The Brattle Group

Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process

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Judy W. Chang

Johannes P. Pfeifenberger

Samuel A. Newell

Bruce Tsuchida

J. Michael Hagerty

Prepared for

ERCOT

About the Authors

Judy Chang, Johannes Pfeifenberger, and Sam Newell are Principals, Bruce Tsuchida is a Senior Consultant, and Michael Hagerty is an Associate at *The Brattle Group*, an economic consulting firm with offices in Cambridge Massachusetts, New York City, Washington DC, San Francisco, London, Madrid, and Rome. They can be contacted at www.brattle.com.

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RECOMMENDATIONS FOR ENHANCING ERCOT'S LONG-TERM TRANSMISSION PLANNING PROCESS

EXECUTIVE SUMMARY

The Electric Reliability Council of Texas (ERCOT) engaged *The Brattle Group* (*Brattle*) to review ERCOT's process for screening economic transmission projects in its Long-Term Study (LTS) process, prepare recommendations on how to estimate more completely the economic value of transmission projects from a societal benefits perspective, and present before the ERCOT Long-Term Study Task Force (LTSTF) recommendations to improve the "Business Case" for economic transmission investments.

This effort focused specifically on ERCOT's 10-year Long-Term System Assessment (LTSA) methodology and the new 10- to 20-year scenario-based LTS process that ERCOT developed with support and funding from the U.S. Department of Energy (DOE). We examined those processes by interviewing stakeholders and ERCOT staff, carefully reviewing the available documentation, modeling tools, and evaluation criteria used by ERCOT, and obtaining input from ERCOT and stakeholders on our draft findings. Insights from our review and comparison to industry best practices have led us to recommend improvements to the LTS and LTSA processes. Our recommendations center on how ERCOT can more accurately and more completely assess the wide range of economic benefits that new transmission projects can provide to the system. Relatedly, we also assisted ERCOT staff in improving its analytical framework for comparing long-term benefits to project costs. As discussed further below, the specific recommended improvements include: (1) linking near- and long-term planning processes; (2) evaluating economic projects based on their net present value (NPV) or a comparison of levelized benefits and costs; (3) expanding the scope of benefits considered and quantified; (4) improving the use of scenarios and sensitivities; and (5) enhancing the process for identifying projects and the benefits/costs associated with specific projects.

With our recommended improvements, ERCOT will be able to identify economically-beneficial long-term transmission investments more effectively and to use that information in the evaluation of projects within its near-term (5 to 6 year) Regional Transmission Plan (RTP) process used to create ERCOT's actionable transmission plans.

A. SUMMARY OF FINDINGS

In our effort of evaluating ERCOT's long-term transmission planning process and identifying possible improvements, the *Brattle* team:

1. Reviewed ERCOT's long-term transmission planning scope and process;
2. Solicited ERCOT stakeholder input;
3. Reviewed ERCOT's modeling infrastructure and process;

4. Identified additional benefit metrics for more fully valuing transmission-related societal benefits and worked with ERCOT to develop case studies for evaluating the benefits;
5. Developed recommendations to: (a) improve ERCOT's transmission planning process for economic projects; (b) enhance its modeling infrastructure and practices; and (c) increase the scope of economic benefits through additional benefit metrics that should be considered in ERCOT's planning process; and
6. Presented findings and recommendations to ERCOT staff and ERCOT stakeholders.

Below is a brief summary of the findings from each of Tasks 1 through 4:

1. Review of ERCOT's Long-Term Planning Process

Prior to working with ERCOT staff and stakeholders, we reviewed ERCOT documentation of the DOE-sponsored LTS effort, its stakeholder processes, and prior Five-Year Transmission Plan and LTSA reports. Our document review was supplemented with interviews with ERCOT staff and stakeholders, as summarized below. We thereby identified the following topics where significant opportunities exist for ERCOT to improve the evaluation of economic transmission projects:

- ERCOT conducts two separate processes for its long term (10 to 20 year) and near-term (5 to 6 year) planning, making it difficult to compare project benefits across different timeframes. This hinders using results from the long-term planning process to evaluate projects (or project alternatives) in the actionable near-term planning process as intended.

- ERCOT currently compares estimated first-year production cost savings of an economic project with the project's first-year transmission revenue requirements (TRR), net of the TRRs of reliability projects that can be deferred or avoided by the economic project. This approach effectively imposes an impractically high threshold, because it ignores that benefits would typically increase over time with fuel cost inflation and load growth while the TRR of a project would decrease over time as the asset is depreciated.

- ERCOT currently compares project costs with only two limited sets of benefits in its economic project evaluation process: (1) a conservatively-low estimate of production cost savings based on simplified market simulations; and (2) the avoided TRR of deferred or replaced reliability projects. Transmission investments can provide a much wider range of benefits (or costs) that should be considered when evaluating economic projects. Other system operators have recently expanded their economic project evaluation processes to consider or evaluate up to a dozen distinct economic benefit metrics, most of which are applicable in ERCOT as well.

2. ERCOT Stakeholder Input

The *Brattle* team interviewed a wide range of ERCOT stakeholders to inform our understanding of the existing transmission planning process and to help assess what works well and where improvements are needed. The stakeholders included utilities, transmission developers, generators, industrial consumers, landowners, market analysts, and the ERCOT Independent Market Monitor (IMM). Stakeholders provided extensive input on the long term planning process overall, on the changes currently underway in the process, and on other potential enhancements and concerns. Stakeholders also provided additional written comments in response to our findings and draft recommendations, which were presented on June 3, 2013.

Stakeholder input generally was focused on: (1) the purpose and the value of long term transmission planning in ERCOT; (2) the future scenarios and input assumptions developed for the long term study process; (3) the involvement of stakeholders in the long-term planning effort; (4) the scope of benefits and costs of transmission that should be considered in the planning process, and (5) specific feedback on our draft recommendations. For the first four of these topics, stakeholder comments included the following:

- *Use of Long-term Studies in Developing Transmission Expansion Plans*: Stakeholders generally appreciated the efforts ERCOT has made in planning the transmission system beyond the near term, and a subset of stakeholders felt that ERCOT's long-term studies are invaluable. Other stakeholders saw little value in long-term studies given the considerable uncertainties that exist beyond the 3- to 6-year time frame already considered in the RTP and former Five-Year Transmission Plan process—particularly given that the time needed to develop and construct new transmission in Texas is relatively short (*e.g.*, within the RTP timeframe). Further, some questioned the effectiveness of the existing process and expressed hope that, as ERCOT and stakeholders become more familiar with the new process, ERCOT would enhance its planning process over time. Some were particularly interested in developing a better understanding of the goals of the LTS process and how long-term planning results will be used to inform the near-term planning process that produces actionable projects. Many believed the LTS process should be used to identify more economically-efficient long-term solutions to transmission needs that would otherwise be resolved incrementally through reliability upgrades.

- *Future Scenario Development*: Many stakeholders showed particular interest in the future scenarios that were developed to inform the long-term transmission planning effort and appreciated that the process involved stakeholders. However, some believed that their opinions had not been fully considered in the scenario development process. Almost all of those who provided feedback expressed concern that some aspects of the chosen scenarios have been unrealistic. A subset thought the range of scenarios was too narrow and recommended that a more divergent set of scenarios, including extremes, be developed in order to evaluate the system near its breaking points and understand what system improvement could be valuable in those situations. Stakeholders consistently commented that the results of future long-term studies will only be accepted if a wide range of stakeholders consider the future scenarios used to be credible and that the associated input assumptions are reasonable. There was general agreement that the current scenarios will need to be refined further and that increased stakeholder engagement will be needed to achieve acceptance of long-term planning results.

- *Stakeholder Involvement*: Most stakeholders expressed considerable interest in continued involvement in long term planning, especially in the development of scenarios and in reviewing results. Several stakeholders hoped that ERCOT would more deliberately incorporate input from transmission owners with specific local knowledge. Some suggested soliciting input on scenarios from a wider range of sources, including expertise from outside ERCOT and possibly outside the electric power industry (such as the oil and gas industry). In contrast, a few stakeholders expressed concerns about their ability to be involved in the process due to the highly technical nature of the discussions, the significant commitment of time and resources needed for participation, and the currently limited use of long-term study results.

- *The Scope of Transmission Benefits Considered*: Many stakeholders were receptive to considering additional categories of benefits in the transmission planning process. Some stakeholders expressed that transmission investments offer many benefits that should but have not yet been considered in ERCOT's planning process. In contrast, some are concerned that considering additional benefits will lead to an increase in unnecessary transmission build-out that could adversely affect electricity customers, land owners, and possibly other market participants. A few stakeholders also suggested broadening the scope of costs considered in the long-term study process, such as the costs of balancing the intermittent resources that are facilitated by new transmission lines and the cost associated with lost land value. Several stakeholders also suggested that ERCOT and the Public Utility Commission of Texas (PUCT) consider electricity customer benefits metrics in addition to relying solely on societal benefits.

3. Review of ERCOT Modeling Infrastructure and Process

We interviewed ERCOT modeling staff within the long-term, near-term, and resource-adequacy modeling groups and reviewed the documentation of the modeling processes they employ. The objective of the interviews was to identify opportunities for improving the modeling process and practices, including staff training needs (if any). While we acknowledge the concerns from stakeholders about certain assumptions that ERCOT has made in developing future scenarios in its 2012 LTS, our modeling interviews only focused on ERCOT's technical capabilities and methodologies, without examining potential improvements to the scenarios themselves nor the specific assumptions used in depicting each scenario.

Overall, we found that ERCOT's modeling processes are well designed and documented, and the modeling team members demonstrated strong expertise in transmission and economic modeling, with no identified need for additional market simulation training. While further improvements are possible, several modeling techniques used by ERCOT are best-in-class, such as the methodology for adding future generation to the model where most economic (considering factors such as environmental siting challenges in load pockets, fuel supply, and locational market prices or LMPs) and making the appropriate technical adjustments to ensure that transmission constraints are modeled properly when making major additions of resources or transmission. Other best practices include the use of transmission reliability models alongside economic models and documentation of the process steps and results.

Our interviews with ERCOT's modeling staff and our review of their modeling processes revealed three areas that could be improved to support long-term planning more effectively.

