ($/kW-month) for Cross-Sound Cable and Valley to Colorado River projects

Year	NYISO	ISO-NE	Valley, CA	Blythe, CA
2010	$1.67	$1.64		
2011	$0.29	$0.70		
2012	$1.85	$0.21		
2013	$4.86	$0.68	$3.27	$2.90
2014	$4.98	$1.20	$3.63	$2.86
2015	$4.20	$2.10	$3.44	$2.45
2016	$2.90	$1.27	$3.62	$2.44
2017	$3.62	$2.30	$3.48	$2.09
2018	$3.80	$1.79	$3.66	$2.76
2019	$3.11	$1.41	$3.80	$2.79
2020	$2.82	$1.05	$5.11	$4.65
2021	$5.39	$1.17	$6.64	$5.27
2022	$4.42	$1.09	$7.54	$6.61
2023	$4.42	$1.87	$7.54	$6.61

Table: RMI • **Source:** RMI analysis, S&P Global Market Intelligence, NYISO, ISO-NE, and CPUC

We calculated resource adequacy savings by multiplying the difference in capacity market price between the two regions by the project's estimated power transfer capacity. The total resource adequacy savings for the transmission project are then derived by summing the annual savings for each year the project is in service. Exhibit C6 provides an overview of the resource adequacy analysis.

Exhibit C6: Overview of resource adequacy analysis



$$Annual\ Benefit = |P_A - P_B| \times \text{Capacity}$$

Chart: RMI • **Source:** RMI analysis

This approach captures real economic benefits that are delivered to ratepayers in the period considered. These benefits are reflected in lower capital investments in resource adequacy costs from the utility had the transmission project not been constructed.

Public Policy Savings

Public policy savings measure the benefits achieved when a transmission project enables renewable energy deployment by connecting low-cost resources, such as wind and solar, to the broader grid. At a high level, this benefit reflects the reduced cost of renewable energy production in resource-rich areas, where solar irradiance or wind speeds are higher.

Our analysis calculated this benefit by comparing the levelized cost of energy in dollars per megawatt-hour ($/MWh) between individual wind and solar plants enabled by the transmission line to the average cost of resources of the same type across the regional transmission organization. Each plant and resource type were evaluated independently.

Solar and wind plants are considered "enabled" if they are located within 15 miles of the project and were energized after the transmission project became operational.[iv] We identified enabled power plants using the S&P Global Market Intelligence mapping tool.[8]

The levelized cost of energy for the enabled plants was estimated using the National Renewable Energy Laboratory's annual technology baseline (NREL ATB).[9] We used the plant's 2022 capacity factor to assign an NREL wind and solar class. That class was subsequently converted into a levelized cost of energy.

Exhibit C7 and Exhibit C8 below show the capacity factor and levelized cost of energy from NREL 2024 ATB for utility-scale solar PV and land-based wind classes, respectively. We use the NREL 2024 ATB for all resources, regardless of vintage, to isolate the difference in quality between the enabled resources and the RTO-wide resources, eliminating the influence of other factors such as technology change and individual plant specifications.

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iv We also include power plants that were operational within one year of the transmission line being energized.

Exhibit C7: Utility-scale solar PV classes

Utility-scale solar PV class with associated net capacity factor and levelized cost of energy from the National Renewable Energy Laboratory's annual technology baseline

Utility-Scale Solar PV Class	2022 Net Capacity Factor (%)	2022 Levelized Cost of Energy ($/MWh)
1	31%	$39.05
2	30%	$40.37
3	29%	$42.38
4	28%	$44.50
5	26%	$46.84
6	25%	$49.40
7	24%	$52.07

Table: RMI • **Source:** National Renewable Energy Laboratory

Exhibit C8: Land-based wind classes

Land-based wind class with associated net capacity factor and levelized cost of energy from the National Renewable Energy Laboratory's annual technology baseline

Land-Based Wind Class	2022 Net Capacity Factor (%)	2022 Levelized Cost of Energy ($/MWh)
1	50%	$29.50
2	47%	$31.44
3	46%	$32.16
4	45%	$33.04
5	43%	$34.16
6	41%	$36.06
7	38%	$39.09

Table: RMI • **Source:** National Renewable Energy Laboratory

The levelized cost of energy for the RTO-wide average was similarly estimated. We used the weighted average capacity factor of wind and solar plants built between 2017 and 2022 within the RTO.[10] This averaged capacity factor was used to determine the corresponding NREL wind and solar class, which was then converted into a levelized cost of energy.[11] Exhibit C9 presents the weighted average capacity factor, corresponding NREL resource class, and levelized cost of energy used in the public policy analysis for each RTO and generation type.

