Congestion Cost Savings Test for Economic Evaluation of ERCOT Transmission Projects

Prepared for ERCOT

March 2024

Energy+Environmental Economics

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Acknowledgements

We are grateful to the following individuals for highly helpful discussions of economic tests and transmission planning in their regions: Sameh Al-Eryani Nick Jansen, & Connor Sekac (AESO), Julius Susanto (Australian Energy Market Commission, AEMC), Xiaobo Wang (CAISO), Martin Kavanagh (EirGrid), Ping Yan & Pengwei Du (ERCOT), Patrick Boughan (ISO-NE), Christina Drake (MISO), Jason Frasier & Ross Altman (NYISO), Eric Hsia & Nicolae Dumitriu (PJM), and Nick Parker (SPP).

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1 Executive Summary

In 2021, the Texas Legislature passed SB 1281, which prompted the Public Utility Commission of Texas (PUCT) to amend Public Utility Commission (PUC) Rule 25.101 in December 2022. This amended rule directs ERCOT to develop a congestion cost savings test to evaluate the savings that a transmission line would create for ERCOT energy consumers when determining whether to support a transmission upgrade as economically beneficial. ERCOT has been exploring options for a congestion cost savings test (often referred to in the industry as a consumer benefits test) that would fit well for the ERCOT market. ERCOT hired Energy and Environmental Economics, Inc. (E3) as its consultant to support ERCOT by reviewing options for congestion cost savings tests and provide a recommendation of a benefits test that would fit best with the ERCOT market structure.

To provide a wide range of options for ERCOT to consider, E3 reviewed economic benefits tests used for transmission planning in other jurisdictions throughout North America, as well as in Australia and Ireland. E3 created a set of criteria to identify which options would be most applicable in estimating the potential transmission benefits for ERCOT load customers. Based on the options reviewed, E3 recommends a System-Wide Gross Load Cost (GLC) Test as the best option to fit with the rules and structure of the ERCOT market.

The System-Wide GLC Test directly estimates the impact of new transmission on the energy costs for ERCOT consumers by calculating how transmission changes the total payment for energy consumption incurred by ERCOT load customers. This approach evaluates how a proposed transmission project changes wholesale market prices paid across all ERCOT customer locations and multiplies those price savings by the MWh of energy customers consume in the corresponding locations. The approach enables ERCOT to then compare this consumer cost savings against the cost of building the transmission project in order to determine whether the project would produce positive net savings to ERCOT consumers.

This approach has a clear link to ERCOT customer savings and a sound fit with key features of the ERCOT market. The approach is able to positively identify the potential benefit of reducing congestion in the ERCOT system, and it is straightforward to implement using ERCOT's existing study approach and software. It also provides a complementary perspective that is distinct from the Production Cost Savings Test, which ERCOT will also continue to use for transmission benefit evaluation in parallel with the consumer benefits test.

The System-Wide GLC Test may not fully capture the impact of partially hedging to congestion costs by ERCOT load customers through purchases of Congestion Revenue Rights (CRRs) in auctions, and through the proceeds of those auction, which ERCOT returns to customers. Recent annual reports by ERCOT's market monitor indicate that CRRs allow ERCOT loads to be partially but not fully hedged to congestion costs in the system. Therefore, E3 recommends that it may be useful for ERCOT to continue to review available data that may be useful for estimating the aggregated impact of congestion, including auction revenue allocation, on ERCOT loads. In future study work, ERCOT may consider using this information to refine the System-Wide GLC Test and customize the test for the ERCOT market, provided that this refinement does not introduce excessive noise or uncertainty to study results and does not materially slow down the study process.

2 Study Purpose and Approach

2.1 Study Purpose and Context

In 2021, the Texas Legislature passed SB 1281, which prompted the Public Utility Commission of Texas (PUCT) to amend to Public Utility Commission (PUC) Rule 25.101 (Rule) in December 2022. This amended rule directs ERCOT to develop a congestion cost savings test (often referred to in the industry as a consumer benefits test) for evaluating whether to approve a transmission upgrade as economically beneficial for the ERCOT power system. ERCOT has been exploring options for congestion cost or consumer benefits tests that would fit well with the ERCOT market, and ERCOT hired Energy and Environmental Economics, Inc. (E3) as its consultant to support ERCOT's evaluation. This report summarizes E3's analysis and recommendations.

This analysis is specifically focused on economic-driven need for transmission projects, which is distinct from reliability-driven transmission projects. In ERCOT, like other North American power markets, most transmission lines[1] that are added to the grid are selected and approved because they are necessary to maintain reliability of the transmission system. Regulators and system planners develop a set of engineering-based reliability planning standards for the transmission system, and if the current transmission system does not meet one or more of these standards, then an upgrade is required to improve reliability up to at least the minimum criteria set in these standards.

In the other situations, however, a transmission upgrade is not immediately needed to maintain reliability, but still may provide economic savings to the power system by enabling more efficient operations. If potential economic savings from a new line or upgrade is greater than the cost of constructing the new line or upgrade, the line or upgrade can provide positive net benefits to ERCOT consumers.

For the past two decades, ERCOT has utilized an evaluation technique called a Production Cost Savings Test to evaluate the potential economic benefits of a new transmission project. A Production Cost Savings Test evaluates economic impact of adding a line from a "societal" perspective, which means that it looks at the aggregate benefits to all power market participants, including load customers, generators, and transmission owners or rights holders, without consideration of the distribution of those benefits among these three categories of participants. Also described as an "economic efficiency test", Production Cost Savings Tests are utilized in the majority of North American power jurisdictions, and involve simulating the least-cost solution for the dispatch of all generating resources in the power system to serve load while respecting transmission limits and other operational constraints, and then calculating the change (if any) in the cost of that resource dispatch in a scenario with a new transmission project addition, compared to a Base Case without the new project.

By contrast, a consumer benefits test evaluates a transmission project's economic impact solely on power customers (load customers) rather than the impact of the project to all categories of market participants.

[1] In this report, the term "transmission project" is used interchangeably with "lines" or "upgrades" for describing potential new transmission system additions that are not yet in service.

A consumer benefits test, which is sometimes referred to as a congestion cost savings test, must therefore calculate the effect that a line would have on the distribution of costs and revenues from payments between different categories of market participants (loads customers, generators, and transmission owners) so that it can distinguish the specific impact to consumers. Utilization of a consumer benefits test in ERCOT is supported by the fact that ERCOT transmission costs are charged directly to ERCOT load customers. Therefore, the total delivered power cost for these power consumers is the sum of

(1) the customers' cost for energy, plus

(2) the cost of charges to build, finance, and maintain the transmission system.

If adding a new line will reduce the consumers' cost of energy by a larger amount than the amount that transmission cost must increase to pay for the new transmission project, then the line would reduce the total cost of delivered power to customers and therefore have positive net benefits to consumers.

Prior to 2012, ERCOT utilized a type of consumer benefits test called the Generator Revenue Reduction (GRR) Test. ERCOT used this test as a supplementary economic test to ERCOT's Production Cost Savings Test for evaluating transmission projects. The GRR Test seeks to estimate the impact of a line to ERCOT customers by calculating how the line would reduce the sum of annual payments to generators for energy. The GRR Test implicitly assumes that all congestion revenue[2] in the system is returned to consumers. This report will discuss the GRR Test in more detail in section 4.2.1 and compare it to other potential consumer benefit test options. Between 2013 and 2022, ERCOT discontinued the use of the GRR test and used solely the Production Cost Savings Test for economic transmission evaluations.

In 2022, the PUCT's amendments to Rule 25.101 directed ERCOT: (1) to resume using the GRR Test on an interim basis for considering the consumer benefits of transmission, and (2) to propose a congestion cost savings test that best fits ERCOT's market to use on a longer-term ongoing basis.

The amended Rule indicates that any consumer benefits test is to be used as a supplement to the Production Cost Savings Test. This means that if a transmission project produces sufficient production cost savings (compared to the cost of the project), that line could be recommended for approval regardless of its potential consumer benefits test results. However, if a line's production cost benefits are positive but not large enough to merit project approval, but the line provides sufficiently large consumer benefits, the project may be recommended as economic based on the consumer benefits test results.

In response to the amended rule, ERCOT is utilizing the GRR Test on an interim basis starting in 2023. Additionally, ERCOT engaged E3 as its consultant to identify a set of viable options for ERCOT to use as a congestion cost savings test and recommend which option E3 believes is best suited for ERCOT.

[2] Transmission congestion is described in more detail in section 4.1 of this report. Transmission congestion can affect locational prices and thereby result in a cost that load entities pay the market for energy beyond the amount that the market compensates generating resources for their output. This difference is termed in this report as "congestion cost" or "congestion rent". ISOs typically allocate out the annual congestion rent collected and assign it among market participants. This returned amount of congestion cost to market participants represents "congestion revenue" that those participants receive. In most cases the total congestion revenue will equal or be near the congestion cost in the system for the year, so these terms are both used in this report.

E3 worked closely with ERCOT staff to perform this review. The details of the study approach and resulting recommendations are discussed in the following sections. E3's scope in this study was specifically focused on determining and recommending the appropriate calculation approach for a consumer benefits test. Many other aspects of the broader transmission evaluation study framework may affect whether a project is recommended for approval—for example, certain regions evaluate transmission projects by considering multiple value streams in addition to energy production cost or market price impact. The intent of this current work, however, is to be specific in identifying a viable consumer benefits test that could be approved and utilized promptly in an upcoming study cycle for ERCOT.