- *Organizational and Modeling Team Structure*: ERCOT has two separate sub-groups, each with its own production cost model and its own set of inputs covering different timeframes. This creates duplication of work and risks inconsistencies in the modeling efforts. Having separate modeling teams also hinders the exchange of ideas and best practices between teams working on similar issues. We understand that ERCOT has already begun to address this concern by re-organizing the teams' structure to make it more efficient and consistent.
- *Designing Study Cases*: ERCOT could improve its modeling by defining selected scenarios in a way that is more credible to stakeholders. Other potential improvements include more fully representing generation outages (and other system stresses in the context of additional benefit metrics as discussed below) that regularly increase congestion. Study cases should also be defined carefully to distinguish between alternative and complementary transmission projects when evaluating portfolios of projects.
- *Validation of Results*: ERCOT has performed some model validation in the past when the modeling tools were initially developed. Such model validation and calibration efforts should be undertaken on a more regular basis to ensure that the market simulations can reasonably represent actual market conditions, market prices, and congestion patterns.

4. Benefit Metrics Considered

Establishing a robust business case for new economic transmission projects requires fully capturing the economic value that a transmission investment can provide to the system and properly accounting for the costs and benefits over the life of the project. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to not considering all costs and the potentially very-high-cost outcomes that market participants would be exposed to in the absence of these investments.

The two benefits currently considered by ERCOT in its planning efforts for economic transmission projects—modeled production cost savings and deferred or avoided reliability upgrades—do not capture the full societal benefits and costs of transmission infrastructure investment. While estimating and using these two benefit metrics represents a good starting point, they reflect a narrow subset of the wider range of benefits that are increasingly considered in the industry today, including by other system operators in Texas and surrounding regions.

To allow ERCOT to benefit from the quickly evolving industry experience, we document the types of transmission-related economic benefits quantified and considered by other system operators in Texas, neighboring regions, and other parts of the U.S. Based on a review of this industry experience and our own, we provided ERCOT with a comprehensive "checklist" of potential economic benefits of transmission infrastructure investments. This checklist, summarized in Table ES-1, served as the starting point to discuss the additional economic benefit metrics that ERCOT could develop and incorporate in its transmission planning efforts over time. As noted during our presentation to stakeholders and ERCOT staff, this checklist of potential benefits does not necessarily mean that every category of benefit would increase the value of all transmission projects; some of these benefit categories may yield negative values for certain projects, thus representing societal costs.

We reviewed the list of potential metrics with ERCOT staff, assessed their relevance to ERCOT, and identified the most promising metrics that could be added by ERCOT immediately to improve its current modeling practices. We also identified promising benefit metrics that will require the development of additional modeling tools and analytical capabilities. In parallel, ERCOT has begun to develop case studies that apply some of the identified approaches and metrics to gain familiarity with the necessary modeling and analytical efforts necessary to build the "tool kits" that can be used to evaluate proposed economic transmission projects in the future. The recommendations for near-term implementation are summarized in the right column of Table ES-1 and are discussed further below. Additional recommendations concerning benefit metrics that ERCOT should consider developing in the longer-term are discussed in the main body of the report.

Table ES-1
Checklist of Benefits and Recommended Metrics for Implementation

Checklist of Potential Economic Benefits of Transmission		Already Used	Recommended for Near-Term Implementation
1. Traditional Production Cost Savings *(as currently considered by ERCOT)*		✓	Improve
1a – 1i. Additional Production Cost Savings			
a.	Impact of generation unit outages and designations for ancillary services		✓
b.	Reduced transmission energy losses		✓
c.	Reduced congestion due to transmission outages		✓ (multiplier)
d.	Mitigation of extreme events and system contingencies		
e.	Mitigation of weather and load uncertainty		✓ (multiplier)
f.	Reduced costs due to imperfect foresight of real-time conditions		
g.	Reduced cost of cycling power plants		✓
h.	Reduced amounts and costs of ancillary services		
i.	Mitigation of RMR conditions		
2. Reliability and Resource Adequacy Benefits			
a.	Avoided or deferred reliability projects *(as already considered by ERCOT)*	✓	Improve
b.	Reduced loss of load probability, or:		
c.	Reduced planning reserve margin		
3. Generation Investment Cost Savings			
a.	Generation investment cost benefits from reduced peak energy losses		✓
b.	Deferred generation capacity investments		Case by case
c.	Access to lower-cost generation		Case by case
4. Market Benefits			
a.	Increased competition		
b.	Increased market liquidity		
5. Environmental Benefits			
a.	Reduced emissions of air pollutants		✓
b.	Improved utilization of transmission corridors		Qualitative
6. Public Policy Benefits			
a.	Reduced cost of meeting public policy goals		
7. Employment and Economic Stimulus Benefits			
a.	Increased employment and economic activity; increased tax revenue		
8. Other Project-Specific Benefits			
such as:	Storm hardening, load serving capability, synergies with future transmission projects, fuel diversity and resource planning flexibility, wheeling revenues, transmission rights and customer congestion-hedging value, HVDC operational benefits		Case-by-case

B. Summary of Recommendations

Based on our review of ERCOT's long-term transmission planning process and the findings summarized above, we developed the following recommendations for further consideration by ERCOT and its stakeholders. The initial draft of these recommendations, as summarized in Table ES-2, was presented to stakeholders in a public meeting on June 3, 2013.

Table ES-2

Recommendations for Enhancing ERCOT's Transmission Planning Process	
1:	Link Near- and Long-term Planning Processes
2:	Evaluate Economic Projects based on their NPV or a Comparison of Levelized Benefits and Costs
3:	Expand Benefits (and Costs) Considered and Quantified
4:	Identify Key Uncertainties and Improve Development and Use of Scenarios and Sensitivities
5:	Enhance Economic Project and Benefits/Costs Identification Process

We received eleven sets of stakeholder comments in response to the draft recommendations presented at the stakeholder meeting. The comments covered a diverse set of opinions, ranging from broad support for the presented recommendations, to the recommendation that new transmission projects should only be planned to maintain reliability and lower costs to consumers (as opposed to considering societal benefits), to concerns about the value or process of scenario-based planning, and the position that benefits more than a few years in the future are highly speculative and should not be considered. In general, however, the majority of stakeholders support: (a) linking the long-term planning effort to the near-term RTP process for the evaluation of economic projects; (b) adding at least a subset of the potential additional benefit metrics (after considering additional stakeholder input); and (c) utilizing NPV concepts in comparing costs and benefits (although differences of opinions exist about the discount rates that should be applied to long-term benefits and costs).

Our finalized recommendations are summarized below:

1. Link Near-Term and Long-Term Planning Processes

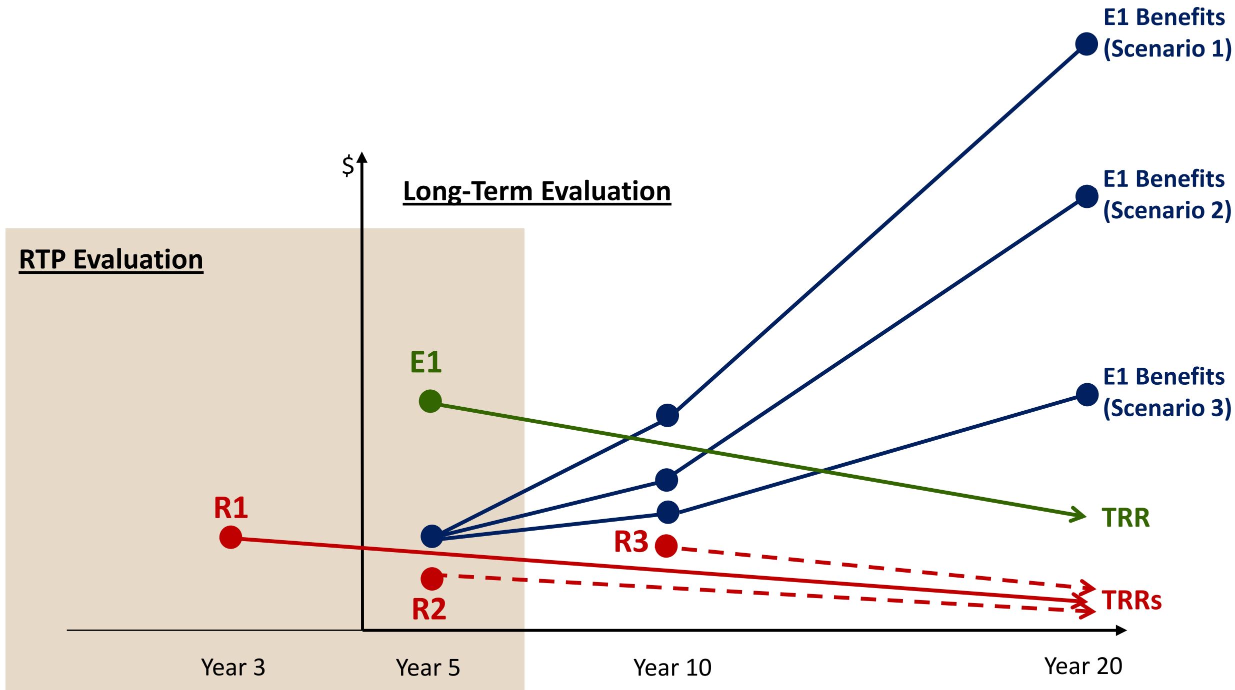
We recommend that ERCOT more systematically link its long-term (LTSA) transmission planning processes to the near-term (RTP) planning process. Such a linkage would increase the consistency in modeling assumptions and results across the two planning horizons, avoid overlapping modeling efforts, and allow the effective use of results from long-term studies to inform near-term planning efforts. Accordingly, we also recommend integrating ERCOT's near- and long-term modeling teams and using a single economic model with consistent input assumptions for both the near-term and long-term analyses. Such integration would help improve the quality, consistency, and efficiency of the workflow and enable a more integrated transmission planning process going forward.

Specifically, we recommend that ERCOT use the results of its long-term studies in the identification and evaluation of economic transmission projects within its RTP process. Transmission needs would continue to be determined and approved primarily through the RTP process, with most projects considered to be built over the ensuing 5 to 6 years of the RTP time frame. However, the monetary value of the benefits and costs of economic projects that could be developed within that 5 to 6 year time frame would be estimated based on results from both the near-term and long-term analyses. Utilizing information about the benefits and costs of an economic project over a significant portion of its useful life would help determine the actual economic value of a project, which in turn would help assess more accurately the tradeoffs between incremental reliability upgrades and economic project alternatives.