Exhibit C9: Average capacity factor, NREL resource class, and levelized cost of energy by RTO and generation type

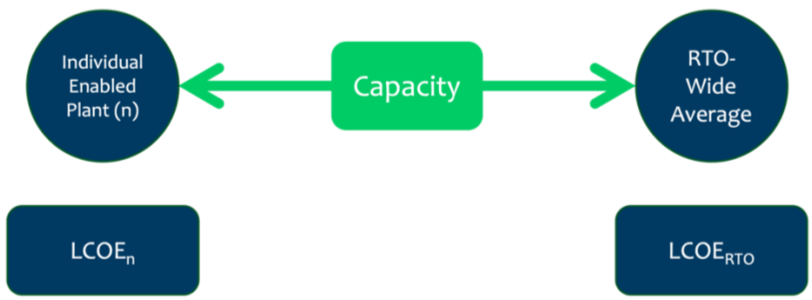
Weighted average of wind and solar plants built between 2017 and 2022

RTO	Generation Type	Average Capacity Factor (%)	NREL Resource Class	Levelized Cost of Energy ($/MWh)
SPP	Wind	38%	7	$39.09
ERCOT	Wind	36%	7	$39.09
ERCOT	Solar	23%	7	$52.07
CAISO	Solar	23%	7	$52.07
MISO	Wind	38%	7	$39.09

Table: RMI • **Source:** RMI analysis, S&P Global Market Intelligence, the National Regulatory Research Institute, National Renewable Energy Laboratory, and Lawrence Berkeley National Lab

For each enabled plant (denoted by *n* in the equation within Exhibit C10), we calculate annual public policy savings by multiplying the difference between its levelized cost of energy and the RTO-wide average by its annual generation. The total public policy savings for the transmission project are then derived by summing the savings of all eligible plants for each year the project is in service. We ensure that the capacity of enabled generation does not exceed the capacity of the transmission line. Exhibit C10 provides an overview of the public policy analysis.

Exhibit C10: Overview of public policy analysis



$$Annual\ Benefit = \sum_{n=0}^{n=Capacity} [LCOE_n - LCOE_{RTO}] \times \text{Generation}_n$$

Note: n represents each enabled plant. We ensure that the capacity of enabled generation does not exceed the capacity of the transmission line.

Chart: RMI • **Source:** RMI analysis

This approach captures real economic benefits that are delivered to ratepayers in the period considered. These benefits are reflected in lower public policy costs had the transmission project not been constructed.

Transmission Costs

Transmission costs are calculated using different models depending on the transmission ownership structure. This section provides an overview of the financial models we used to calculate transmission costs for each of the three types of ownership structures. For projects that are jointly owned by multiple utilities, the largest share owner is used for the financial model. The seven projects we evaluated include:

- Five owned by investor-owned utilities;
- One owned by public power utilities; and
- One owned by an independent merchant developer.

The rate mechanisms for all ownership structures distribute the full construction, financing, regulatory, and operational costs over the project's 40-year financial life. We used a 40-year financial life for our financial model to be conservative. However, transmission projects can be depreciated over a longer period. For example, some utilities use a 55-year life for transmission lines.

This subsection is divided by investor-owned utilities, public power utilities, and independent merchant developers.

Investor-Owned and Public Power Utilities

Transmission costs for investor-owned and public power utilities are calculated as the annual revenue requirement to repay the cost of the line over the project's 40-year financial life. Components included in the revenue requirement are listed in Exhibit C11. These components are explored in more detail in the subsections below.

Exhibit C11: Investor-owned and public power utilities include distinct components in their revenue requirements

Expense	Investor-owned utility	Public power utility
Fixed operational and maintenance	X	X
Interest	X	X
Depreciation	X	X
Property taxes	X	X
State and federal taxes	X	
Return on equity	X	
Debt coverage		X

Table: RMI • **Source:** RMI analysis

Investor-Owned Utilities

The annual revenue requirement for investor-owned utilities is calculated as follows:

$$Annual\ Revenue\ Requirement = Interest + Return\ on\ Equity + Depreciation + State\ and\ Federal\ Taxes + Fixed\ Operation\ \&\ Maintenance + Property\ Taxes$$