2.2 Study Approach

E3 assessed potential consumer benefits test options for ERCOT transmission evaluations by performing four sequential tasks:

- **Compile options**: E3 researched economic transmission evaluation approaches throughout North America, as well as Australia and Ireland, and discussed these approaches with planners in those jurisdictions to identify the range of options currently used for evaluating the economic benefits of transmission.
- **Analyze & compare options**: E3 categorized the options identified in the survey and compared the key aspects and implications of each option.
- **Assess applicability to ERCOT**: E3 identified the ways that each option would or would not fit with the ERCOT market rules and structure.
- **Recommend best option for ERCOT**: After comparing each option against key criteria, E3 recommended the best option for implementation.

The following sections describe the details of E3's work in each of these tasks.

3 Compiling Options: Jurisdictional Survey Overview

3.1 Summary of Jurisdictions Surveyed

E3 reviewed transmission planning documents and interviewed planners and regulators in ten jurisdictions. In addition to ERCOT, this evaluation included all six of the other Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in the US: PJM Interconnection, New York ISO (NYISO), ISO New England (ISO-NE), Midcontinent ISO (MISO), Southwest Power Pool (SPP), and California ISO (CAISO).

Additionally, E3 selected three international markets to also evaluate for providing a broader base of potential perspectives and approaches:

- The Alberta Electric System Operator (AESO) because Alberta is the only other market in North America, other than ERCOT, which has an Energy-Only market for electric power. All other North American markets include some form of capacity market or mandatory resource adequacy procurement for generation capacity;
- The Australia Energy Market Operator (AEMO) due to similarities with ERCOT in its historical use of energy-only power markets, as well as its increasing level of renewable buildout; and
- EirGrid in Ireland, which like ERCOT has a high level of wind build out and also has limited DC transmission ties to other regions.

These markets are shown with key characteristics in the maps below.[3] These markets span a wide range of features across a number of different dimensions including:

- **System size**: from 12 GW peak load in AESO up to 128 GW in PJM;
- **Wind and solar buildout**: from 4% wind buildout in ISO-NE up to 34% in EirGrid, and from <1% solar buildout in SPP and EirGrid to 20% solar in CAISO;
- **System density:** as highlighted by the varying miles of transmission lines within each market;
- **Market design features:** including use of zonal or nodal pricing for energy markets, with wholesale and/or retail deregulation, and different levels of utility ownership of the generation fleet.

[3] Details summarized for each market are based on information from reports collected from in June-July 2023; specific values for certain markets is changing rapidly and may have increased by the time of this reports' publication.

Figure 3-1: Jurisdictions Surveyed in North America

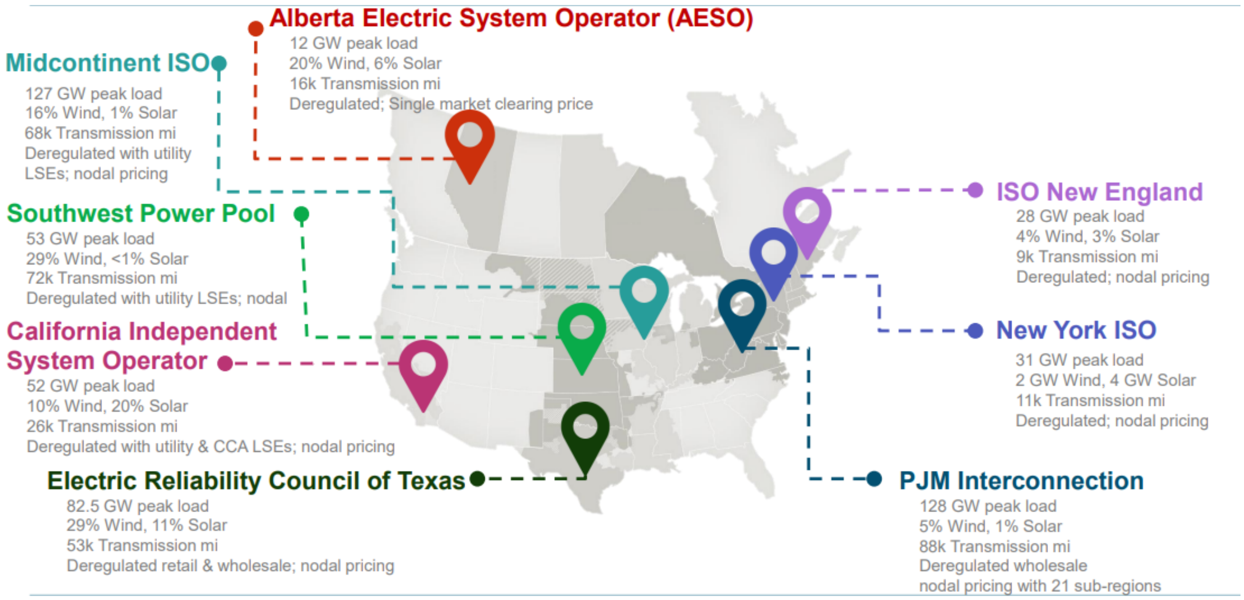


Figure 3-2: Additional Jurisdictions Surveyed

3.2 Commonalities and Variations in Economic Transmission Planning Approaches

Nearly all regions reviewed share a similar core framework for evaluating whether a transmission project is economic,[4] but these regions exhibit significant variations in details of how this framework is applied. The consistent core framework has the following key steps:

1. **Quantify the projected economic benefits of adding the transmission project to the system:**
    a. Use a production cost simulation model case to simulate system dispatch between two cases: (i) a base case without the proposed project versus (ii) a project case which adds the proposed transmission project to the base system;
    b. Use the change in results between the two simulation cases to calculate a defined economic benefit metric, with that change attributed to adding the project;
    c. Calculate any additional types of benefits of the transmission project not included in the production cost simulation test of 1a.
2. **Compare the projected benefits to the projected cost of the project:**
    a. Convert either project cost, or the projected benefits, to a similar time period or duration for comparison;
    b. Calculate a benefit to cost ratio of the project by dividing the converted benefits by the costs of the project;
3. **Comparing the project benefit to cost ratio to a defined threshold which the region has selected to use for determining whether a project is sufficiently beneficial for approval or further consideration.**

Variation in how this framework applied occurs at different steps in the process. This variation includes:

- **How the congestion-driven economic benefit metric (or test) is calculated using the production cost simulation outputs** (*Step 1b*): Different regions choose different approaches for calculating economic benefits, including whether or not it is appropriate for their region to include changes to generator cost, generator revenue, and transmission congestion revenue, whether to evaluate outputs from a societal or consumer-only perspective, as well as whether to evaluate results at a system wide or zonal/sub-regional level. ***For ERCOT, this decision is the central focus of the current analysis and will be the primary matter discussed in the remainder of this report.***

- **Whether other types of economic benefits are included beyond the congestion-driven energy price/cost impact** (*Step 1c*): In some regions, additional types of benefits are sometimes added to the economic benefit results of the production cost simulation model. For different jurisdictions, these may include, but are not limited to:

[4] The primary exception to this core is the AESO. In Alberta, the province has a policy to seek to eliminate transmission congestion. The intent of this policy is to promoting competition among resources participating in the market. In pursuit of this policy, the objective is not defined as an economic test, so a projected benefit is not compared to the project's cost for determining approval; rather, the project is evaluated directly for its ability to minimize congestion compared to other options.

- Capacity value: The project's impact on generator capacity cost (in regions that have capacity markets or where transmissions buildouts may directly affect the amount of generation that is needed);
- Savings from deferral of alternative reliability-driven project: Ability of the project to defer the need for other alternative transmission projects that would be required for maintaining reliability in a future year;
- Resilience value: Improvement to expected reliability or resilience of the system, particularly during extreme conditions;
- Resource procurement value: The project may enable market participants to develop new resources or loads to procure additional energy from other sources that would not have otherwise been accessible without the transmission project. To the extent that resources procured over a new transmission project have attributes that are preferred by the customers or that support achieving of state policy goals (such as renewable portfolio standard (RPS) targets), this additional value may be additive to the value of the line;
- Competitive value*:* The additional transmission line may increase the expected competitiveness in bidding between market participants within a particular sub-region, or between resources in those sub-regions, reducing costs to loads and potentially improving efficiency;

In some cases, additional types of benefits are qualitatively assessed, or used for information purposes to indicate broader impacts of a line, while in other regions, some of these additional benefits are directly incorporated into the benefit to cost calculation. *In the ERCOT market, other types of benefits are not currently considered.*

- **How projected benefits are converted to compare to project costs** (*Step 2a*): The vast majority of costs for a transmission project are capital costs incurred as the project is being constructed, but potential impacts of the project's active presence on the system occurs over the project life which could range from 30 to 50+ years. Study time and data limitation make it prohibitively challenging to directly model system operations in all years of the project life, and later years have greater uncertainty as well as reduced time-value due to discounting and inflation adjustments. Some regions address this issue by identifying the benefits in 1-3 years of simulations and then using interpolation and extrapolation to other years of the project life and then converting those savings (as well as expected operating and maintenance costs of the transmission project) to a present value which is then compared to upfront project cost. Other jurisdictions take the cost of the line in a certain year, or they convert the present value of the total lifetime line cost to an annual "levelized" metric, which they then compare to an annual benefit value calculated. In either approach, the region must select financial assumptions to appropriately compare costs or benefits that occur in different years. *For the 2023 RTP study cycle, ERCOT's current approach compares the production savings from a proposed project levelized based on two study years of results (2025 and 2028) to the first-year annual revenue requirement of the proposed project, which ERCOT analysis represents at 13.2% of the project total capital cost. The ERCOT approach used for 2023 also compares the project's consumer benefits (based on the generator revenue reduction test results levelized over these two study* *years) to average of the annual revenue requirement for the first three years of the proposed project, which ERCOT represents at 12.9% of the projects total capital cost.*[5]