Figure ES-1 illustrates our recommendation of linking the near- and the long-term planning processes. This hypothetical example compares annual dollar values (y-axis) over time (x-axis). The RTP process (over the first 5-6 years) is represented by the shaded block on the left. In this illustration, the RTP process identified two reliability upgrades, "R1" and "R2," which would be needed in years 3 and 5, respectively. The red dots and lines corresponding to R1 and R2 represent the regulated annual costs of the reliability projects (in terms of annual transmission revenue requirements or "TRRs"). These annual costs decline as the assets are depreciated over their useful life (typically over 40 to 50 years).

Figure ES-1 also shows an economic transmission project, "E1," proposed to be installed in year 5. In this example, if E1 were built, R2 would not be needed. The green dot and line that correspond to E1 illustrate that the annual costs of E1 are significantly higher than the annual costs of R2 (as illustrated by the red dot and dashed line). However, in addition to avoiding the construction of R2, the development of E1 would also offer incremental production cost savings (above those associated with R2) as indicated by the three trajectories of blue dots and lines. The three blue lines depict the project's total annual savings under three alternative future scenarios.

Figure ES-1
Linking Near-Term and Long-Term Evaluation of Economic Projects



Under ERCOT's current evaluation process, the first-year revenue requirements of Project E1, net of the avoided first-year costs of R2 would be compared to the annual production cost savings achieved by E1 in its first year. With such a comparison and threshold, as illustrated, Project E1 would be rejected because its first-year costs exceed the sum of avoided R2 costs and production cost savings in that year. This approach ignores the potentially very different future balance of costs and benefits that would make Project E1 a better long-term choice even in year 5 of the RTP evaluation.

The three blue lines show that, under the three alternative future scenarios, the total long-term savings offered by E1 in its first operating year (i.e., year 5) would grow at different rates over time, consistent with the typical trends caused by the combined effects of load growth and increasing fuel prices. It is also possible that the production cost savings would decrease over time, for example, if load and fuel prices decreased or if future reliability projects offered overlapping production cost savings as E1. The three different trajectories of annual benefits depend on the assumptions used in depicting the alternative future scenarios.

The hypothetical example shown in Figure ES-1 reflects the assumption that if E1 were built in year 5, it would also avoid another reliability upgrade, "R3," in year 10 (which would likely be identified in the subsequent RTP evaluations, in absence of E1). Thus, an evaluation of whether the economic project E1 should be pursued requires estimates of avoided reliability project costs that would be offered by E1 over time.

In Figure ES-1 we only show the hypothetical annual production cost savings of E1 and the avoided annual cost of reliability upgrades R2 and R3. Nevertheless, as illustrated, while project E1 could not be justified by comparing first-year costs with its limited first-year benefits, the total cumulative *value* of the economic project's benefits, even if annual benefits are increasingly discounted over time, would significantly exceed total project costs under most if not all future scenarios.

As the illustration in Figure ES-1 shows, the economic project E1 would still undergo evaluation and approval through the RTP process for completion in year 5, but the comparison of its benefits and costs would be informed by the results from the long-term assessment that reaches out 20 years. The scenario-based long-term assessment would also indicate the robustness of the economic project's value under the alternative future scenarios, which can also be considered in the RTP process.

2. *Evaluate Economic Projects based on their Net Present Value (NPV) or a Comparison of Levelized Benefits and Costs*

The economic benefits of transmission projects and their alternatives accrue over the entire life of the asset. We consequently recommend that the long-term value of costs and benefits be considered in the evaluation of potential economic transmission projects. While decisions about necessary reliability-driven transmission projects can be made based on conditions in the year when the identified reliability need first occurs, decisions about economically-justified projects require the assessment of economic value, which is defined by the benefits and costs that accrue over the useful life of the investment.

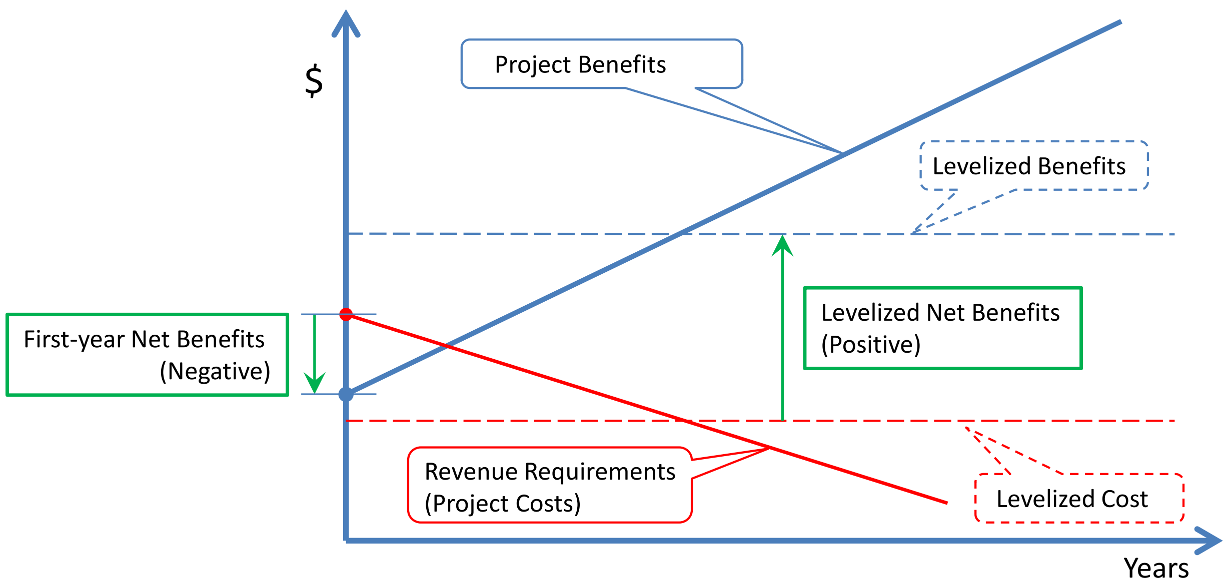
The current ERCOT practice used to evaluate economic projects typically performs production simulations only for the first year of the proposed project. ERCOT then compares the first-year production cost savings against $1/6^{th}$ of the project's construction costs, net of $1/6^{th}$ of any avoided reliability project costs in that year. Taking $1/6^{th}$ of a project's construction cost is approximately equal to the project's regulated cost of service (*i.e.*, its regulated transmission revenue requirement or TRR) in the first year. This approach carries a high risk of rejecting potentially beneficial economic projects for three main reasons:

a. Production cost savings and other benefits tend to grow over time with increasing load and fuel prices. As a result (although this is not always the case), the production cost savings for the first year of a project are generally lower than the "levelized" annual benefit that reflects the project's average savings over time. Figure ES-2 below illustrates how the levelized annual value of long-term benefits can be much larger than the benefits in the first year of a new project. As illustrated, it can easily be the case that first-year net benefits are less than first-year costs, even though levelized net benefits significantly exceed both first-year costs and levelized costs.

b. Transmission revenue requirements decline over time as the assets are depreciated. The first-year TRR of a project, estimated as $1/6^{th}$ of its construction cost, is approximately 30% higher than the levelized annual value of its TRR over time. Thus, if benefits need to exceed the 1/6th of the project's construction cost, then the levelized benefits need to be approximately 30% greater than the project's levelized revenue requirements.

c. The economic project may offer benefits beyond production cost savings and avoided reliability project costs that should be considered as well. We discuss this point in Recommendation No. 3 below.

Figure ES-2
Comparing First-Year and Levelized Project Costs and Benefits



For these reasons, we recommend that the costs and benefits associated with proposed transmission projects be compared based on their present values or levelized values. The present value approach compares the present value of a project's long-term benefits to the present value of a project's costs. The present values of benefits and costs are estimated as the sum of annual benefits and annual costs, both increasingly discounted over time to reflect the fact that a dollar spent or saved 10 or 20 years from now is significantly less valuable than a dollar saved or spent today. To estimate annual benefits over time, the annual values for some years can be interpolated based on specific estimates for a few future years, such as year 1, year 5, and year 10 (or year 20) and extrapolated further into the future based on a conservative assumption of how benefits would grow or remain constant over time, recognizing that the value of transmission investments rarely declines over the long term.

The time frame over which the present values of benefits and costs are calculated is often 20 or 40 years in other planning regions, although some system operators use time horizons as short as 10 years while others estimate values over the full 50 years of a project's assumed life. We recommend that ERCOT consider estimating benefits and costs over a 20 to 40 year period, consistent with the time horizon used in neighboring regions.

Regarding discount rates applied to project costs and benefits, we recommend using the weighted average cost of capital of the transmission owners, although some planning regions (such as the Midcontinent ISO, MISO) also use a lower "societal" discount rate for both costs and benefits. We recommend against applying a higher discount rate to transmission benefits than the discount rate that is applied to annual transmission costs. Rather, we recommend a PUCT-approved weighted average cost of capital for transmission owners to discount both future benefits and costs. This rate appropriately reflects the risks of transmission investments. Using a higher rate would understate the potentially high costs imposed on market participants in the absence of the contemplated transmission investment. Any higher perceived uncertainties associated with estimated benefits are already addressed through benefit-cost thresholds that exceed 1.0 (such as 1.25 in most other regions) and the recognition that many transmission-related benefits often are not quantified.

As an alternative to comparing the present values of benefits and costs, it is equally suitable to compare the benefits and costs using levelized annual values. This is because the "levelized" costs and benefits are the equalized annual values that yield the same present values as the estimated time-varying amounts. Such NPV-based or levelized benefit and cost comparisons are used by virtually all other system operators and we recommend ERCOT adopt a similar methodology.

ERCOT's approach of comparing the benefits of a project with 1/6th of the project's construction costs (as an estimate of the project's first year of revenue requirements) is consistent with recent orders from the PUCT. However, as shown in Figure ES-2, the first-year TRR of a transmission project is at its highest relative to the rest of the useful life of the project. Under typical ratemaking treatment of transmission costs, a project's first year TRR is approximately 30% higher than the levelized value of these TRRs that yields the same present value over the project life as the actual declining profile of TRRs. Thus, comparing levelized benefits to 1/6th of the project's construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceeds 1.3 from a present value perspective. We do not advise modifying this criterion at this point, but recommend that ERCOT also calculate a project's benefit-cost ratio based on levelized benefits and levelized costs to recognize the extent to which this approach requires that the value of estimated benefits exceed estimated costs.