Rate base refers to the total value of a utility's assets that are used to provide services to customers, which are eligible to earn a return on investment. The financial model calculates the rate base annually using the total construction cost, a 20-year modified accelerated cost recovery system, and a 40-year financial life. It is used for calculating certain components of the revenue requirement.

$$Rate\ Base = Gross\ Plant\ Value - Accumulated\ Depreciation - Deferred\ Income\ Tax$$

Interest refers to the annual costs incurred from borrowing funds to finance the construction of the project. These expenses are typically associated with loans or bonds issued to secure capital for the project. Interest payments are made over the duration of the financing period and are proportional to the remaining balance on the debt. The financial model calculates the interest costs by multiplying rate base by percentage financed by debt by the debt interest rate.

$$Interest = Rate\ Base \times \%\ Debt \times Debt\ Interest\ Rate\ (\%)$$

Return on equity refers to the profit a transmission-owning utility earns in relation to its shareholders' equity. The return on equity is a metric used by regulators to determine a utility's ability to generate profits from its investments, as determined by the Federal Energy Regulatory Commission (FERC). The financial model calculates return on equity by multiplying the cost of equity by the percentage financed by equity.

$$Return\ on\ Equity = Rate\ Base \times \%\ Equity \times Cost\ of\ Equity\ (\%)$$

Depreciation refers to the annual costs incurred from the utility recouping the costs of the asset over time. Since transmission infrastructure requires large up-front capital investment, depreciation allows the utility to recover the initial cost of the assets over their useful life. The financial model assumes a straight-line depreciation over 40 years.

$$Depreciation = \frac{Total\ Construction\ Costs}{40\ Years}$$

State and federal taxes refer to the annual state and federal income taxes incurred by the utility. Investor-owned utilities are subject to both federal and state income taxes. The financial model calculates this by multiplying their combined state and federal effective tax rate by their return on equity plus a gross up. The gross up ensures that the utility hits their return on equity after taxes are taken out. The effective tax rate is based on an individual utility's FERC formula rate filing in the year that the line was energized and switches to a different rate post-2018 to reflect the change in the federal rate. The post-2018 rate is based on an individual utility's FERC formula rate filing in 2023.

$$State\ and\ Federal\ Taxes = Return\ on\ Equity \times Effective\ Tax\ Rate + Gross\ Up$$

$$Gross\ Up = \frac{State\ and\ Federal\ Taxes \times Effective\ Tax\ Rate}{(1 - Effective\ Tax\ Rate)}$$

Fixed operational and maintenance refers to the annual costs incurred to operate and maintain the transmission project. The financial model assumes that this cost is 1% of total construction costs.

$$Fixed\ Operational\ \&\ Maintenance = Total\ Construction\ Costs \times 1\%$$

Property taxes refer to the annual costs incurred based on the assessed value of the utility's assets. These taxes are typically assessed by local or state governments. The financial model assumes that this cost is 0.6% of the depreciated asset value over 20 years.

$$Property\ Taxes = Depreciated\ Asset\ Value \times 0.6\%$$

For investor-owned utilities, we used FERC formula rate filings from the year in service for fixed operational and maintenance costs, debt to equity ratio, cost of debt, cost of equity, pre-2018 effective tax rate, and post-2018 effective tax rate. We used S&P Global Market Intelligence, FERC formula rate filings, FERC form 1 filings, and utility filings and reports for construction costs.[12] When possible, we compare multiple sources to confirm the total construction cost of a project. Exhibit C12 displays the financial inputs for projects owned by investor-owned utilities.