- **How the threshold level is set for determining whether a benefit to cost ratio supports or does not support project approval or further development** *(Step 3)*: Most regions typically compare a benefit-to-cost ratio to a threshold of 1.0 for determining whether a project is economic. However, in certain areas, somewhat higher thresholds may be used – particularly if benefits are viewed as less certain than the cost of a project, or if additional benefits are included but are not certain to be entirely mutually exclusive. *ERCOT compares the levelized benefits with the first-year revenue requirement or the average revenue requirement of the first 3 years for the transmission project and supports project in which these benefits are greater than or equal to the first-year revenue requirement or the average of the first 3 years revenue requirements.*

- **How the production simulation cases are developed** *(step 1a)***.** Different regions use a wide range of techniques for conducting simulation cases. Certain variations include:
  - Production cost simulation software: Different regions use different models including MAPS by GE, GridView or Promod by Hitachi, PLEXOS or AURORA by Energy Exemplar, Power System Optimizer (PSO) by Enelytics, or other models including those developed specifically for or by the system operator. Each of these models have some common details of different settings and details that can affect the results of particular cases. *ERCOT currently uses the UPLAN model by LCG Consulting.*
  - Zonal or nodal model topology: Transmission economics can be determined using models that simulate loads and resources at each node of the system (sometimes with aggregation) or at a zonal level with key interfaces that cause congestion determining the boundaries of different nodes. *ERCOT's UPLAN model is run in a nodal framework.*
  - Selection of study years to test: System operators study different test years or groups of test years for identifying the potential impact of a new line on the system. It is rare to model every study year and often a better use of analytical resources would be to instead model a subset of years over more scenarios. In markets with an evolving mix of resources and growing loads, it can be useful to model 2 or more years to identify how changing system characteristics may affect the value of the new projects. Nearer term study years may have more certainty regarding generation and load, while further out study years may require more input assumptions but also identify value that could apply over many years of the projects later in-service life. *ERCOT currently models a second year and fourth year study case (e.g., the 2023 study cycle evaluated the years 2025 and 2028).*
  - Determination of load, generation, and existing transmission assumptions in the base case for the study year: System operators must make assumptions on the growth and hourly shape of loads in the planning year of the study to test. Different system operators utilize a range of internal and external data sources to develop this

[5] See ERCOT 2023 Regional Transmission Plan Report, section 4.1. These economic tests are based on Amended PUCT Substantive Rules 5.101(b)(3)(A) (https://www.ercot.com/files/docs/2023/12/22/2023_Regional_Transmission_Plan_Report_Public.zip)

information. Typically, generation information is based on a portion of projects under construction or in advanced stages in the interconnection queue. For longer-term study years, certain ISOs also use assumptions or long-term capacity expansion simulation models to add more generation in response to growing loads, to replace retiring units, or to fulfill jurisdictional policy targets for generation of different types. *For its base study case, ERCOT utilizes its own internal load growth projection. includes new generation projects in the interconnection queue that have signed Interconnection Agreements and have met other siting requirements and includes existing and previously approved transmission projects.*

- Individual vs. Portfolio Evaluation of Projects: Some regions model single projects independently while other areas model a collection of projects together. To the extent that different projects provide similar advantages, adding more projects may reduce the average value per MW as there may be diminishing marginal savings from transmission upgrades. In other cases, two or more projects may complement each other (e.g., if one project upgrades transmission facilities downstream of a new major line, which could alleviate the potential that downstream facilities become a new constraint that limits the new line's value). *ERCOT will typically first study individual projects, but its system planners can selectively choose to study multiple projects or group projects together if they expect that could unlock more value or overcome limitations.*
- Modeling contingency-driven constraints and lower voltage system interactions in a simulation: The amount of power that can flow over lines on a transmission system depends not just on the rating of that line, but also how much flow the system could handle under contingency conditions when that line or another unexpectedly goes out of service. Simulation tools can incorporate these types of contingency impacts by adding additional constraints on the system to limit flow to levels that are prepared for the contingency, even if the contingency is never realized. Different study regions model contingencies to greater or lesser degrees of detail, particularly on lower voltage facilities which may have lower degrees of data verifications or may present challenges that the system operator assumes will be addressed through some subsequent action(s). *ERCOT currently models constraints for system contingencies in a high degree of detail in its UPLAN cases.*
- Sensitivity analysis: Each simulation case typically models all hours of a single study year, but reflects one set of assumptions for load growth, weather patterns during that year, and resource additions and retirements. In some regions where these inputs have a higher degree of uncertainty, transmission planners model additional sensitivity cases to identify whether the economic benefits are strongly affected by particular input assumptions. *ERCOT currently begins studying transmission projects in each study cycle with a base case set of input conditions, but ERCOT engineers may choose to simulate additional sensitivity cases for projects that have benefits that are near but not above the target threshold.*

The remainder of this report focuses on the determination of an economic benefit test for evaluating consumer savings in ERCOT (Step 1b).

4 Key Findings

As noted in the prior chapter, E3's research and survey identified a range of approaches for how the economic benefit test is calculated based on the outputs of the production cost simulation model cases. Using this information, E3:

1. Compared the tests being used and highlighted the key distinctions among them;
2. Evaluated how the tests used in particular jurisdictions fit well with the distinct features of the systems where they are applied;
3. Identified distinct features of the ERCOT market that are important criteria for evaluating how well a particular consumer benefits test would fit;
4. Evaluated how well each option would fit with ERCOT market; and finally,
5. Recommended the most appropriate consumer benefits test option for ERCOT to use.

4.1 Background: Locational Marginal Price (LMP) and Transmission Congestion

To understand different consumer costs test options, it is useful to review the related concepts of locational marginal prices (LMPs) and transmission congestion. The Locational Marginal Price, or LMP, is the cost to serve the next increment of load at an electrical bus location. and is based on the sum of the marginal cost of energy for the system, plus marginal cost of congestion for the location, plus the marginal cost of real power losses for the location. This section provides background on these concepts which are relevant to understanding cost tests calculations and defines some of the terms used subsequently.

LMPs are the basis for generation and load settlement: In the ERCOT market, generators are paid for their energy production on a $ per MWh basis based on their LMP. At the wholesale level, system level loads customers are charged for the energy they consume based on a load area price, which is essentially an average of the LMPs at all nodes within a certain sub-area of the ERCOT footprint, weighted by the MWh of energy consumed at that location. When summed for the full system, this is the mathematical equivalent of charging loads at their nodal LMP.

Transmission congestion and impact on LMPs at different nodes: "Transmission congestion" is a term used to describe the presence of one or more operational limits of the transmission system which require the system operator to dispatch generation in a manner that has a higher cost than the underlying supply of resources would permit in the absence of those limits.

If there is no economic congestion in an entire market footprint for a certain hour (and no losses), then the LMP would be the same for all locations. In this situation the system operator can optimally dispatch all generators as though they are all part of a single "supply stack" without regard to location, starting with the generator with the lowest offer price, then the generator with the next lowest offer price, and moving up until the supply offers selected meet the demand of the system for that hour. The market price in that hour would be the marginal energy cost of the system, which is based on the offer price of the last generator that was selected to be able to meet that hour's system-wide demand. That generator will have the highest price offer among resources selected for dispatch. If there is no congestion, this price would be the LMP for all locations in the system and used to compensate all generators producing power and to charge all loads consuming power.

If instead, there is congestion on one or more transmission facilities in that hour, then the system operator cannot simply consider only a resource's offer price when selecting it for dispatch, but also the location of the generator. To avoid sending more power over a certain congested transmission facility than would be allowed for operating the system reliably, the system operator reduces dispatch allocated to a low-cost generator that would increase flow on that line, and instead selects to dispatch more energy on a generator (that may have a higher cost) in a location that has neutral or positive impact on flow over the congested transmission facility.

Congestion impact on LMPs - two zone example: In a simplified system with only two locations or zones, this dynamic can be described as reducing dispatch on generators "upstream" of a constraint because their output would need to flow over the constrained line to serve loads and instead increasing output on generators "downstream" of the constraint and closer to the load. This dispatch change enables the line flow to stay within acceptable limits. The LMP in the zone "downstream" of the constraint will be based on the marginal cost of the higher cost "local" generator needed to serve the load. This price will be used to compensate generators and charge loads located in that zone. The LMP in the zone "upstream" of the constraint will be based on the marginal price of the last (highest cost) generator selected for dispatch from that zone before the transmission limit is reached. Thus, the system will have a different price for each zone.

Congestion impact on LMPs – calculation in a network system: In actual practice, transmission systems are complex networks with a wide range of types of constraints which can lead to congestion at multiple locations on the system in certain hours. In addition, the power system experiences real power losses in which some power is lost due to friction when sending energy over transmission lines. These losses will also have some impact on LMPs, though typically the effect is less than the impact of congestion on prices. The LMP at any given location will reflect the product of:

1. The Generation Shift Factor (GSF) which measures the change in MW of line flow on a congested transmission element in response to as a result of an incremental 1 MW of load at an individual node in the system, *times*
2. The marginal value of congestion on that transmission element those elements. The marginal value of congestion represents how much lower the systemwide cost of dispatching generation could be if 1 MW more were enabled to flow over those congested transmission line(s).