3. Expand The Range of Benefits (and Costs) Considered and Estimated in the Evaluation of Economic Transmission Projects

We recommend that ERCOT more fully consider and estimate the economic value of transmission investments. This requires expanding the economic benefits and costs of transmission investments considered in ERCOT's planning efforts. The wider range of benefits and costs will more accurately reflect the value that new transmission can provide to the system.

As it would be difficult for ERCOT to evaluate the complete set of benefit metrics shown in Table ES-1 above for each proposed project, we recommend that ERCOT implement only a subset of these benefits and benefit metrics in the near term. As we explain in more detail in the full body of the report, we recommend that ERCOT improve its treatment of production cost savings and the benefits from deferring or avoiding reliability projects. We also recommend that ERCOT estimate seven additional benefit metrics in its economic evaluation process, two of which would be applied as a typical multiplier to standard estimates of production cost savings. These additional metrics could be applied to each major economic project or portfolios of projects found most promising based on production cost savings and avoided or deferred reliability projects.

The scope of production cost savings, as currently estimated by ERCOT, should be expanded to include estimates of savings beyond a project's first year. For example, a reasonable approach would be to estimate savings for years 1, 5, and 10 of a project and then use these annual estimates to develop estimates for the long-term present value of a project's production cost benefits. The estimated benefit of an economic project's ability to defer or avoid reliability projects should similarly be expanded beyond the project's first year to reflect the present value of reduced or deferred future reliability investments.

In terms of additional benefits and costs to be estimated, we recommend that ERCOT: (1) modify its long-term market simulations to capture the impact of forced generation unit outages and ancillary service unit designations; (2) more fully estimate the reduced (or possibly increased) production costs due to project-related changes in transmission losses; (3) study the typical impact of transmission outages on project-related production cost savings to develop a multiplier that could be applied to standard estimates of production cost savings going forward; (4) similarly develop a multiplier to capture the disproportionately higher project-related benefits during weather-related spikes in peak loads; (5) modify simulations to more completely capture cost reductions (or increases) due to a project's impact on the operational cycling of power plants; (6) estimate any decreases (or increases) in installed capacity requirements due to changes in on-peak transmission losses; and (7) more fully consider emission-related costs (including for long-term risk mitigation benefits).

We further recommend that, at this point, the other benefits in Table ES-1 be considered, discussed, and analyzed only on a case-by-case basis for projects that are anticipated to offer significant value in terms of the individual benefit types. For example, an evaluation of generation cost savings may be undertaken in the future in the context of a transmission project that allows for either the deferral of generation investments (*e.g.*, by allowing plants in neighboring regions with surplus capacity to "switch" into ERCOT) or the development of new generating plants to be shifted from high-cost locations (*e.g.*, areas that have higher land costs or would require greater investment in emission controls) to lower-cost locations. Similarly, project-specific benefits should be evaluated on a case-by-case basis as future projects offer unique benefits, such as opportunities for improved utilization of transmission rights-of-way or the creation of low-cost options for possible future transmission projects.

To implement the recommended additional benefit metrics in the transmission planning process, it will be necessary to develop and refine proposed approaches through the Regional Planning Group (RPG) stakeholder process. We also anticipate that stakeholder workshops be used to fully explain the details of each proposed benefit metric and document with case studies how ERCOT has quantified its value. As ERCOT's experience with project-specific additional benefits metrics increases over time, these metrics should then be added to the set of metrics that is routinely considered.

4. Improve Use of Scenarios and Sensitivities

Recognizing the uncertainties about the future, particularly from a long-term perspective, we recommend that ERCOT improve its use of scenarios and sensitivities considered in the long-term planning process. Stakeholder feedback provided insight into the scenario-development process that had been undertaken in the last two years to create plausible and reasonable scenarios about future market conditions. Having made some significant progress, there are opportunities to meaningfully improve both the scenario development process and the usage of scenarios and sensitivities in the evaluation of project benefits and costs.

Further refining the stakeholder process is a key part of improving scenario development. It is clear that stakeholders will accept the results of long-term studies more readily if they understand the assumptions embodied in the scenarios and believe they reflect a reasonably complete range of plausible future market conditions. Building on the experience with ERCOT's recent scenario development effort, the next iteration of this process can be defined more clearly from the onset. ERCOT can specify more concisely how scenarios will be used in the long-term planning effort and how long-term planning results will be used in the RTP process. It is important for ERCOT to reiterate its invitation to all potentially interested parties to participate in this process and make clear that stakeholder buy-in for the scenario assumptions and planning effort will lead to "results that matter."

To achieve these goals, we recommend that the scenario development process be a facilitated stakeholder-driven process that includes representatives from each sector within the electric power industry as well as experts from outside of ERCOT and the power industry (such as from the oil and gas sectors) to share their views on the future of the state's economy and energy industry, including their perspectives regarding electricity usages and potential growth for the industry. The scenarios should reflect a wide range of plausible future outcomes in terms of ERCOT-wide and localized load growth, generation mix and locations, and fuel prices. The range in long-term values of economic transmission projects under the various scenarios should be used to assess the robustness of a project's cost effectiveness.

We recommend that short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive scenario definitions. Rather, such uncertainties should be simulated probabilistically or through sensitivity analyses for each of the chosen scenarios to capture the full range of societal value of transmission investments.

5. Enhance Economic Project and Benefits/Costs Identification Process

Finally, we recommend that ERCOT refine its process for identifying candidate economic transmission projects and the range of benefits specific to each project. We recommend that ERCOT consider establishing a structured process that allows market participants to propose candidate economic projects. Under this process, market participants would also need to identify the proposed projects' likely benefits and costs (consistent with the "checklist" provided in Table ES-1) and discuss (at least qualitatively) the possible magnitude of and why the project is expected to offer the identified benefits. It will be important that the initial list of benefits not be limited to ERCOT's analytical capabilities for estimating the magnitude of the benefits, but provide a comprehensive list of expected benefits regardless of modeling capabilities. Even if the value of some benefits is not easily estimated with existing tools, they should still be considered and at least be discussed qualitatively. Once proposed projects and their likely benefits have been specified, ERCOT can prioritize the proposed projects with stakeholder input and undertake benefit-cost analysis based on the available analytical capabilities to determine whether a proposed project meets its economic planning requirements.

I. INTRODUCTION AND BACKGROUND

The Electric Reliability Council of Texas (ERCOT) asked *The Brattle Group* (*Brattle*) to review the ERCOT process for screening economic transmission projects in the Long-Term Study (LTS) horizon, prepare recommendations on how to more completely estimate the economic value of transmission expansion from a societal perspective, and present to the ERCOT Long-Term Study Task Force (LTSTF) recommendations on how to improve its "Business Case" for transmission investment.

This effort specifically focused on reviewing ERCOT's existing 10-year Long-Term System Assessment (LTSA) methodology and its new scenario-based planning process that focuses on a 10- to 20-year time horizon and has been developed with the support of funding from the U.S. Department of Energy (DOE).

A. Background on ERCOT Transmission Planning

Transmission planning is a highly technical and relatively complex process that must consider a range of future uncertainties. ERCOT's existing planning process is undertaken over several time horizons to identify and approve new transmission investments required in the near-term to maintain system reliability and efficiency, and to evaluate upgrades that may be required in the long-term under different future states of the world. As part of its planning efforts, ERCOT produces planning reports focused on generation resource adequacy (Seasonal Assessment of Resource Adequacy and Capacity, Demand and Reserves Report), near-term transmission constraints and upgrades (Constraints and Needs Report and the Regional Transmission Plan), and long-term system resource needs analysis (Long-Term System Assessment).

Two stakeholder groups, the Regional Planning Group (RPG) and the LTSTF, support these efforts. As stated in its charter, "the RPG is a non-voting, consensus-based organization focused on identifying needs, identifying potential solutions, communicating varying viewpoints and reviewing analyses related to the transmission system in the planning horizon."[1] In contrast, the LTSTF provides the primary forum for discussion between representatives of appropriate state agencies, non-governmental organizations (NGOs), policy-makers, other planning stakeholders, and ERCOT regarding issues affecting long-range power system planning in the ERCOT Region and specific inputs, results, and feedback on long-term planning studies.[2]

Specific transmission projects are developed by ERCOT through its Regional Transmission Plan (RTP) process, in coordination with the RPG and Transmission Service Providers (TSPs). The

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1 ERCOT, 2012c.

2 See http://www.ercot.com/committees/other/lts/. The LTSTF is supported by the Scenario Development Working Group (SDWG), which provides the forum for discussions between these stakeholders and ERCOT regarding the development of scenarios to be studied as part of the Long-Term Study.

RTP—formerly called the Five-Year Transmission Plan (FYP)—has recently been expanded from a five-year horizon to assess transmission needs over a six-year horizon. Each year, the RTP is developed by ERCOT to address region-wide reliability and economic transmission needs.[3] Planned improvements to the ERCOT transmission system that will be reviewed for the RTP include:

- Projects previously approved by the ERCOT Board
- Projects previously reviewed by the RPG
- New projects that will be refined at the appropriate time by TSPs in order to complete RPG review
- Local projects currently planned by TSPs

For a new transmission project to be built in ERCOT, it must gain approval from the RPG through its tiered review approach that requires different levels of review depending on the size and cost of the project.[4]

The objective of the existing LTSA is to assess the potential needs of the ERCOT system ten years into the future. The LTSA is not used to recommend the construction of specific transmission projects. Instead, ERCOT uses the LTSA to evaluate possible system upgrades that may be required over the 10-year horizon. This long-term outlook is used to inform the 6-year planning effort undertaken through the RTP and RPG processes, and possibly to identify more options than the near-term upgrades specifically considered in the RTP context.

B. Motivation for Enhancement of Long Term Planning Process

The industry has increased its focus on evaluating the economic benefits of transmission investments in the transmission planning process. The evolving recognition that transmission investments can provide a wide range of economic benefits has often provided strong support for making certain transmission investments that serve more than meeting reliability requirements. Outside of ERCOT, the evaluation of economic benefits also in part has been motivated by regulatory requirements that the allocation of transmission costs be roughly commensurate with the benefits received from the investments.