Exhibit C12: Financial inputs for projects owned by investor-owned utilities

	Online Date	Construction Costs	Fixed O&M	Debt to Equity Ratio	Cost of Debt	Cost of Equity	Pre-2018 Composite Tax Rate	Post-2018 Composite Tax Rate	State Property Tax
TrAIL	2011	$786M	1.00%	40.10%	4.89%	11.70%	39.97%	26.86%	0.6%
Paddock to Rockdale	2010	$133M	1.00%	50.00%	5.24%	12.22%	40.65%	24.44%	0.6%
CapX2020 Bemidji–Grand Rapids	2012	$67M	1.00%	47.00%	4.82%	12.38%	40.81%	28.03%	0.6%
CapX2020 Big Stone South–Brookings	2017	$126M	1.00%	47.00%	4.82%	12.38%	40.81%	28.03%	0.6%
CapX2020 Brookings County–Hampton	2015	$607M	1.00%	47.00%	4.82%	12.38%	40.81%	28.03%	0.6%
CapX2020 Monticello–St. Cloud	2015	$557M	1.00%	47.00%	4.82%	12.38%	40.81%	28.03%	0.6%
CapX2020 Hampton–Rochester–La Crosse	2016	$214M	1.00%	47.00%	4.82%	12.38%	40.81%	28.03%	0.6%
Windspeed (Woodward to Oklahoma City)	2010	$204M	1.00%	45.59%	6.09%	12.10%	38.97%	24.30%	0.6%
Beaver - Woodward	2014	$247M	1.00%	46.47%	5.51%	12.10%	38.75%	24.30%	0.6%
Valley to Colorado River	2013	$734M	1.00%	52.32%	5.24%	9.80%	40.40%	27.98%	0.6%

Table: RMI • **Source:** S&P Global Market Intelligence, FERC Form 1, FERC Formula Rate, and Individual Utility Filings

Public Power Utilities

The annual revenue requirement is calculated as follows for public power utilities:

$$\begin{aligned} Annual\ Revenue\ Requirement = {} & Interest + Coverage\ of\ Debt\ Service + Depreciation \\ & + Fixed\ Operational\ \&\ Maintenance + Property\ taxes \end{aligned}$$

Interest, depreciation, fixed operational and maintenance, and **property taxes** are calculated using the same methodology outlined in the investor-owned utilities section. Public power utilities are not subject to **state and federal taxes** because they are nonprofit entities. The primary difference between the ownership structures is that public power utilities do not earn a **return on equity** but rather have additional **coverage of debt service**. This enables them to have financial flexibility to pay debt service and other fixed charges in the event of a downturn in revenue or an increase in operating costs.

Coverage of debt service refers to a utility's ability to generate sufficient cash flow to meet (a) its debt obligations (both interest and principal) and operating expenses and (b) additional cash flow to sustain operations and invest in infrastructure. Utilities typically target a debt service coverage ratio to satisfy both objectives. The financial model calculates a coverage of debt service by ensuring that total revenues divided by its total debt service expenses, property tax expenses, and fixed operational and maintenance expenses are equal to the debt service coverage ratio for a utility.

$$Debt\ Service\ Coverage\ Ratio = \frac{Total\ Revenues}{Principle\ +\ Interest\ +\ Property\ Taxes\ +\ Fixed\ Operational\ \&\ Maintenance}$$

$$Coverage\ of\ Debt\ Service = \big((Principle + Interest) * Debt\ Service\ Coverage\ Ratio\big) - Interest - Depreciation$$

For public power utilities, we used individual filings from transmission owners from the year in service for fixed operating and maintenance costs, percentage debt, cost of debt, debt coverage rate, and state property tax rate. We used S&P Global Market Intelligence as well as utility filings and reports for construction costs.[13] When possible, we compare multiple sources to confirm the total construction cost of a project. Exhibit C13 displays the financial inputs for projects owned by public power utilities.

Exhibit C13: Financial inputs for projects owned by public power utilities

	Online Date	Construction Costs	Fixed O&M	Debt to Equity Ratio	Cost of Debt	Debt Coverage Ratio	State Property Tax
Big Hill to Kendall	2013	$374M	1.00%	75%	4.34%	1.35	0.60%
Bakersfield to Big Hill	2013	$137M	1.00%	83%	4.56%	1.35	0.60%

Table: RMI • **Source:** S&P Global Market Intelligence, Texas PUC, Lower Colorado River Authority Transmission Services Corporation, and the Southern Texas Electric Company

Independent Merchant Developers

For independent merchant developers, the total annual revenue requirement is a lease charge for the transmission rights across the line. This is typically paid for by one or more utilities that rent the transmission rights. Independent merchant developers will structure their rate mechanisms differently depending on their lease arrangements and market structures.

We used individual filings from New York State to obtain lease charges for the transmission rights on the Cross-Sound Cable project.[14] Exhibit C14 displays the financial inputs for the project owned by the independent merchant developer.

Exhibit C14: Financial inputs for projects owned by merchant developers

	Total Expenditure	Years	Annual Expenditure
Cross-Sound Cable	$514M	29	$18M

Table: RMI • **Source:** New York Office of State Comptroller

Anticipated Benefit-Cost Analyses

The primary output of our benefit-cost analysis is a benefit-to-cost ratio. When possible, we compare this ratio with the anticipated benefit-to-cost ratio from the project's original plans. Of the seven case-studies, only three projects evaluated economic benefits and included benefit-to-cost projections in their original plans. This section describes the benefit-to-cost projections for each project.