The product of these two values can then be summed for all congested transmission elements in the system to produce the total marginal congestion cost component of the LMP for an individual node. This calculation can result in hundreds of different LMP values for different nodes in the system at a given dispatch interval when there is congestion on at least one line in the system.

Overall, since power flows from generators to loads, it is typical that nodes in areas with more load than generation will be downstream of the transmission constraints, and thus have higher LMPs. By contrast, nodes in areas with significant generator output and less load will often be upstream of congestion and have lower LMPs than the system average. In these hours, the total dollar value amount that the system charges to loads (at load LMPs) will be greater than the value of the revenue the system pays generators (at generator LMPs).

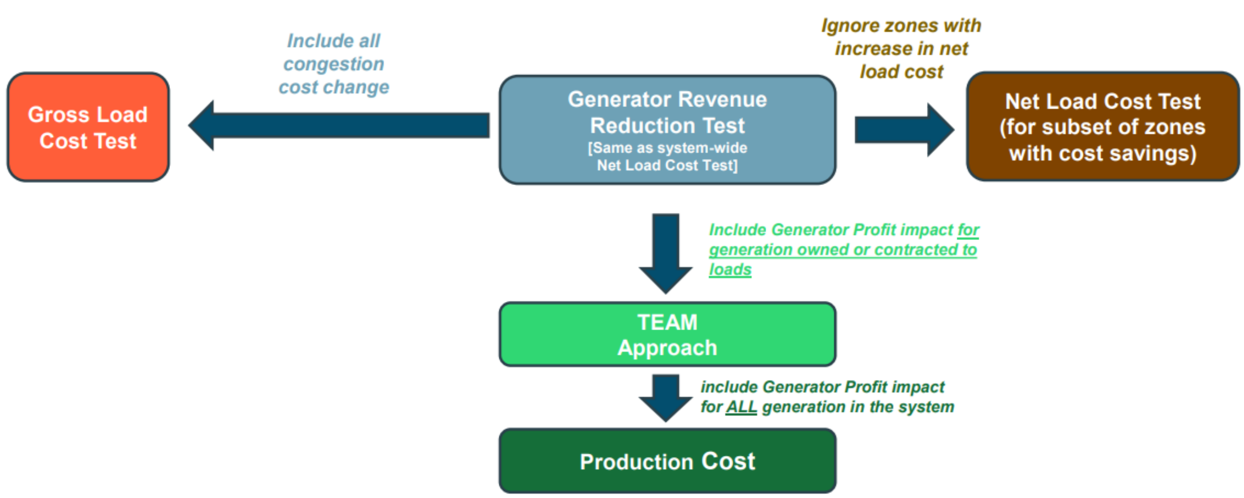
ISO/RTO treatment of congestion rent: The difference between the total generator revenue and load cost equals to the "total congestion value" on the system for that hour. This congestion value is also described as "congestion rent" because rent in economic terms represents an additional amount of money earned from a sale above the cost of producing the item sold. In this case, the ISO's payment to generators for producing energy is lower than the amount of money collected by the RTO in load payments (due to the impact of congestion on LMPs), with the difference representing the congestion rent.

Because most ISOs and RTOs are not-for-profit entities, they return this total congestion value to market participants through various mechanisms. The most common approach for allocating this congestion value is to first auction off "congestion revenue rights" (CRRs) or "financial transmission rights" (FTRs) or "auction revenue right" (ARRs). These are financial instruments that an entity (a load, a generator, or a third party) can purchase that entitle the purchaser to receive the difference in LMP between a selected pair of nodes over a defined period (typically a month or year). In addition to giving an allocation of the resulting rent that occurs on the system to loads or other entities, the ISO will also allocate CRR or FTR auction proceeds among market participants or use it to reduce the net transmission cost that must be charged to those participants to fund the ISO's operations and to compensate the transmission investments it oversees. These auction proceeds are assigned differently in different ISOs and can also be greater than or less than the resulting congestion rent depending on how aggressively auction participants bid for the CRRs/FTRs.

4.2 Comparison of Consumer Benefits Test Options

This section describes the consumer benefits tests currently in use in different jurisdictions and compares key features of these tests. All five tests being utilized are shown in Figure 4-1 below with key characteristics that distinguish them from other tests. We discuss each test in more detail below.

Figure 4-1: Consumer Benefit Test Options



4.2.1 System-Wide Generator Revenue Reduction Test

A System-Wide Generator Revenue Reduction (GRR) Test measures the change in the total payment the system makes to generators for their energy output. This test is shown in blue in the top center of Figure 4-1.

Calculation: For each generator in each hour, the GRR test first calculates generator revenue as the product of:

*(the energy output of the generator in that hour) * (the generator's hourly locational marginal price, LMP)*

This hourly result is then summed for all hours of the study year for all generators in the market footprint to produce system-wide annual generator revenue for a case. The GRR test then calculates consumer benefit as the change in system-wide annual generator revenue between the base case and the project case.

Implications for Consumer Benefits of a new Transmission Project: A transmission project will produce consumer savings under the GRR test if it reduces congestion by enabling more generation output to occur at locations that have lower prices and marginal costs and less generation output to be needed at locations with higher prices. These types of substitutions will likely lower both production cost and generator revenue. The transmission project may also produce additional savings by reducing the prices at locations where generators produce power. By enabling the system operator to avoid dispatching a more expensive generator in the higher-priced location, the marginal cost (and LMP) at that location will be reduced. Thus, this approach assumes that if a transmission line results in generators in the system footprint being paid less in total, then that reduction in generator payment or revenue represents the benefit of the new line to consumers.

By using the generator locational price, this approach implicitly assumes that all transmission congestion value is returned to load customers, typically through the auction of congestion revenue rights. This means that the test assumes that load customers are fully "hedged" to the direct cost of congestion, so the total cost loads (net of any payments they receive from congestion revenue rights) will not change if congestion increases or decreases. For example, if a new transmission project reduces the total congestion on the system the price at load locations is expected to be lower so loads will pay less for that energy, but the payments the loads receive back from congestion revenue rights (or auction proceeds) will also go down. This approach assumes that these payments will fully offset the impact of congestion cost to loads, so a new transmission project will not have an impact on consumer savings beyond the amount that it reduces revenue paid to generators.

The GRR test can also be described as a "Net Load Cost Test," which reflects the fact that impact to load are calculated as net of changes in congestion cost and thus assumed payments to loads from congestion revenue rights.

Jurisdictions using this test: The GRR test was used as a consumer benefits test by ERCOT from 2006 to 2012 and is being applied on interim basis since 2023.

4.2.2 System-Wide Gross Load Cost (GLC) Test

A System-Wide Gross Load Cost (GLC) Test measures the change in total wholesale energy cost charged to consumers (loads) in the system. This test is shown in the top left of Figure 4-1.

Calculation: For each load in each hour, the System-Wide GLC Test first calculates the load payment as the product of:

*(the energy consumed within each load area in that hour) * (the hourly average LMP for all nodes in that load area's hourly, weighted by the load at each node)*

This hourly result is then summed for all hours of the study year for all load areas in the market footprint to produce system-Wide GLC in a case. The System-Wide GLC Test then calculates consumer benefit as the change in System-Wide Gross Load Cost between the base case and the project case.

Implications for Consumer Benefits of a new Transmission Project: A transmission project will produce consumer savings under the System-Wide GLC Test if it reduces the LMPs at load locations. If the project enables more generation to serve load from lower cost areas, and that change reduces the amount of higher cost generation that must be dispatched near loads, then the marginal price near load locations will decrease, producing a lower Gross Load Cost.

Comparison to Generator Revenue Reduction (GRR) Test: The System-Wide GLC Test and the GRR Test are similar in many ways, in that they measure either the total amount of energy that a system produced or consumes, valuated at the location of the production or demand. The key difference between the two tests is how congestion cost is treated. Thus, the difference in the quantitative results of the two tests will represent the change in "congestion cost" in the system from adding a new transmission project. If a new project reduces congestion in a system, then the resulting benefit from a System-Wide GLC Test will be larger than that of a GRR Test, with the difference equal to the amount that congestion has changed due to the new project. That is, the System-Wide GRR (or net load cost test) can be calculated by first calculating the gross load cost impact and then subtracting the sum of congestion cost change. The cost of real power losses creates a small additional difference between the GRR and the System-Wide GLC Test, but this impact is typically significantly smaller than the impact of congestion.

The system-wide gross load cost will be higher than generator revenue when there is transmission congestion because on average that congestion will cause prices to be higher at load locations than generator locations. If the amount of that congestion is reduced, then that may reduce prices at load locations on average, which will contribute to savings under the System-Wide GLC Test. Reductions in congestion can sometimes increase the price at generator locations, which can result in increases in generator revenue.

As noted above, the GRR Test (also termed a "net load cost test") implicitly assumes that all transmission congestion cost is returned back to power consumers, so reducing congestion is not a source of potential consumer benefit under the GRR Test. The System-Wide GLC Test, by contrast does not subtract or "net off" the impact of any congestion payments back to loads. Instead, the System-Wide GLC Test directly calculates the total cost of energy paid at the load locations.

Jurisdictions using this test: The NYISO uses a GLC Test to provide a broader view of the impact of a transmission line on load customers in its market. In NYISO, this test is used for information purposes as a supplement to a Production Cost Savings Test, which is the key metric used there to evaluate whether a transmission project is economically beneficial compared to its cost.