ERCOT has recently increased its long-term transmission planning capabilities through a grant received from the U.S. Department of Energy. The purpose of the grant is to provide relevant and timely information on long-term system needs to inform near-term planning and policy decisions, to expand ERCOT long-term planning capabilities by developing new tools and processes to be used in future studies, and to facilitate enhanced input from stakeholders in the

[3] ERCOT, 2013a.

[4] For example, only transmission projects with capital costs greater than $15 million require a review by the ERCOT RPG.

long-term planning process.[5] At the time that our engagement started, ERCOT had already completed several objectives set out in the DOE grant through the LTS effort. Specifically, ERCOT had already:

- Developed a repeatable process to identify long-term reliability and economic efficiency system needs;
- Defined and studied one full spectrum of 10- to 20-year scenarios and resource portfolios;
- Used the long-term results to inform shorter-term studies with "least regrets" solutions across the scenarios as assumptions become more certain; and
- Implemented a tool and study framework for identifying ancillary service needs for increasing quantities of non-traditional resources.

In addition, ERCOT aimed to use the DOE grant to complete an additional analysis and stakeholder review to develop a process for assessing adequate and cost-effective transmission upgrades over the long term that will improve all transmission planning studies conducted by ERCOT.[6]

C. Objectives and Approach of Brattle Engagement

Our engagement to expand the economic evaluation capabilities of ERCOT's long-term planning efforts, funded by the DOE grant as well, comes at the end of the LTSA project. Our review consequently includes an assessment of many of the process improvements that have already been implemented by ERCOT under the grant. The specific focus of our work was to assess the evaluation criteria for economic transmission expansion used in the ERCOT long-term planning process and to recommend enhancements to the planning process and system modeling that will allow for a broader range of benefit metrics to be considered from a societal perspective. A better understanding of the benefits and costs of economic transmission projects is meant to allow ERCOT to improve its "business case" for new economic transmission projects. A clear understanding of and appreciation for these benefits and costs over the long term and a range of different future scenarios will also help to increase the robustness of transmission plans.

The aim of creating a "business case" for new economic transmission projects reflects the fact that, historically, transmission projects have been evaluated and designed based on engineering criteria with the primary goal of maintaining system reliability. However, transmission investments provide a wide range of societal value beyond system reliability. Currently, the lack of a process that can identify and analyze a broad range of those benefits in the context of long-term planning limits the evaluations of transmission projects to only capturing a portion of the

5 ERCOT, 2011b, p. 1.

6 *Id.*, p. 21.

overall economic benefits and thereby inadequately considering the long-term value that beneficial transmission investments offer. Transmission planning is a complex effort defined both by high-level objectives and detailed analytical efforts. For these reasons, identifying potential process improvements requires a detailed evaluation of the long-term transmission planning process at several levels, in terms of both improving the process and broadening its scope. As summarized in Table 1, we have focused our review and recommendation to address each of the following four dimensions of transmission planning: (1) effective high-level study objectives; (2) repeatable execution of specific process steps; (3) reliable application of analytical tools; and (4) understandable and consistent use of analytical results.

Table 1
Approach to Long Term Study Review

	Assess and Improve the Process for the Existing Planning Scope	**Broaden the Scope to More Effectively Identify Projects with Net Benefits**
1. Study Plan (objectives and high-level concepts)	- Identify limitations of scope of benefits quantified and project evaluation criteria	- Add benefit categories and metrics - Describe how study scope could be improved - Suggest enhancements to project evaluation criteria

2. Process Steps	- Identify opportunities for improving and streamlining the process
	- Will be informed by an assessment of effort and value, and comparison to processes we've done/seen
	- Clarify process/stakeholder input for identifying promising projects and their likely benefit categories
		- Identify aspects that can be readily added to existing modeling system
		- How to evaluate benefits that can not be captured in existing modeling system
		- For additions that may be a more major effort:
		  - Develop potential process modifications
		  - Identify ways to streamline (e.g., apply selectively or to a portfolio; develop generic benefit multipliers)

3. Modeling Tools, Execution, and Quality Control Practices	- Identify specific improvement opportunities for:
	  - model calibration
	  - quality control (diagnostics and review)
	  - data and case management
	  - automation of repeated processes
	  - documentation of modeling steps
	  - staff training
		- What are best practices and training needs for successfully executing new steps/tools?

4. What to do with the Results		- Identify ways to integrate LT planning better with actionable near-term planning (e.g., by merging models and including LT NPV in near-term study)

In this effort of evaluating ERCOT's existing long-term transmission planning process and identifying possible improvements to scope, process, modeling, and utilization of results, our team completed the following tasks:

1. Reviewed ERCOT's long-term transmission planning scope and process
2. Solicited ERCOT stakeholder input
3. Reviewed ERCOT's modeling infrastructure and process

4. Identified additional benefit metrics for valuing additional (non-conventional) transmission-related societal benefits and worked with ERCOT to develop case studies for evaluating the benefits
5. Developed recommendations to: (a) improve ERCOT's transmission planning process for economic projects; (b) enhance its modeling infrastructure and practices; and (c) increase the scope of economic benefits through additional benefit metrics that should be considered in ERCOT's planning process
6. Presented findings and recommendations to ERCOT staff and ERCOT stakeholders.

The remainder of this report documents our efforts along each of these tasks. Section II provides a more detailed discussion of ERCOT's Long-Term Transmission Planning process. Section III summarizes stakeholder comments regarding the long-term planning process and presents a subset of our recommendations based on that stakeholder feedback. Section IV summarizes our review of and recommendations concerning ERCOT's modeling infrastructure and practices. Section V explores additional benefit metrics for valuing additional (non-conventional) transmission-related societal benefits for possible consideration in ERCOT's transmission planning process and identifies and discusses the benefits and metrics we recommend ERCOT implement in either the near-term or over time as project-specific needs or opportunities arise. And, finally, Section VI presents our recommended improvements for the ERCOT's overall transmission planning process and project selection criteria.

Additional detail is presented in four appendices. Appendix A – Types of Transmission Benefits and the Importance to Consider a Complete Set Of Benefits; Appendix B – Experience with Identifying and Analyzing a Broad Range of Transmission Benefits; Appendix C – Overall Societal Benefits Distinguished from Benefits to Electricity Customers; Appendix D lists the stakeholder entities who provided feedback (a) on ERCOT's long-term transmission planning process during interviews conducted in April 2013; and (b) in response to the draft recommendations we presented during the June 3, 2013 stakeholder meeting; and finally, Appendix E contains the slides from the June 3, 2013 stakeholder meeting during which we presented the findings and draft recommendations of our review effort.

II. ERCOT LONG TERM TRANSMISSION PLANNING

As previously noted, ERCOT's transmission planning process considers two different timeframes. A six year transmission plan called the Regional Transmission Plan (RTP) identifies actionable projects that are usually necessary to meet reliability needs and evaluates near-term economic opportunities. The Long-Term Plan addresses long-term opportunities that might improve on shorter-term plans.

> [It] evaluate[s] the system upgrades that are indicated under each of a wide variety of scenarios in order to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined

considering only near-term needs in the Five-Year Transmission Plan development.[7]

Transmission planning in ERCOT is a stakeholder-driven process. ERCOT holds monthly RPG meetings with stakeholders to review the progress being made by ERCOT staff and external consultants towards developing future transmission plans or to refine the planning process. With the expansion of the long term study, joint RPG and LTSTF stakeholder meetings have been held to provide updates of ERCOT analyses specifically on the effort to expand the scope of the long-term study process. The topics discussed during the joint meetings have included future scenario definitions and development, additional modeling tools development, review of scenario-specific intermediate results, such as generation resource plans for each scenario, and review of the final results of the economic analysis.

The joint RPG/LTSTF meetings have provided a forum for ERCOT to receive input from stakeholders on a range of issues related to planning the ERCOT system over the long term.[8] ERCOT explicitly requests that stakeholders provide input following the meetings to ensure that all comments can be considered.

Based on the work of ERCOT and stakeholder through this process, the scenarios used in the 2012 Long Term System Assessment included[9]:

- Business as Usual with All Technologies (BAU All Tech)
- BAU All Tech with Retirements
- BAU All Tech with Updated Wind Shapes
- Extended Drought
- BAU All Tech with High Natural Gas Price
- Environmental

The 2012 scenario development effort focused especially on the Extended Drought scenario and on load growth forecasts. The Extended Drought scenario required modeling by Sandia National Labs and Black & Veatch of the possible conditions that the ERCOT region may face if the drought of 2011 was sustained over a longer time period. The scenario provided a better understanding of the impacts of a drought.[10] Discussions during the 2012 effort also focused on how the load forecast accounts for unexpected growth from expanding oil and gas sector activities. ERCOT has traditionally used non-farm employment data to forecast future loads, but

7 ERCOT, 2012d, p. 6.

8 Two additional working groups—the Demand Side Working Group and the Emerging Technology Working Group—have provided forums for stakeholders to include in these specific topics.

9 ERCOT, 2012d.

10 ERCOT, 2012a.

stakeholders voiced concern that it may not properly account for the oil and gas development currently occurring.[11]

The scenarios developed through the stakeholder process provide a range of assumptions about possible futures that are used for analyzing the ERCOT system over the next twenty years. The range of scenarios considered is summarized in in Table 2.[12] As shown, the scenarios differ in the generation and demand technologies considered, weather, natural gas prices, continuation of the wind production tax credit (PTC), and emissions costs.