Paddock to Rockdale

We used American Transmission Company's (ATC) planning assessment of the Paddock to Rockdale line for the anticipated benefit-to-cost ratio.[15] ATC evaluated six benefits across seven plausible futures, identifying an anticipated benefit-to-cost ratio of 0.5–5.2 and a median ratio of 3.2 based on the project's original plans.[v]

The ATC analysis evaluated benefits using four different approaches: Adjusted Production Costs (adjusted for imports and exports), 70% of Adjusted Production Costs and 30% Load-Weighted LMP, Load-Weighted LMP, and ATC customer benefits metric. We used the Adjusted Production Cost method for comparison, as it best aligned with our approach to calculating societal ratepayer savings.

The ATC analysis calculated costs and benefits using net present value over the 40-year life of the project using a 3% inflation factor and an 8.5% discount rate. This is aligned with our methodology, albeit with a higher inflation rate and discount rate.

Beaver to Oklahoma City

We used Southwest Power Pool's planning assessment for the Priority Project portfolio for the Beaver to Oklahoma City anticipated benefit-to-cost ratio.[16] The Windspeed Transmission (Woodward–Oklahoma City) segment of the project did not have a benefit-to-cost analysis conducted during its planning process. However, the Beaver–Woodward segment was part of

v The median anticipated benefit-to-cost ratio for the Paddock to Rockdale project was calculated using the results from Table 32 on page 63 of Planning Analysis of the Paddock–Rockdale Project, American Transmission Company, April 5, 2007, https://www.atcllc.com/oasis/Customer_Notices/Filed_CPCN_Economic_Analysis_PR_051607.pdf.

SPP's portfolio of Priority Projects and underwent an economic impact study. The Priority Projects economic study evaluated two project portfolios across five benefit categories, with the Beaver—Woodward project included in both. Oklahoma Gas and Electric had a benefit-to-cost ratio of 1.19 in Study Group 1 and 1.48 in Study Group 2.[17] As Study Group 2 was ultimately recommended and approved by SPP, we used the benefit-to-cost ratio of 1.48 in our analysis of the Beaver to Oklahoma City project.[18]

The SPP analysis evaluated benefits using two approaches: with and without wind revenues and fuel diversity benefits. We used the approach that included wind revenues and fuel diversity benefits for comparison, as it better aligned with our analytical approach for calculating public policy savings from enabled power plants.

The SPP analysis calculated costs and benefits using net present value over the 40-year life of the project using a 2.18% inflation factor and an 8% discount rate. This is aligned with our methodology, albeit with a lower inflation rate and higher discount rate.

Valley to Colorado River

We used CAISO's planning assessment of the originally proposed Arizona to California transmission line for the Valley to Colorado River anticipated benefit-to-cost ratio.[19] Assessed using CAISO's Transmission Economic Assessment Methodology, the original project had an anticipated benefit-to-cost ratio of 1.2–3.2. While the Arizona portion was canceled, the California-only Valley to Colorado River project was approved by the California Public Utilities Commission (CPUC), assuming it would still provide net benefits.[20]

The CAISO analysis calculated benefits using four approaches: WECC or Societal, Enhanced WECC Competition or Modified Societal, CAISO Ratepayer (LMP Only), and CAISO Ratepayer (LMP+ Contract Path). We used the Enhanced WECC Competition or Modified Societal for comparison, as it best aligned with our approach to calculating societal ratepayer savings.

The CAISO analysis calculated costs and benefits using net present value over the 40-year life of the project using a 2% inflation factor and a 10% discount rate. This is aligned with our methodology, albeit with a lower inflation rate and higher discount rate.

Limitations and Conservatisms of Our Approach

Below, we summarize key limitations and conservatisms of our analytical approach.

Limited Benefits

Our study focused on three core transmission benefits: congestion relief savings, resource adequacy savings, and public policy savings. However, transmission offers more benefits than the analysis quantified and accounted for. MISO's long-range transmission planning identified six benefit categories and The Brattle Group outlines eight benefit categories.[21] Therefore, our estimate of net benefits is likely conservative because other methodologies include many more benefits than we considered.