4.2.3 Zonal Net Load Cost Test

Similar to the GRR (also termed a System-wide Net Load Cost Test), a Zonal Net Load Cost Test calculates the cost to loads, net of any congestion payments, but this test performs this evaluation looking only at one or more selected zones rather than the entire broader system. By looking at a zonal, rather than a system-wide level, the zonal Net Load Cost Test can identify transmission projects that create benefits for a subset of consumers, even if the line also causes an increase in cost to consumers in another location. This test is shown in the upper right of Figure 4-1.

Calculation: For each zone of study in each hour, the zonal Net Load Cost Test can be calculated as:

*(the energy consumed within each load area in that hour) * (the hourly average LMP for all nodes in that load area's hourly, weighted by the load at each node) MINUS (congestion revenue accruing to load or transmission in that zone[6])*

Then the zonal net load cost savings from a transmission project can be aggregated by adding up the test result <u>for all zones that have positive zonal net load cost savings</u> and using zero for the impact in any zones with net load cost increases.

Implications for Consumer Benefits of a new Transmission Project: A transmission project will produce consumer savings under Zonal Net Load Cost Test if – in one or more zones evaluated - it reduces load payments (at the locational prices of the loads) by more than any change in transmission revenue. If loads in any of the zones of the system benefit, those zonal benefits will be considered as the savings produced by the line, regardless of whether there are other zones that have net load cost increases.

Comparison to System-Wide Generator Revenue Reduction Test: The Zonal Net Load Cost Test differs in geographic scope from the System-Wide GRR. If adding a transmission project causes loads in some zones to have net load cost reductions, these increases will be considered in the System-Wide GRR Test, but will be excluded from the Zonal Net Load Cost Test. Thus, a project with different impacts in different zones of a system will have higher benefits under a Zonal Net Load Cost Test than in the System-Wide GRR Test. If adding the transmission project does not cause increases to net load costs in any zone studied (i.e., all zones have net load cost savings or no change), then the Zonal Net Load Cost Test and the Generator Revenue Reduction Test will produce the same value for the project.

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[6] Transmission congestion rent can be attributed to specific transmission elements or binding constraints on the system. The market operator can use this information to assign the revenue to particular transmission system owner of those elements (in some regions, these transmission owners are also load serving entities), or the ISO can assign the revenue among loads or other market participants on a system wide or sub-regional basis or based on each entity's purchase of CRRs/FTRs in an auction. If a portion of these revenues can be associated with consumers in a particular zone or sub-area of the system, this revenue can be subtracted from the load cost charged to those consumers.

Jurisdictions using this test: This test is utilized in PJM. For projects on lower voltage (up to single circuit 345 kV), the Zonal Net Load Cost Test is the key metric for valuing the consumer benefits of the project. Larger regional transmission projects (double circuit 345 kV and above) are evaluated based on a combination of 50% of their Zonal Net Load Cost impact and 50% of their system-wide production cost impact.

4.2.4 Transmission Economic Assessment Methodology (TEAM) Test

The Transmission Economic Assessment Methodology (or TEAM) Test seeks to evaluate consumer benefits of transmission lines with an additional consideration of the impact of the transmission on profits (also termed "net margin") on generation resources that are owned or contracted on a long-term basis to load customers. The TEAM Test evaluates the impact of transmission on load costs net of congestion revenue impact (similar to the GRR Test) but then also identifies a subset of generators that are owned or contracted to loads and subtracts any reduction in profits on those resources from the GRR result. Generators that are partially owned or that have a share of the unit under contract can apply an ownership percentage value (from 0 to 100%) to indicate the portion of revenues and dispatch cost for the plant should be attributed to load serving entities.

This test assumes that loads entities are "partially hedged" with respect to wholesale power prices by receiving from the output of certain generators in the system. In the absence of congestion, if market prices go up then the load serving entity will have higher load payments, but also more generator revenue. Congestion may make prices to differ at load nodes versus contracted generator locations (and create a difference in the impact of price changes for an entity's loads versus its generator, but nominated paths for congestion revenue rights that accrue to load which can also hedge that congestion impact).

This approach is shown below the GRR Test in Figure 4-1 because it also considers the net cost impact to loads (net of congestion revenue) but also adds an additional component to account for the impact of a line on profits of generators owned or contracted to load entities.

Calculation: The TEAM benefit calculation has three major components:

(Gross Load Payment)

minus (congestion revenue for load serving entities)

minus (Generator Profit on units owned or contracted to loads)

where:
*Gross Load Payment = (hourly load MWh by node) * (hourly nodal LMP), summed annually for all load*

*Congestion revenue for load serving entities = (hourly MWh flow on congested transmission facilities) * (LMP difference between nodes at either end of the facility) for all facilities that have been nominated to have congestion revenue applied to loads, and 0 otherwise, and*

*Generator profits on units owned or contracted to loads = (Hourly Generator output * hourly generator LMP) minus hourly generator production cost, for all generation facilities owned by or with long-term contracts to loads, and 0 otherwise*

It is important to note two factors in determining which generators to include as owned or contracted to load serving entities:

- Generating facilities' contracts with loads must be sufficiently long-term to be considered in this calculation, because if a line increases the market revenue on a given generator and the contract is not long-term, then the change in market prices may cause the generator to subsequently re-contract at a higher price closer to the market value, which would create a similar dynamic for consumer benefits as if the unit were not contracted; and

- The generation facility must be owned or contracted to the entity serving loads in a way in which the profits from the generator will accrue to the load customers, reducing the final cost they need to pay for energy; if instead the generator is owned by an affiliate that does not have revenue come back to the load entity, then the generator's profit would not be appropriate to consider as a factor in the final cost to consumers.

Implications for Consumer Benefits of a new Transmission Project: A new transmission project may produce consumer benefits in a number of ways. Like the GRR, if the transmission leads to a reduction in prices at load nodes (and thus a lower total load payment), this will result in a benefit to consumers, but this benefit can be partially offset by reduced revenue to the load/energy consumer (a) if the transmission project reduces profits on generators owned or contracted to loads, or (b) if the transmission project reduces congestion revenue that accrues on transmission paths nominated to be paid to load.

Comparison to System-Wide Generator Revenue Reduction (GRR) Test: The TEAM calculation starts with the GRR calculation but expands this in two potential ways:
(a) TEAM adds in the impact of change in generator profits for the units owned and contracted to loads. If a transmission project reduces the congestion in a system this may increase dispatch and prices paid to generators upstream of the constraint, and if this resulting increase in generator profit is on units owned or contracted to load entities that profit is added to the consumer benefit of the line. Alternatively a transmission project reduces prices (and dispatch) in other locations, it may reduce profits for other utility-owned generators in which case this generator component will reduce the consumer benefit value calculated; and
(b) TEAM may incorporate and subtract congestion revenue related to a subset of transmission lines that are assumed to be owned or contracted to consumer entities; unlike the GRR, this may not include all transmission facilities in the system so TEAM may be partially between the results of the GRR and Gross Load Cost Test with respect to treatment of congestion revenue.

Jurisdictions using this test: This test was developed by California ISO in conjunction with an advisory group. It is currently used to evaluate whether a new project in California ISO is economic to build.

4.2.5 Production Cost Savings Test (and Adjusted Production Cost Savings Test)

The Production Cost Savings Test is the most commonly utilized test for evaluating the economics of a new transmission project. The Production Cost Savings Test is typically considered to be a "societal" cost test because it seeks to captures the total cost impact of a transmission line on all groups of entities participating in the market: energy consumers (loads), energy producers (generators), and transmission ownership/rights holders. However, in a power market where most generation is owned or contracted to loads, and most congestion revenue is returned to load serving entities, this test would also represent the consumer cost impact.

Production Cost Savings Tests are sometimes titled as Adjusted Production Cost Savings (APC) tests. The most common adjustment applied in this circumstance is the revenue for energy exports out of the system and cost of energy imports into the system.

Calculation: In a closed power system (no material imports or exports), the Production Cost Savings Test can simply be calculated as:

The total variable production cost result of a base case MINUS total variable production cost in a project case with the new transmission added.

The largest production cost in most systems is the fuel cost, followed by variable operations and maintenance (O&M) charges that scale with the output of a plant, as well as additional startup costs, and potential emissions costs if the jurisdiction imposes a price on one or more types of emissions.

Some jurisdictions include in production cost the lost production tax credits (PTCs) due to curtailment of output from generators receiving those credits, while other jurisdictions exclude this factor.

Capital costs and fixed O&M are typically excluded from a Production Cost Savings Test because they are assumed to remain unchanged between a base case and a project test case, because the project case is seeking to isolate the impact of the new transmission project from other potential changes to the system (such as additional generation build).

If the power market imports purchased power from an outside area or makes export sales to another territory, then the revenue or cost from those external transactions can be added for each case as an adjustment to production cost.

Finally, if a production cost case shows some loss of load or a violations of reliability constraints such as a shortage of ancillary services in one case, that impact can be assigned a per MWh cost and added to the total adjusted production cost of the case. This is especially important to do for losses of load so that a case does not appear to have a lower production cost simply because it is not serving as much load as the base case.

Implications for Consumer (or Societal) Economic Benefits of a new Transmission Project: A transmission project will have production cost savings if the project enables less energy to be produced on higher cost generators in the system and instead have more of that energy generated by lower cost generators located in other parts of the system that would not have been able to generate as much energy due to transmission constraints if the new transmission project were not in place.

Energy may be produced at lower cost due to (a) different fuel types, including zero cost generation, (b) lower locational price of fuel supply, or (c) lower heat rates or variable O&M on some units than others. Additionally, if a project reduces the system wide real power losses, that reduction would also create production cost savings by reducing the total MWh of energy needed to serve load.