Table 2
ERCOT LTS Scenario Definitions

Scenario	Technology	MW	Demand Repsonse	Moody's employment	Weather	Gas Price	PTC Continuation	EMISSION COSTS	Other Policies
S0 Business As Usual	Combined Cycle	10,800	0	Base	Normal	EIA Reference	No	No	
	Combustion Turbine	5,700							
	Wind								
	Solar								
	Admin CT								
S1 Business as Usual All Technologies	Combined Cycle	13,200	Up to 2,700	Base	Normal	EIA Reference	No	No	
	Combustion Turbine	7,400							
	Wind								
	Solar								
	Admin CT								
S2 Business as Usual All Technologies, updated wind Natural Gas Retirements > 50yrs	Combined Cycle	8,500	Up to 2,700	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	19,700							
	Wind	1,500							
	Solar	10,000							
	Admin CT	13,770							
S3 Business as Usual All Technologies Updated Wind	Combined Cycle	3,600	Up to 2,700	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	7,140							
	Wind	17,151							
	Solar	10,000							
	Admin CT	17,850							
S6 Business as Usual All Technologies Continuation of PTC	Geothermal	3,600	4,500	Base	Normal	EIA Reference	YES	No	
	Combustion Turbine								
	Wind	23,365							
	Solar	11,000							
	Admin CT								
S7 Business as Usual High Natural Gas Price	Combined Cycle		Up to 2,700	Base	Normal	EIA + $5	YES	No	
	Combustion Turbine	400							
	Wind	35,975							
	Solar	13,000							
	Admin CT	2							
S9 Business as Usual All Technologies Increased Asynchronus Tie Capability	Combined Cycle	8,400	2,500	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	680							
	Wind	28,546							
	Solar	7,500							
	Admin CT	27,540							
S5 Drought	Combined Cycle	3600 / 4400 /10400	A-1000 B-2000 C-NA	Base	2011 Summer	A EIA Ref B EIA - $2 C-EIA Ref	A - No PTC B - PTC C- PTC	A - No B- Yes C- PTC	Water Costs added to New Thermal
	Combustion Turbine	13090 / 15295 / 170							Reduced HSL due to Hi Ambient Temp
	Wind	13031 / 5500 / 68100							
	Geothermal	3600 / 1700 / 3600							
	Solar	11000 / 9000 / 7500							
	Admin CT	16490 / 15293 / 29410							
S8 Environmental	Combined Cycle	2,890	2,000	Base	Normal	EIA + $5	YES	Yes	Cross State Air Polution
	Combustion Turbine	70,464							MATS / NESHAPS
	Wind	18,000							No new pulverized coal
	Geothermal	3,600							
	Solar	18,000							IGCC Only
	Admin CT	32470							
S4 Environmental With Demand Response and Energy Efficiency	Geothermal	3600	37,451	Base	Normal	EIA + $5	YES	Yes	10,000MW Demand Response Mandate
	Wind	51211							15% of Energy by 2025 from Energy Eff
	Admin CT	4350							

11 ERCOT, 2012b.

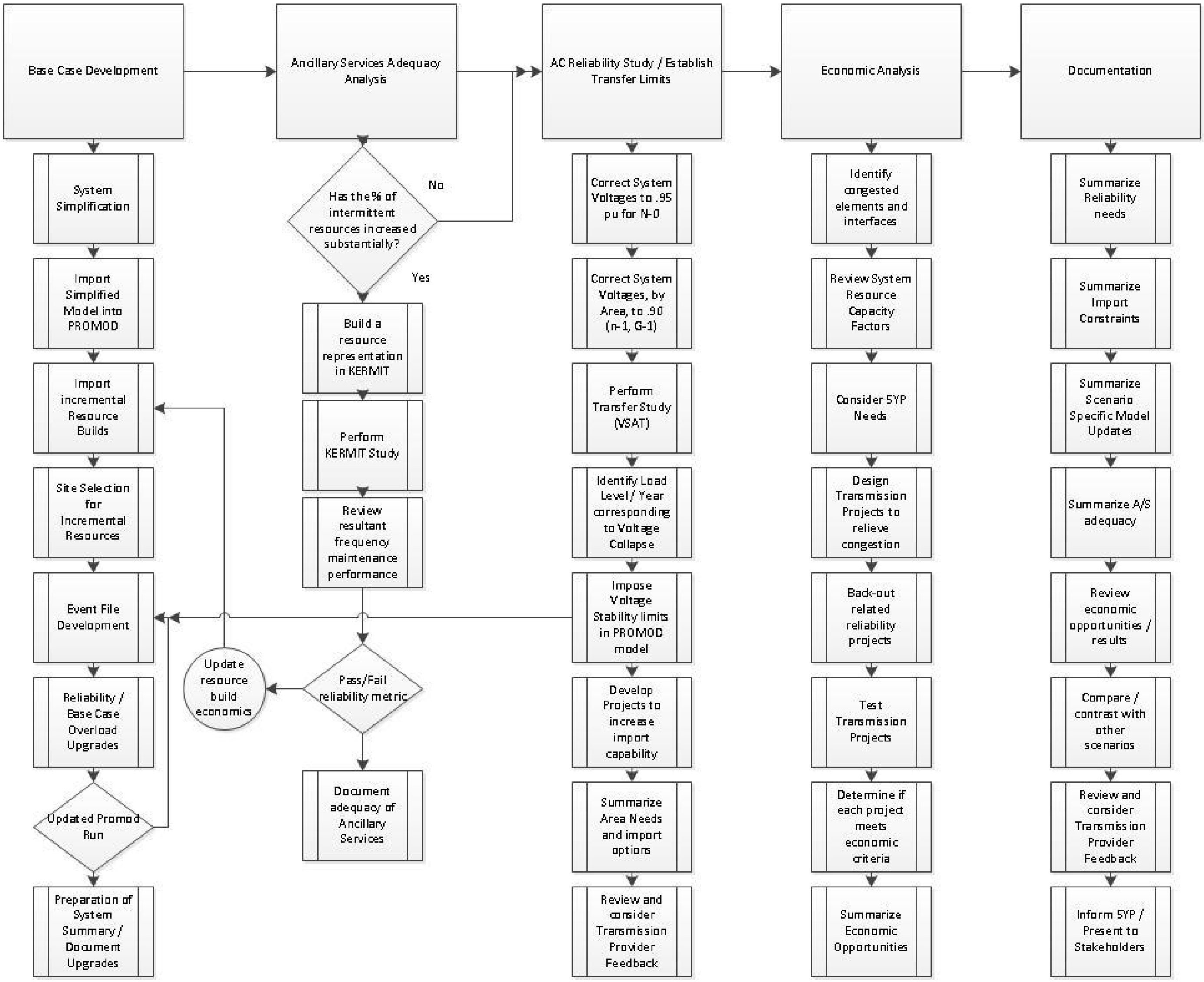
12 ERCOT, 2013b.

Based on these scenario assumptions and their impacts on expected future load and generation capacity, the ERCOT long-term modeling team developed a process for evaluating transmission needs. Each scenario is analyzed through five major steps, as shown in Figure 1.[13]

For each scenario, a Base Case is developed in the first three steps of the process which identifies generation and reliability-driven transmission additions to the current system before considering new economic transmission projects. To do so, the transmission system is simplified in Step 1 by removing 69 kV and radial 138 kV lines, and incremental generation is added through a process that identifies the specific locations in which the plants are projected to be built. This Base Case is then analyzed for selected individual years to identify necessary reliability-driven transmission upgrades. Steps 2 and 3 then further modify the Base Case to ensure operational requirements are met for each study year. This involves analyzing ancillary service adequacy (Step 2) and alternating current (AC) reliability and stability-based transfer limits (Step 3).

13 *Id.*

Figure 1
ERCOT Long Term Transmission Planning Modeling Process



An important step in the process of developing the Base Case is adding new resources to meet the projected future load. ERCOT completes an analysis of where and when future resources will most likely be added in order to then plan the future transmission system. As an example, the resource expansion results from Steps 1–3 of the Base Case analysis are summarized in Table 3[14] for the "Business As Usual (BAU) with All Technologies" scenario.[15]

[14] ERCOT, 2012d. Appendix 4, p. 1.

Table 3
BAU with All Technologies – Resource Expansion Analysis Results

Description	Units	2014	2017	2020	2023	2026	2029	2032
CC Adds	MW	-	400	800	3,200	2,800	2,400	3,600
CT Adds	MW	-	700	3,100	800	600	1,300	900
Coal Adds	MW	-	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-	-
Solar Adds	MW	-	-	-	-	-	-	-
Wind Adds	MW	-	-	-	-	-	-	-
Annual Capacity Additions	MW	-	1,100	3,900	4,000	3,400	3,700	4,500
Cumulative Capacity Additions	MW	-	1,100	5,000	9,000	12,400	16,100	20,600
Retirements	MW	-	-	-	-	-	-	-
Residential Demand Response	MW	-	2,200	2,200	2,200	2,200	2,200	2,200
Industrial Demand Response	MW	500	500	500	500	500	500	500
Reserve Margin	%	8.32	2.80	2.79	3.04	2.89	2.39	1.33
Coincident Peak	MW	74,148	81,316	85,114	88,805	92,234	96,276	100,744
Average LMP	$/MWh	34.73	55.97	61.88	69.49	77.66	83.06	94.11
Natural Gas Price	$/mmbtu	4.32	4.77	5.42	6.44	7.36	8.00	9.19
Average Market Heat Rate	MMbtu/MWh	8.04	11.73	11.42	10.79	10.55	10.38	10.24
Natural Gas Generation	%	41.3	46.4	48.6	50.4	52.2	54.0	56.1
Coal Generation	%	36.0	33.2	32.0	30.7	29.6	28.4	27.3
Wind Generation	%	10.3	9.0	8.6	8.3	8.0	7.7	7.4
Scarcity Hours	HRS	-	17	17	16	20	21	21
Unserved Energy	GWhs	-	29.9	22.0	38.2	40.3	42.7	59.5
SO2	Tons	354,033	354,439	357,113	356,594	356,561	356,502	357,857
CO2	(k) Tons	229,961	247,892	251,225	264,772	272,112	280,358	290,395
NOx	Tons	129,480	138,280	139,958	143,322	143,939	145,780	148,097

Once Base Cases have been developed for the selected study years that include all generation resources and necessary reliability-driven transmission upgrades, ERCOT completes an Economic Analysis (Step 4) in which potential economic transmission projects are identified by reviewing congested elements and interfaces, reviewing system resource capacity factors, and considering needs identified in the near term analysis. ERCOT also provides an opportunity for stakeholders to suggest potential economic projects for consideration.

Once identified, the economic transmission projects are added to the Base Case (defining a "Change Case") to determine the production cost savings that would be realized in the study year, which represents the assumed first year of the new line's operations. These production cost savings are estimated as the difference between simulated production cost savings in the Change

[15] The results of the Business As Usual with All Technologies scenario are provided here to demonstrate the ERCOT transmission planning process as it provides the base projections that ERCOT developed to use in its long-term transmission modeling for one of the long-term scenarios. Several of the other scenarios are variations based on adjustments to this scenario.