Additionally, going forward, grid planners will be required by FERC Order No. 1920-A to plan for and quantify seven specific benefits.[22] This means our analysis likely underestimates the full range of benefits that grid planners will be using in the coming years.

Transmission Capacity

We evaluate transmission lines in isolation to directly assess their associated benefits and costs. For alternating current lines, we do this by estimating their incremental power-carrying capabilities based on mileage and voltage — the physical characteristics most directly influencing a line's capacity. Traditionally, however, determining transmission capacity involves power flow simulations that account for more complex factors, such as line impedance, voltage constraints, dynamic stability, and system-wide interactions. These factors result in transmission capacities that vary depending on network configuration, operational constraints, and environmental conditions. Due to these complex grid interactions, we would expect the actual carrying capacity of the lines to differ from our estimates in both an upward and downward direction.

Additionally, our approximation of an alternating current line's capacity is based on uncompensated transmission lines. However, over long distances, many utilities use compensated transmission lines to enhance power transfer capabilities. Compensated transmission lines use strategically placed capacitors to mitigate volage drops and enhance power transfer capabilities. As such, the actual carrying capacity of the lines may exceed our estimates.

Nevertheless, our estimates of carrying capacity in isolation is a reasonable attempt to calculate the associated benefits and cost of each line. This approach has been used in other studies including the Department of Energy's *National Transmission Needs Study*.[23]

Transmission Outages and Derates

We do not account for transmission outages or derates in our model. In practice, weather events, scheduled maintenance, and unforeseen equipment failures can cause lines to be derated or taken offline temporarily. During such periods, the effective carrying capability of the lines would be lower than our assumptions. By not accounting for outages and derates, we are likely overvaluing the congestion relief and resource adequacy savings during these periods.

However, transmission outages and derates are relatively uncommon. Most outages and derates are planned during non-critical periods where benefits would be minimal or non-existent. For example, a utility might do a planned outage in the spring when load is low and there is no congestion along the line.

Marginal Value of Congestion Relief and Resource Adequacy Savings

The congestion relief and resource adequacy savings were calculated using observed historic price differences between two nodes on the grid. This price difference represents the marginal cost — the cost of the next unit of electricity required to meet demand. This approach provides a conservative estimate because, without the transmission line, the price disparity would likely be even greater.

This holds true for both congestion relief and resource adequacy. At the higher-priced node, more energy or capacity would need to be acquired, driving prices up. Conversely, at the lower-priced node, less energy or capacity would be needed, pushing prices down. Overall, this would increase the price disparity. As a result, calculating the true counterfactual scenario — where operating or fixed costs of power generation are higher without the additional transmission capacity — would likely reveal a higher economic value for the transmission.[vi]

Minimal Overlap Between Congestion Relief and Public Policy Savings

Transmission infrastructure improves access to high-quality, cost-effective renewable energy, reducing both overall electricity costs and the cost of meeting clean energy targets. In our analysis, congestion relief savings occur when transmission investments allow cheaper power to flow while more expensive generators remain on standby, thereby lowering fuel costs; whereas public policy savings reflect the reduced cost of procuring clean energy. They are related but overlap minimally.

Utilities often meet clean energy targets by purchasing renewable energy through agreements known as power purchase agreements (PPAs) or by directly investing in clean energy projects. Transmission enables utilities to source PPAs at a lower cost than they might otherwise within their region. For example, instead of buying renewable energy from a more expensive local project, a utility can access cheaper wind or solar power from another part of the grid via transmission lines. This benefit is reflected in the public policy savings.

At the same time, transmission improves access to lower-cost electricity, partly enabled by the same renewable power plants. This is known as production cost savings, which occur when new generation helps lower the total cost of electricity in an area. In our congestion relief analysis, however, production cost savings are only recognized when an LMP spread exists across the transmission line (i.e., when there is congestion on the line). Therefore, not all cost reductions are captured under congestion relief savings.

Ultimately, while congestion relief and public policy savings stem from increased access to cheaper power, they have minimal overlap. They serve two distinct purposes for utilities: providing lower-cost energy to customers and meeting clean energy goals.

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vi We did not calculate the true counterfactual scenario due to its complexity and need for additional assumptions, opting instead to rely on observed data.