Comparison to System-Wide Generator Revenue Reduction (GRR) Test: As noted above, Production Cost Savings Tests are often described as a "societal benefits test" which is a different category of economic benefits evaluation than consumer benefits tests, because a societal test takes a wider perspective on *who* is included as a beneficiary in the calculations.

The Production Cost Test, however, could also reflect the impact on consumer benefits in a power market where most generation is owned or contracted to loads, and most congestion revenue is returned to load serving entities. In this case, the test can be a continuation of the TEAM Test- except one in which all generation profit and congestion revenue accrues to load serving entities, rather than only profits from a subset of owned and contracted generators. This would be appropriate for capturing consumer benefits in a market where all or nearly all utilities are vertically integrated or have long-term contracts with nearly all generators in the system.

In all cases, the gross revenues that generators receive plus the congestion revenue in the system will equal the total gross load payment. Therefore, if a test evaluates the impact on all generators and loads together, the payments from loads and to generators for energy (or to congestion revenue rights holders) will represent a transfer payment that cancels out. The remaining item will be the cost of production on the generating units, which is the same as the Production Cost Savings Test.

Jurisdictions using this test: This is the most widely used test for calculating the economic benefits of transmission, including in ERCOT (in conjunction with the GRR), MISO, SPP, NYISO, ISO-NE, AESO, AEMO in Australia, and EirGrid in Ireland. It is also used for informational purposes in CAISO and used in PJM to contribute 50% of the benefit value for high voltage projects above single circuit 345 kV. Many of these markets do not specify whether their reason for selecting the Production Cost Savings Test is because (a) the test represents a societal benefits economic test for the whole system or (b) a consumer benefits test with generation assumed largely contracted to consumers. Certain markets such as SPP, however, exhibit a higher degree of integration between generators and loads due to high levels of generation ownership or long-term contracts by load serving entities, so it is reasonable to think of this as both a societal and a consumer benefits test perspective in those cases.

4.2.6 Change in System-Wide Total Congestion Cost (not shown on diagram)

System-wide total congestion costs measure the sum of the cost of congestion within a power market. Total congestion cost is not shown in Figure 4-1because it is not typically presented as a type of consumer benefit test (or societal benefit test).

Calculation: System wide congestion cost change can be calculated as:

Total System-wide congestion cost in the Base Case MINUS
Total System-wide congestion cost in the case with the transmission project added.

In each case the system wide congestion cost will equal the difference in total gross load cost (load MWh times load weighted nodal market price) minus total gross generator revenue (the sum of individual generator output in MWh times generator-specific nodal market price). If there is only one congested transmission line, then the congestion cost will equal the MWh of energy flow on this line times the nodal price difference at either end of the line.

Implications for Consumer Benefits of a New Transmission Project: A transmission project will reduce system-wide congestion cost if it reduces the nodal price differences across the system by allowing more energy to flow from the locations of lower cost generators, which would lower the need to run more costly generators in locations closer to loads. The reduction (in a project case vs. base case) in LMP differences on nodes connected to a congested line times the flow on that line will be the congestion cost savings attributed to the project.

This test, however, is not applied directly as a consumer benefits test because the magnitude of its impact is not directly connected to the value that a new project may create in benefits for consumers. The actual impact on the total cost of energy consumption to consumers may be higher or lower than the congestion value. These differences can be illustrated by two examples:

i. If there is congestion on a transmission line going into the load area, the value of congestion will be based on the difference in locational price upstream and downstream of the constraint, multiplied by the flow on the line. The congestion on the line, however, may impact the prices that all loads pay (and that all generators are paid) inside the congested area. Therefore, if a constrained transmission line serves only a portion of the load in an area (and local generation serves the remainder), the impact on load costs may apply to a larger volume of total energy than solely the flow on the congested line. In these cases, the impact of adding a new transmission project that reduces this congestion may have larger benefits in terms of savings in load payments than the change in congestion cost estimates.
ii. Alternatively, in other areas, if a transmission line connects to generation that is far from loads, it may result in significant congestion that is primarily attributable by lower prices at the generator nodes. If the constrained generation is relatively small compared to the overall load of the system, however, the constraint may have a negligible impact on the prices that most loads pay. Therefore, adding a new transmission project to reduce congestion in this area may materially increase the revenue to the constrained generators but not change the cost that loads pay by as much as the change in congestion cost from adding the line.

Additionally, in some jurisdictions, load entities receive revenue back from the congestion on the system as a way to compensate them for providing transmission to the system. To the extent that congestion is returned, a reduction in congestion alone may be a neutral impact, rather than a savings, for load customers as a whole. In certain circumstances, it could even represent an increase in cost if prices at the locations of load customers do not go down in the same proportion. For individual load entities, lower congestion is likely a beneficial change as it reduces the uncertainty or risk related to individual transmission ties and the revenue returned which may be difficult to perfectly hedge an individual impact to consumers. The magnitude of that benefit to the full group of consumers as whole, however, is difficult to identify and not directly comparable to the cost of a new transmission project.

Comparison to Generator Revenue Reduction Test: A system-wide congestion cost test is similar to a GRR or Net Load Cost test, but (1) it omits the Gross Load Cost impact, and therefore only evaluate the change in congestion, and (2) a reduction in congestion cost is here shown as a type of savings, whereas in a GRR or Net Load Cost Test, a reduction in congestion reduces congestion revenue and therefore is an offset to consumer benefits (instead an increase in congestion results would represent savings).

Jurisdictions using this test: Many jurisdictions including ERCOT measure system-wide congestion cost, but none uses it as an economic benefits test that is evaluated compared to the cost of a line. Instead, this calculation is used informationally for prioritizing potential areas to address, but the final calculation is not directly linked to consumers benefits. A reduction in congestion may result in lower Gross Load Costs, or alternatively, an increase in Generator Revenue (prices at generator nodes), or a combination. Additionally, loads may be partially or fully hedged to congestion costs depending on the treatment of congestion revenue rights (also termed financial transmission rights).

4.3 Comparison of Consumer Benefits Tests and Regional Applications

4.3.1 Comparison of Consumer Benefits Tests

All consumer benefits tests discussed in the prior section can ultimately be compared by their treatment of 3 components of impact:

- Impact on Load Payments
- Impact on Generator Profit
- Impact on Congestion Cost

Table 4-1 below summarizes how these three components can be used to construct each of the tests. Some tests include the impact for all loads, generators, or transmission in the market, while other tests use a subset of one of the or more of these impact components.

Table 4-1: Impact Components of Consumer Benefits Tests

Consumer benefits test includes impact to:	Load Payment	Congestion Cost (Congestion Revenue);	Generator Profit
System Wide Gross Load Cost (GLC) Test	+ (All Load)	None	None
Generator Revenue Reduction (GRR) Test	+ (All Load)	- (All Congestion)	None
Zonal Net Load Cost Test	+ (Portion of Loads)	- (Portion of Congestion	None
TEAM Test	+ (All Load)	- (Congestion Revenue Rights for Load Entities)	- (Load Owned & Contracted Generators)
Production Cost Test	+ (All Load)	- (All Congestion)	- (All Generator Profit)
Congestion Cost Reduction	None	+ (All Congestion)	None

Load Payments (based on the hourly loads and nodal prices at load locations) should be evaluated for all of the system if new transmission costs are assigned throughout the system. If instead transmission costs can be allocated to a subset of those loads, then it can be useful to consider the impact to the subset of loads that would fund the upgrade.

Generator Profits (based on the hourly generator output and nodal prices at generator locations, less cost of generation) should only be considered in a consumer benefit test to the extent that generation is owned or under long-term contract to load serving entities.

Congestion Revenue / Congestion cost impact (based on the difference in load payments vs. generator revenue) should be considered to the extent that transmission is owned or contracted to load serving entities such that the revenue from that congestion is returned to loads, either directly or through transmission revenue rights auction revenue.

4.3.2 Application of Tests by Region

Table 4-2 below summarizes the regions in which each cost test is used and a brief description.

Table 4-2: Summary of Consumer Benefits Tests and use by Region

Test includes impact to:	Used in Jurisdictions	Description & connection to region
System Wide Gross Load Cost (GLC) Test	NYISO (supplemental information)	Measures system-wide impact on load payments at nodal prices where loads are located; Applicable if not all congestion revenue is returned to loads
Generator Revenue Reduction (GRR) Test	ERCOT	Measure system-wide impact on total payments from loads to generation at generator node, net of congestion revenue which is assumed to be returned to loads Applicable if all congestion revenue is returned to loads
Zonal Net Load Cost Test	PJM*	Measures net load cost impact for a subset of zones in the system; zones where cost to loads increase are exclude from test calculation Applicable if cost of new transmission can be assigned to a subset of zones rather than allocated equally as a system-wide cost
Transmission Economic Assessment Methodology (TEAM) Test	CAISO	Measures impact on loads plus a subset of generation & transmission that is owned & contracted to loads Applicable if a portion of generation is owned or under long-term contract
Production Cost Savings Test	MISO, SPP, NYISO, ISO-NE, AESO, AEMO, EirGrid, ERCOT	Measure total change in cost of dispatching all generation in system for serving load; Applicable as a consumer benefits test if all generation and transmission is owned or contracted to load
Congestion Cost Reduction	Various (as supplemental information)	Measure impact of congestion on pricing in the market, but not direct measurement of the magnitude of impact to consumers

*Note: PJM uses a Zonal Net Load Cost Test for projects up to single-circuit 345 kV. For regional projects with double circuit 345 KV facilities or higher, PJM uses a blended test based on 50% of the Zonal Net Load Cost Test result plus 50% of the Production Cost Savings Test result.