Case and the Base Case. In addition, ERCOT analyzes whether the economic project can defer or avoid any of the reliability projects previously added to the Base Case in the particular study year.

To determine whether economic transmission projects are cost effective, ERCOT compares the net costs of the economic project (net of the costs of the avoided or deferred reliability projects) for the study year to the benefits estimated through the production cost simulations for the same year. Economic projects are determined to pass the economic criteria if the first year revenue requirement for the adjusted capital costs of the economic projects is greater than the first year production cost savings of the economic transmission project. Consistent with Public Utility Commission of Texas (PUCT) orders, ERCOT approximates first-year revenue requirement by assuming that it is 1/6 of the projects' capital costs.

As an example, the results of this economic analysis for the "BAU with All Technologies" scenario are summarized in Table 4.[16] As shown in this example, only one minor economic project, the upgrade of the Green Bayou 345/138 kV line, was found to be economic.

Table 4
BAU with All Technologies – Economic Results

Tested Project	Capital cost	Reliability benefit	Adjusted Capital Cost for Reliability Benefit	Production Cost Savings	1/6 of Adjusted Capital Cost	Meet ERCOT Economic Criteria?
Watermill-Navarro	150.2	-67.0	217.2	0.2	36.2	No
Fayette-O Brien	241.7	-108.8	132.9	0.6	22.2	No
Lufkin-Jordan	430.2	36.7	466.9	4.1	77.8	No
TNP One-Salem-Zenith	444.6	-105.3	339.3	6.2	56.6	No
Upgrade Gibbons Creek-Singleton	23.8	n/a	n/a	0.5	4.0	No
Upgrade Green Bayou 345/138 kV	11.9	n/a	n/a	2.8	2.0	Yes
Upgrade S. Texas-Hillje, and Hillje-O'Brien	254	-54.1	199.9	4.1	33.3	No
Cagnon-Miguel	193.3	87.4	280.7	3	46.8	No
Cagnon-Miguel & Cagnon 345/138 kV	217.1	n/a	n/a	4.5	36.2	No
Cagnon-Pawnee	241.7	137.3	379.0	3.7	63.2	No
Cagnon-Pawnee & Cagnon 345/138 kV	265.4	n/a	n/a	4.9	44.2	No
Kendall-Hill Country	145	n/a	n/a	-8.2	24.2	No
Upgrade Elgin-Taylor	15.3	n/a	n/a	1	2.6	No
Upgrade Hill Country-Sky	30.3	n/a	n/a	1.2	5.1	No

16 ERCOT, 2012d. Appendix 5, p. 5.

The long-term study results are presented at monthly RPG meetings as they are developed. They are then summarized in ERCOT's annual Long-Term System Assessment. As stated above, the goal of the LTSA is to inform participants in the transmission planning process of potential economic transmission lines that are robust across scenarios. The potential projects identified in the LTSA may subsequently be considered in the (near-term) RTP process, when more information is available about future market conditions. In addition, the LTSA results may not be project-specific but, instead, provide information about areas where transmission upgrades may be economically efficient in the future. For example, the 2012 LTSA concluded that "the Houston Region will need at least one additional import path within the next ten years."[17]

[17] *Id.,* p. 42.

III. STAKEHOLDER COMMENTS REGARDING THE LONG TERM PLANNING PROCESS

Stakeholder involvement is critically important to the success of long term transmission planning. Therefore we have engaged stakeholders throughout our evaluation process, including (1) conducting an initial kickoff meeting to the RPG, (2) interviewing stakeholders, (3) presenting our draft recommendations at a stakeholder meeting, and (4) collecting stakeholders' feedback on our recommendations.

During the kickoff meeting we presented our proposed approach and requested opportunities to discuss the details with stakeholders who were willing to be interviewed. We then interviewed every stakeholder who had indicated an interest to speak with us, including representatives from utilities, transmission developers, generators, industrial consumers, landowners, market analysts, and the ERCOT Independent Market Monitor.

Our goal in interviewing stakeholders was to better understand the stakeholders' views on:

- The existing long term study planning process and assumptions;
- The role and effectiveness of the long term study in the overall transmission planning process;
- The role of transmission owners and other stakeholders in the process;
- The benefits of transmission; and
- Other areas of concern for each stakeholder.

We received a wide range of viewpoints from different stakeholders during the interviews and have included our summary of their specific comments here without attribution to specific stakeholders. We have also considered these viewpoints in providing our recommendations to ERCOT.

A. SUMMARY OF STAKEHOLDER COMMENTS

Purpose and Value of Long-Term Planning

Overall, stakeholders generally were appreciative of the efforts being made by ERCOT to plan the transmission system beyond the near term and a subset of stakeholders felt there was significant value in ERCOT conducting long-term studies to inform transmission planning and have expressed hope that as ERCOT and stakeholders become more familiar with the new process, the long-term nature of the process will enhance planning over time. However, some stakeholders expressed concerns about the usefulness and effectiveness of the current process for implementing long-term planning, including a subset of stakeholders who questioned the need for long-term analyses at all, given the significant uncertainties in the outer years and the fact that the needed transmission can be built relatively quickly (*i.e.*, within the near-term planning time frame) in Texas. We attribute the concerns about the usefulness and effectiveness to the lack of clarity around how the results would be used.

Overall, stakeholder viewpoints are quite diverse and we summarize them below:

- A stakeholder highlighted the fact that the LTSA **process is relatively new and it is a good start** for examining the transmission needs in ERCOT from a long-term perspective. Because of uncertainties about the future, any such long-term perspective needs to include the use of scenario-based planning. While not aligned with all stakeholders' own perspectives about the future, the current effort begins to lay out a foundation from which the planning processes and scenario development can be improved over time.

- Some stakeholders support having a long-term planning process that allows planners to **look at larger projects** instead of simply relying on incremental, reliability-based builds and to include long-term benefits when making decision about projects.

- Some have suggested that it would be valuable for ERCOT to **aggregate all the issues** that ERCOT is trying to solve with transmission and allow stakeholders and transmission developers to propose solutions.

- Most, but not all, stakeholders believe that there **could be significant value** in conducting the long-term planning, particularly in the context of discussing what the grid would need in the long term.

- Some stakeholders believe the long-term study should serve as a basis for establishing **long-term benefits for various transmission projects** and that it may be particularly helpful when comparing more expensive solutions that can provide greater long-term benefits against cheaper solutions that focus primarily on the short-term issues.

- Several stakeholders recognized that the LTSA provides valuable information on long-term benefits when deciding between short-term and longer-term alternatives. It **should thus generate conceptual projects that can be studied further** as different future scenarios play out.

- Many stakeholders acknowledge the value of looking beyond five years to develop the economic projects, but some stakeholders have expressed concern that the estimated future market conditions, generation development, and **transmission benefits in the outer years (20 years) may be too uncertain or speculative** to be useful for transmission planning.

- Some stakeholders suggested **reducing the long-term planning timeframe to 10–15 years** instead of the 20 years currently used.

- A stakeholder expressed a strong preference for using only the short-term RTP process for transmission planning and believes **looking out further is not necessary** for ERCOT since many projects resulting from the short-term planning process have been built already and the 20-year long-term planning process **relies too heavily on projecting uncertain futures,** particularly since constructing transmission can be done relatively quickly in Texas.

- Some stakeholders have expressed the concern that the information used in the LTSA is not considered in the short-term planning and, consequently, **does not affect the proposed actionable projects**.

- Several stakeholders have expressed concerns that the planning process only yields local reliability-based transmission projects for which incumbent utilities have the right-of-first-refusal to build, **limiting the involvement of independent developers**.

- A stakeholder pointed out that critical reliability projects seem to be a priority in the permitting process in Texas as those projects are faster to approve than longer-term projects. The combined effects of focusing primarily on reliability projects and a shorter permitting process for those projects tend to result in **ERCOT continually developing only reliability-based projects** after they become "critical."

- Some have expressed their understanding that the LTSA is simply a screening tool for projects to assess future grid issues and uncertainties and not to produce specific projects to be developed. With this understanding, some suggested that perhaps the **long-term plan could yield projects that can be studied in future short-term plans** as scenarios play out.

- One stakeholder believes the transmission planning process has provided too many out-of-market incentives for developing emerging technologies and that ERCOT is becoming a facilitator or even a promoter of new technologies. Instead, ERCOT should **focus more on interconnecting generators** than on the longer-term and speculative needs of the system.

- A stakeholder is concerned that ERCOT appears to favor transmission investments that are paid for by ratepayers over generation solutions.

Scenarios Development and Associated Results

Many stakeholders showed particular interest in the future scenarios that were developed to inform the long-term transmission planning effort and appreciated that the process was driven by stakeholder involvement. Some were concerned that many of the chosen scenarios may be unrealistic and that their input was not fully considered. Stakeholders consistently commented that the results of future long-term studies will only be accepted if a wide range of stakeholders believe that the scenarios and associated inputs are reasonable. There was general agreement that the current scenarios will need to be refined further and that increased stakeholder engagement will be needed to ensure consistent understanding and "buy-in" to the long-term planning results. Some stakeholders thought the scenarios were too similar and recommended that a more divergent set of scenarios be developed to help identify weaknesses in the transmission system and to allow for the development of a more robust transmission grid.

- Some stakeholders believe that the **long-term planning process is an effective way to address a large number of planning challenges** such as resource alternatives, carbon policies, and future generation locations, and it provides an opportunity for stakeholder input to these system issues.

- Some stakeholders are generally satisfied with the range of scenarios used in the long-term planning process, particularly because they were the result of the stakeholder process.

- Some believe that it is **very important to obtain stakeholder buy-in** from the very beginning of the process of defining credible scenarios

- It is also important to **obtain buy-in from both the ERCOT Board and the Public Utility Commission** from an early stage of the long-term planning process.

- Some stakeholders believe that the future scenarios used in the long-term planning process **need to be more realistic** and that it is extremely important that there is an avenue for the stakeholders to discuss scenarios, inputs, and sensitivities

- Some have expressed the concern that the current long-term planning process **is not linked to ERCOT's strategic planning** process.

- Some stakeholders emphasized that it is **very difficult to forecast load and particularly generation developments that far into the future**.