Interregional Pricing Inefficiencies

For the two interregional projects, we assume that there is perfect optimization of pricing between two RTOs in our congestion relief analysis. However, there are well-documented seam-related inefficiencies between markets. For example, the 2024 *PJM State of the Market* report indicates that power flows in the wrong direction between PJM and MISO approximately 45% of the time.[24] Additionally, the market monitor between NYISO and ISO-NE found that "the efficiency of real-time trades has been deteriorating, achieving 'optimal' real-time transactions during only 11% of all trading periods in 2022, down from 23% in 2018."[25] We are likely overestimating the congestion relief savings due to these market-seam related inefficiencies. Regardless, regional transmission organizations could address this problem by implementing intertie optimization across the seam.[vii]

Furthermore, market-seam-related inefficiencies are most prevalent during real-time trading. Our analysis primarily relies on day-ahead prices, with a weighting of 90% for day-ahead prices and 10% for real-time prices in the congestion relief analysis. This limits the impact of the seam-related inefficiencies.

Quantity of Enabled Generation

The public policy analysis ensured that the enabled generation capacity did not exceed the transmission line's carrying capacity. As discussed, we evaluated an alternating current line's carrying capacity in isolation based on its mileage and voltage. However, in a meshed, integrated grid, the enabled generation capacity from an alternating current line may not align with its carrying capacity. The amount of enabled generation may be higher or lower.

For instance, the Cardinal Hickory Creek project in MISO is a 345 kV line of 102 miles. By our estimate, it has a carrying capability of 860 MW. Yet, along with other projects in the MISO Multi-Value Projects portfolio, it enabled over 24.5 GW of wind and solar generation.[26] Consequently, had we included the Cardinal Hickory Creek project in our analysis, the actual generation enabled — and the associated public policy savings — would likely have been higher than our estimate.

Location of Enabled Generation

The public policy analysis assumes that a transmission project enables solar and wind plants if they are located within 15 miles of the project. However, additional plants beyond this range are also likely enabled. For example, the Cardinal Hickory Creek project in MISO enabled over 24.5 GW of wind and solar plants throughout the MISO footprint, with many plants located well beyond 15 miles from the project.[27] Because our analysis only includes enabled generation within the 15-mile range, we expect the public policy benefits to be larger than our estimates.

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vii The Brattle Group and Willkie Farr and Gallagher identify market seam–related trading inefficiencies as a problem and propose using intertie optimization as a solution. See Johannes P. Pfeifenberger et al., *The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, October 2023.

Financial Inputs

Financial inputs are based on the FERC formula rate filings for the year the project is placed in service. These inputs reflect the average values for the entire transmission portfolio owned by the utility. However, individual transmission projects may have different financing provisions than the rest of the portfolio. For example, the cost of debt may vary depending on the year the debt was issued. As a result, the financial inputs for individual projects could differ from the overall transmission portfolio.

Overall, we expect that the financial inputs derived from the FERC formula rates — representing the project portfolio — provide a reliable measure of a transmission project's long-term cost. Since utility finances and global markets fluctuate regularly, basing estimates on the entire portfolio makes the analysis less susceptible to single-year variations that may not accurately reflect the utility's overall financial reality.

Other Rate Mechanisms

Financial inputs are based on FERC formula rate filings for the project's in-service year. These inputs reflect the average inputs of the entire transmission portfolio owned by the utility. However, individual projects may have distinct rate mechanisms designed to incentivize utilities to build transmission, such as return-on-equity adders and financing mechanisms like construction work in progress.[viii] These rate mechanisms were not explicitly accounted for in our cost analysis of individual projects. However, such adders and financing mechanisms are incorporated into the broader FERC formula rate filing and are reflected to some extent in our financial inputs. For example, a return-on-equity adder for an individual project would be incorporated into the overall return-on-equity rate for the entire portfolio of projects as part of the FERC formula rate filing.

Since many of our projects are large and involve higher risks — types of projects that typically qualify for additional rate incentives — there is a possibility we slightly underestimated transmission costs. Fully understanding this impact, however, would require a case-by-base evaluation of each project. We did not take this approach due to the difficulty of isolating a single line within a FERC formula rate filing.

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viii Return on equity (ROE) adders refer to additional incentives or adjustments made to the base ROE, granted to transmission owners under certain conditions. These adders are designed to encourage investment, improve system reliability, or meet regulatory or operational targets. Construction work in progress (CWIP) is an accounting mechanism in which all costs associated with the construction of new transmission facilities are recorded until the facilities are placed in service. Typically, utilities are not allowed to begin recovery of the costs until they are placed in service. However, in certain cases, utilities can recover costs within CWIP.

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