4.4 Evaluation for Applicability in ERCOT

E3 worked with ERCOT to define a set of relevant criteria against which to compare different congestion cost test options, and E3 evaluated the options identified from this perspective.

4.4.1 Evaluation Criteria for ERCOT

The most important criteria identified as important for evaluating a consumer cost test in ERCOT is that the test needs a clear link to how a project will create savings for ERCOT consumers. This requires that the test be consistent with key features of the ERCOT market, including:

- ERCOT has a deregulated wholesale and retail market in which generator owners, transmission owners, and retail energy providers serving loads are independent entities,
- ERCOT transmission costs are allocated on a system-wide basis equally to all loads regardless of location, and
- Congestion revenue rights are auctioned to a mix of entities including loads, generators, and third party financial entities.

Additional criteria to evaluate a cost test includes:

- Supports transmission projects that would reduce the overall level of congestion in the system. Lower systemwide congestion is beneficial to individual consumers in ERCOT because it reduces the risk that their exposure to congestion cost is not perfectly hedged,
- Provides additional perspective complementary to Production Cost Savings Test that is already being used. If a test always produces the same or extremely similar results as the Production Cost Savings Test, then it would be largely redundant, and the Production Cost Savings Test would be sufficient on its own with less additional effort provided,
- ERCOT has, or can obtain, sufficient data to implement the test in a reasonable time within ERCOT planning process framework. If a test would be useful but would require significantly more time or would require data that may not be available to ERCOT (or known at the time of the study) then that test may be less useful than another test that could be implemented more quickly.

4.4.2 Comparison of Consumer Benefit Options: Fit with ERCOT Market

Table 4-3 below summarizes the options considered compared to criteria described above. Each test is identified whether it fully does or does not fulfill the criteria, or whether it partially fulfills the criteria under certain conditions or with some challenges. Some tests involve tradeoffs between meeting different criteria, while other tests are fundamentally less applicable for the ERCOT market overall. The tests are discussed from right to left as a process of elimination.

The Production Cost Savings Test is not listed because ERCOT already uses it and plans to continue doing so to evaluate a transmission project's societal economic benefits. The remaining tests are considered for measuring consumer benefits in ERCOT, which is a parallel evaluation to the Production Cost Savings Test.

Table 4-3: Review of Consumer Benefit Options against Criteria for the ERCOT market

Criteria:	Generator Revenue Reduction Test	Gross Load Cost Test* (*Recommended Test)	Zone-specific Net load Cost Test	TEAM Approach
1. Consistent with deregulated ERCOT market structure with independent generation and loads	Yes	Yes	Yes	No
2. Consistent with allocation of transmission costs to all ERCOT load customers rather than on a sub-zonal basis	Yes	Yes	No	Yes
3. Reflects the net impact of CRR and CRR auction revenue for load customers (limited by data availability)	Partial	Partial	Partial	Partial
4. Supports projects that reduces system-wide congestion cost	Partial	Yes	Partial	Partial
5. Provides additional information beyond production cost	Yes	Yes	Yes	Limited
6. Implementable in ERCOT's current framework	Yes	Yes	With Modifications	Yes

4.4.2.1 TEAM Approach

The TEAM test, which was developed and is currently used in the California ISO market, would not accurately reflect the impact of transmission on ERCOT consumers, because far less generation is owned or contracted to market entities in ERCOT than in California. There are some exceptions in ERCOT of load serving entities also owning generation – such as the Non-Opt-In Entities (NOIEs); however, the majority of ERCOT generation is owned by entities that are independent from those serving ERCOT loads. Therefore, an increase in profits for most ERCOT generation would not likely result in a reduction to the net cost of energy for most ERCOT load customers.

As discussed in Section 4.3, some load entities have contracted with generation in ERCOT but these contracts are typically for shorter durations than contracts in California; therefore if a transmission line has changed the profits at a particular generator location (through the impact to prices), that change is likely to be reflected in the next contracting period with loads, and therefore ultimately borne by the generator owner, not the contract off-taker (load), so should not be considered part of the consumer benefits test.

Additionally, ERCOT also is not provided with full contractual data for loads and generation and this information could change for a future study year, so would be difficult to implement accurately. The nature of these contracts can be complex and difficult to reflect in a simulation model of a future year. Similarly, a TEAM test could partially reflect the net impact of congestion revenue on the ERCOT load customers, but this could require data on which transmission paths are owned by ERCOT customers.

Considering this set of results, other benefit tests are likely more appropriate for ERCOT than TEAM.

4.4.2.2 Zonal Net Load Cost Test

The Zonal Net Load Cost Test, which is used to evaluate transmission in PJM (fully for lower voltage projects and in conjunction with Production Cost Savings Test for high voltage projects), considers the benefit of transmission to loads in certain zones of a system but not to the system as a whole. This approach is appropriate for the PJM market because transmission costs can be assigned to individual zones within PJM rather than the system as a whole. ERCOT, by contrast, allocates transmission costs to loads across the full ERCOT footprint without consideration of the location of the load or of new lines. In addition to this fact, ERCOT's current transmission evaluation framework is not set up to evaluate impact to individual load zones, which could require more definition before implementing a study.

Therefore, this approach is a less suitable fit for the ERCOT market than other options available.

4.4.2.3 System-Wide Congestion Cost Reduction

Measuring the reduction in System Congestion Cost that results in from a new Transmission Project is implementable using data produced by ERCOT's existing study framework and would support identification of projects that lead to lower congestion cost in ERCOT.

The quantitative results of a Congestion Cost Reduction Test, however, do not directly indicate the amount of savings that would accrue to ERCOT energy consumers from a new transmission project, so the test may not be appropriate as a savings value to compare to the cost of that project. For example, in certain instances, if there is customer load as well as generation on one side of a major transmission constraint, that "upstream side of the constraint" may have low locational market prices, which leads to low revenue for generators there, but also low cost to the load customers in that location. If adding a new transmission project relieves the constraint (and produces a large reduction in congestion cost), it could increase the market prices on that side of the constraint and increase the cost that loads in that location pay for energy. Other loads downstream of the constraint may see lower market prices, but if prices that upstream loads pay increase by significantly more than the reduction in prices downstream, this change which reduces congestion cost could potentially lead to an increase in total costs that loads pay. In another scenario, a transmission constraint on a transmission line with relatively low throughput capacity may have an outsized effect on the market prices downstream of the constraint. In this case, a transmission project which increases transmission capacity may have a larger impact on market prices to a larger volume of downstream load than the flow on the transmission. In this situation, a congestion cost reduction may understate the potential savings to ERCOT loads.

Further complicating the treatment of how a reduction in congestion cost would impact loads is that in ERCOT some congestion cost collected in the market is returned as congestion revenue to congestion revenue rights holders in ERCOT which may include loads, and auction revenue of congestion rights also reduces cost for loads, so accurately capturing the magnitude of potential savings to load customers is difficult to ascertain from evaluating the change congest cost alone.

4.4.2.4 System-Wide GLC Test vs. GRR Test

The remaining two cost test options evaluated are the GRR Test, currently used on an interim basis in ERCOT, and the System-Wide GLC Test. These two options are more appropriate for ERCOT than the other tests considered. Between these two options, there are tradeoffs in their selection which are useful to discuss and compare.

Advantages of either test option: Both of these consumer cost test metrics apply well with ERCOT's deregulated market structure in that they do not consider profit for any generators as a benefit to ERCOT consumers. Both metrics also measure system-wide impact for ERCOT customers, rather than impact to a subset of zones in ERCOT; this system-wide perspective matches well with ERCOT's allocation of transmission costs on a system-wide basis. Both test options would be readily implementable in ERCOT's current economic transmission planning evaluation framework using available data, and both tests provide complementary information to a Production Cost Savings Test rather than showing redundant results.

Key difference between options: The key difference between these two tests is how they would treat congestion costs in ERCOT. The System-Wide GLC Test looks at the change in market prices at load locations, so a reduction in ERCOT congestion that results in lower costs for ERCOTs loads is viewed as consumer savings in this test. By contrast, the GRR Test, by using changes in prices at generator nodes, implicitly assumes that 100% of the congestion costs in the system (that is the differences in what loads pay versus the revenue that generators receive) is returned to load customers, through a combination of Congestion Revenue Rights (CRR) payments (which accrue to load customers that hold CRRs) and through the proceeds of CRR auctions (which accrue entirely to load customers, regardless of whether they hold CRRs)..

Evaluating the most applicable option for ERCOT: The most important criterion to consider in selecting between these two tests for ERCOT is: Which of these two options more accurately reflects how a new transmission project would affect ERCOT consumers? The answer to this question depends on the extent to which one option or the other more accurately reflects the extent to which congestion costs are returned to ERCOT load customers versus remaining solely a cost that they incur through market prices. If all congestion costs are returned to ERCOT consumers, then ERCOT consumers would be "fully hedged" against congestion cost in the system, and the Generator Revenue Reduction Test's approach would be most appropriate. In that case, a new transmission project which reduces congestion may lower locational prices loads pay, but also would reduce the congestion revenue they get back resulting in a partially neutralized impact.

If instead, a significant share of congestion is not returned to consumers, then the cost of congestion, which drives prices that ERCOT loads pay, would represent a real cost to consumers, and the System-Wide GLC Test would be more appropriate. In this case, a new transmission line which reduces congestion and lowers locational prices that loads pay creates real savings for consumers, which is not offset by the change in potential congestion revenue they receive.

E3 reviewed recent reports regarding treatment of congestion revenue in the ERCOT market and discussed this topic with the ERCOT planning team and market operations staff. This review indicates that a portion, but not all, congestion cost on the ERCOT system accrues as revenue back to ERCOT consumers. Therefore, either test option (GRR Test or System-Wide GLC Test) partially but do not perfectly reflect the impact of congestion costs on ERCOT consumers at any point in time.

Congestion revenue background: The system-wide congestion cost represents the difference in cost that ERCOT loads pay (based on market prices at load locations) versus the revenue that generators receive (based on market prices at generator locations). Due to congestion, loads on average will pay higher prices than revenue that generators receive, so all market operators using nodal prices must determine a method of disbursing the difference in the amount collected from loads vs. what is paid to generators. ERCOT, like many other markets, holds recurring auctions in which a wide range of entities (generator owners, load customers, and third parties including financial entities without physical assets or loads in the system) can bid to acquire a congestion revenue right, which is a payout of a portion of the system-wide congestion revenue. These auctioned rights pay out based on the locational price difference (in $/MWh) at any pair of nodes within the transmission system multiplied by the MW of rights acquired for a particular time horizon. Pairs of locations where more congestion and larger price differences are expected will typically have higher auction prices applied, and recent historical congestion informs auction bids. Proceeds of the auction are treated as a reduction to ERCOT transmission rates, so these proceeds ultimately accrue back to ERCOT load customers. A small portion of congestion revenue rights in ERCOT are pre-assigned without cost to ERCOT's Non-Opt-In Entity (NOIEs), which also serve loads in certain portions of ERCOT. Therefore, a portion of congestion cost accrues back to ERCOT loads through three potential mechanisms:

(1) Auction proceeds accrue to ERCOT load customers through reduction to transmission rates,
(2) If ERCOT load entities successfully bid on congestion revenue rights, the payout of the congestion revenue for the selected congestion revenue right (net of the bid price) will be a benefit for load entities,
(3) Loads served by Non-Opt-In Entities (NOIEs) receive the payout of any pre-assigned congestion revenue rights (PCRR) granted to those entities by ERCOT.

On a system-wide basis, the 2022 Annual Report on Market Issues and Performance in ERCOT summarizes the total congestion cost in ERCOT for recent years and compared this to the total auction revenue from revenue rights auctions for those periods. In 2022, congestion rent across the ERCOT system totaled $2.5 billion, while auction revenue ERCOT received for the year was $1.2 billion. Figure 38 of that report indicates that this pattern of lower auction revenue than total market congestion has been consistent in all years since 2016, though at a lower magnitude for both congestion and auction revenue. This confirms that in practice, not all congestion revenue is typically returned to customers through auction revenue.

ERCOT currently does not have sufficient data to isolate the impact of CRR payouts that accrues to load customers only (versus to other entities participating in the auction) so it would be challenging to estimate the total portion of CRR revenue to attribute to consumers. This challenge is particularly acute when applied to a future evaluation year because different entities could bid on different congestion rights in those years causing revenue to be allocated differently than in a historical period.

Implications for consumer cost test metric: Because some but not all congestion revenue is returned to ERCOT customers, selecting between the GRR and System-Wide GLC Test involves a selection of which option comes closer to accurately capturing the impact of transmission on load customers while recognizing that neither perfectly calculates that impact.

In consideration of this tradeoff, the GRR would risk over-accounting for the amount that loads are hedged against congestion in ERCOT, and so risks understating the potential value of that new transmission projects may create for ERCOT consumers. By comparison, the System-Wide GLC Test, which more conservatively accounts for the impact of congestion revenue to loads, instead would reflect a reduction to congestion as a portion of the benefit to load customers.

Because of this difference, the Gross Load Cost Test will also show greater value for transmission projects that reduce congestion in the ERCOT system, and lead to more likely support for those projects. This consideration is a meaningful advantage in the ERCOT system, as system-wide congestion costs have grown rapidly from under $500 million in 2016 up to $2.5 billion in 2022. Even though a portion of this congestion is returned to loads through auction revenue or through CRRs that they purchase, the impact of congestion (and the payout of any CRRs they hold) likely affects individual load entities differently and therefore represents an increase to price risk for those entities. Even under a counterfactual scenario in which all congestion cost was returned to loads customers as a whole and loads as a whole were neutral to congestion costs, the risk to individual load serving entities likely means that it would be better for loads to exist in a system with lower congestion cost, as well as lower congestion revenue returned to them.

Therefore, the Gross Load Cost Test appears to be the most useful test for ERCOT among the options identified in other regions and considered in this study.

4.4.2.5 Alternative Option: ERCOT-Specific Texas Transmission Test

Recognizing that neither the Gross Load Cost Test nor the GRR perfectly captures the likely impact of congestions costs to ERCOT consumers, E3 explored with ERCOT whether a bespoke test customized to the ERCOT market could provide a better approach.

As noted in the prior section, data limitations are the primary challenge for fully capturing the impact of congestion on ERCOT customers. Even for a historical ERCOT currently does not receive full information on the entities that successfully bid for congestion revenue rights at any given time and these entities sometimes have other contractual arrangements with third parties, so identification of how much CRR revenue comes back specifically to ERCOT load customers is challenging with current data collected. Additionally, auctions occur on a monthly and semi-annual basis, so the winning bidders who hold CRRs in a future study year for a transmission project may be considerably different than those from a recent historical auction, and the prices they paid for these rights may be different.

Thus, it is likely impossible to perfectly quantify the exact connection between congestion cost and consumer impact in ERCOT for a future year. It may, however, be worthwhile for ERCOT to explore whether data that ERCOT does have could move toward an improved or more accurate test calculation. For a simple example, if ERCOT were to use the ratio of actual CRR auction proceeds to total congestion in a recent historical year (e.g., $1.1 billion auction proceeds in 2022 versus $2.5 billion in congestion), or on average over the three most 3 recent years, this ratio could be used as an assumed percentage of the change in congestion revenue in a study case that would accrue to loads. For example, if a transmission line reduced system-wide congestion by $100 million in the study year, ERCOT might estimate that expected auction proceeds (returned to loads) may decline by $100 million * ($1.1 billion / $2.5 billion) = $44 million, and then subtract this impact as an offset to the Gross Load Cost savings already calculated.

This simple example is illustrative only, but over time it may be useful for ERCOT to explore whether data it could obtain could provide sufficient quality information to refine the estimate of consumer savings from a transmission project. The tradeoff consideration to any improvement would be to avoid introducing “noise” or inaccuracies that complicate producing a consistent and reliable value for transmission savings to consumers. Additionally, data would need to be obtainable in a sufficiently timeline manner and format that could be implemented in ERCOT's existing framework. It would be counterproductive if such information provided a small additional improvement in accuracy while significantly slowing the ability to calculate transmission benefits from different studies.

It should be noted that any results with a refined treatment of the partial return of congestion revenue to ERCOT customers would produce a consumer benefits test result that falls in between the results of the Gross Load Cost Test and the Generator Revenue Reduction Test, so those two tests represent boundaries of the potential outcome of any refined test.

Therefore, the final cost test that E3 recommends for ERCOT would be either:

(a) The System-Wide Gross Load Cost (GLC) Test; or
(b) If sufficient data is identified by ERCOT to reliably estimate the return of the congestion cost to loads, use a customized ERCOT-Specific Texas Transmission Test, in which ERCOT begins with the Gross Load Cost Test and nets off the portion of congestion revenue that ERCOT loads are expected to receive back.

5 Summary: Recommendation for Consumer Benefits Test in ERCOT

E3 reviewed economic benefits tests used in jurisdictions throughout North America, as well as in Australia and Ireland, to provide a wide range of options for application in the ERCOT market. E3 created a set of criteria to identify which options was most appropriate to utilizing in ERCOT for estimating the potential consumer benefit of new transmission projects to ERCOT load customers. Based on this evaluation, E3 recommends the System-Wide Gross Load Cost (GLC) Test as the best option to fit with the rules and structure of the ERCOT market.

This cost test directly estimates the impact of new transmission on energy costs to ERCOT consumers by calculating how it changes the energy cost paid at ERCOT customer locations. If a new line enables prices to go down where customers are located, ERCOT will show that reduction in annual cost to loads a consumer benefit or savings, and ERCOT will then compare that to the cost of building the transmission project to determine whether the project would produce net savings to ERCOT consumers.

This approach will:

- Have a clear link to ERCOT customer savings, recognizing key features of the ERCOT market,
- Support projects that reduce system-wide transmission congestion in ERCOT,
- Provide a complementary perspective on transmission value to the Production Cost Savings Test, which ERCOT will also continue to use, and
- Be straightforward to implement using ERCOT's existing study approach and software.

One tradeoff of this test approach is that it may not fully capture the impact of ERCOT load customers being partially hedged to consumer costs through purchases of Congestion Revenue Rights (CRRs) in auctions, and through the proceeds of those auctions. ERCOT reports indicate that these mechanisms mean that ERCOT loads as a whole are partially but not fully hedged to congestion costs in the system, though individual loads serving entities may be more or less hedged than others.

Therefore, E3 recommends that it may be useful for ERCOT to continue to review data available to estimate the aggregated impact of congestion, including auction revenue allocation, on ERCOT loads, and, in future study work, potentially use this information to refine the Gross Load Cost Test used to estimate consumer benefits, if this refinement does not introduce too much noise or variation to study results and does not materially slow the study process.

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