- Some expressed the concern that the **scenarios currently used are too similar** and therefore do not yet capture the potential future uncertainties or the transmission options to address future needs.

- Some stakeholders have expressed **concern about the credibility of the scenarios** and if the scenarios employed in the long-term planning process are not credible to the stakeholders, then the results would not be meaningful enough to affect transmission planning in the near-term.

- Some stakeholders are particularly concerned that the **scenarios do not capture the full breadth of uncertainties and possible future outcomes**. Some stakeholders strongly recommend that more “stress scenarios” be explored to identify system weaknesses and solutions that lead to a more robust transmission grid.

- Some suggested that for the long-term planning process to be effective, it should **provide a more visionary look at the future**, with input from a wider range of stakeholders (*e.g.*, legislators, industrial customers, the oil and gas industry), to develop a wider range of possible, even extreme scenarios.

- Several stakeholders have expressed a strong impression that the scenarios and proposed solutions **do not yet incorporate the knowledge of those who know their local system** the best, including load growth on their systems and the feasibility of certain proposed projects. Some have suggested that ERCOT should build bottom-up long-term load forecasts incorporating the information that local utilities have.

- Some have expressed the concern that the scenarios incorporate very specific assumptions about the location of load and generation and that even **a slight change in locational load or generation would lead to very different transmission solutions**. This could lead to some degree of lack of support for the scenarios and associated transmission solutions.

- Some stakeholders suggested that the cost of **developing conventional generation in different locations should be studied more thoroughly** and that low-cost locations be considered in long-term transmission planning, similar to the wind zones considered in the CREZ process.

Level of Stakeholder Involvement

Most stakeholders expressed considerable interest in continued involvement in long term planning, especially in the development of scenarios and in reviewing results. Several stakeholders hoped that ERCOT would more deliberately incorporate input from transmission owners with specific local knowledge. A few stakeholders expressed concerns about their ability to be involved in the process due to the highly technical nature of the discussions, the significant commitment of time and resources needed for participation, and the currently limited use of long-term study results.

- Most but not all stakeholders **appreciate the special effort ERCOT** has made to invite and welcome input and feedback from stakeholders.

- Some stakeholders believe that the first cycle of LTSA has already worked through a lot of key issues and **has laid a good groundwork for future iterations** and improvements to the planning process.

- Some of the transmission owners feel that **ERCOT could rely more on their local expertise** in the long-term planning efforts.
- Some of the non-technical stakeholders **find it difficult to participate in a technically challenging process** where they have limited capabilities to understand the process, limited information available to them, and limited assurance that their concerns are being represented by either ERCOT or the Public Utility Commission.
- Some wanted to know **how to become more involved** in the overall planning process so that they are not surprised with the results.
- Some stakeholders suggest that ERCOT **be more open to allowing parties to participate as stakeholders** and to find ways to ensure that stakeholders have sufficient time to review and react to proposals made by ERCOT.

The Scope of Transmission Benefits Considered

Many stakeholders were receptive to considering additional categories of benefits in the transmission planning process. Some stakeholders expressed that transmission investments offer many benefits that should be, but have not yet been, considered in ERCOT's planning process. In contrast, some are concerned that considering additional benefits will lead to an increase in unnecessary transmission build-out that could adversely affect electricity customers, land owners, and possibly other market participants. A few stakeholders also suggested broadening the scope of costs considered in the long-term study process, such as the costs of balancing the intermittent resources that are facilitated by new transmission lines and the cost associated with lost land value. Several stakeholders also suggested that ERCOT and the PUCT consider electricity customer benefits metrics in addition to relying solely on societal benefits.

- Some stakeholders **would like to see projects that provide benefits to electric customers,** rather than being limited by a narrowly-defined "societal" perspective.
- Some stakeholders expressed that, even if not used to make project decisions, the **benefits of transmission *to customers*** should be made clear.
- On the other hand, some stakeholders want to **make sure that only societal benefits** are considered.
- Some stakeholders expressed the view that ERCOT's **current planning process and market simulation assumptions substantially understate transmission-related benefits**. Specifically, some have indicated that both near-term and long-term planning significantly understate transmission-related benefits by not adequately considering: load uncertainty, generation outages/availability, planned and forced transmission outages, fuel price volatility, real-world ancillary service procurement and generation

commitment, actual operational transmission limits that are well below simulated limits, uncertainty in wind generation, and possible future changes in environmental regulations.

- Some believe that **transmission can help increase market competition and liquidity** and therefore should be considered in the benefits metrics; however it is unclear how much of an impact it would have in ERCOT considering that market power is mitigated.

- Some stakeholders have expressed a **concern that costs and benefits carry different degree of uncertainties** and such differences should be reflected in the analysis.

- Other stakeholders are **concerned that consideration of a more expansive set of benefits, particularly over the long term, will result in overbuilding transmission**. They suggest that long-term costs (such as those associated with renewable integration, lost right-of-way, degradation of land value, and associated environmental impacts) should be considered as well.

- Some have expressed a **concern that the existing benefit-to-cost test sets an artificially high hurdle**.

Other Feedback

- Some stakeholders would like the **results of the ERCOT analyses to be better communicated**, preferably in layman's terms, and to make sense and be meaningful and practical, despite all the complex modeling processes used.

- A stakeholder believes that although ERCOT shares results with Transmission Service Providers (TSPs) prior to the Regional Planning Group, they **do not have enough time to provide constructive input**.

- Some stakeholders expressed that they are **not sure how to propose new project ideas without giving away confidential information** to potential competitors.

- Some expressed the **importance of non-transmission alternatives** and noted that ERCOT currently does not have a process that considers those alternatives before deciding on a transmission project.

- Some stakeholders expressed **the need for high-level leadership to drive change** in the ERCOT process and to educate the Board and Commission on the legitimacy of the approach.

B. RECOMMENDATIONS BASED ON STAKEHOLDER COMMENTS

Based on our interviews and the comments of ERCOT transmission planning stakeholders, we believe ERCOT has an opportunity to increase stakeholder participation and, in doing so, improve the transmission planning process. We recommend:

- ERCOT should **sharpen the goal definition of Long-Term Planning and establish how results generated through Long-Term Planning will influence "actionable" Regional Transmission Plans.** We recommend that, as ERCOT refines the long-term planning process, specific processes and communications are put into place to ensure that "results matter" and stakeholders understand how they matter. This will require that ERCOT articulate how the long term planning results will be used in the RTP in a more formalized manner.

- ERCOT should **reiterate their invitation to all potentially interested parties to participate in the stakeholder processes** and increase the level of stakeholder engagement and comfort. This could be accomplished by placing more attention on developing the scenarios and obtaining a more wide-spread buy-in from stakeholders about the assumptions and scenarios. Even if not everyone agrees to the assumptions and scenarios, ERCOT should increase stakeholder engagement in their development. Further, local system knowledge should be considered or solicited more actively when developing project ideas.

- ERCOT should put into place specific processes to ensure that the results of the long-term planning are trusted by stakeholders. This can be accomplished by **conducting a workshop on scenario development that will involve stakeholder representatives** from each sector within the electric power industry and experts from outside of ERCOT and the power industry to share views of the future and document the collective results from the scenarios developed.

- ERCOT should **ensure that scenarios developed by the stakeholders are well documented**, shared with all stakeholders, and understood.

- ERCOT should **clarify for its stakeholders the types of transmission benefits and costs considered** in its analysis by conducting special workshops that focus on stakeholders gaining a detailed understanding of all the benefit metrics and how the benefits will be compared to the costs.

IV. REVIEW OF ERCOT'S MODELING PRACTICES AND INFRASTRUCTURE

As part of our assessment of how to identify economic transmission projects more effectively within ERCOT's long-term planning process, we interviewed ERCOT modeling staff and reviewed their documentation. Our objective was to identify opportunities for improving the modeling process steps, refining the modeling execution practices, and training ERCOT staff (if needed) on how to evaluate the types of transmission benefits already included within the current LTS scope. Such improvements were intended to complement the expansion of benefit categories addressed in Section V and the enhancement of evaluation criteria discussed in Section VI.

This section of our report summarizes our model-related findings and recommendations for ERCOT to consider. We first provide a short description of how we conducted our assessment, followed by a summary of both what is working well and where there are areas for improvement. Finally, we present for further consideration by ERCOT our recommendations related to ERCOT's modeling team and practices.

A. How we conducted our assessment

The starting point for our assessment was ERCOT's existing documentation of its modeling processes. The most important documents we reviewed were: ERCOT's "Long Term Study – Transmission Analysis" (version 1.0); "Long-Term System Assessment for the ERCOT Region," (Dec. 2012); ERCOT's "2012 Five-Year Transmission Plan Study Scope and Process"; and "Transmission Needs Analysis Scenario 2/3 Update," (Oct. 12, 2012). We also reviewed sample results from the long-term (LT) group's PROMOD IV simulations.

After reviewing ERCOT's documentation of its modeling practices, we conducted interviews with each of ERCOT's three modeling groups: the LT, the mid-term (MT), and resource adequacy (RA) groups. The interviews were conducted via conference calls—two rounds for each group, plus additional follow-up calls.

B. What is Working Well in the Modeling Process

Overall, we found that ERCOT's modeling processes are well designed and documented, and the modeling team members demonstrated strong expertise in transmission and economic modeling, with no identified need for additional market simulation training.

Several modeling techniques used by ERCOT are best-in-class. An example is ERCOT's methodology for adding future generation to the model where most economic (considering factors such as environmental siting challenges in load pockets, fuel supply, and locational market prices, or LMPs)—although the process should continue to evolve to consider improved estimates of locational cost differences and the indirect costs that certain resources (such as intermittent generation) impose on the system. Similarly outstanding is the teams' use of transmission reliability models alongside economic models. For example, within each scenario, ERCOT's modeling approach identifies reliability needs before evaluating the economics of new transmission that could be added to the already-reliable Base Case, sometimes avoiding the need for reliability upgrades. The teams also make sure they are modeling transmission constraints (including contingencies and voltage-limited interfaces) properly in each case they run, especially when modeling major additions of resources or transmission. These practices help capture shifts in congestion patterns that are important for assessing transmission benefits.

We found that all team members demonstrate strong expertise in transmission and economic modeling, and a sound understanding of how the economic and reliability models can interact. The staff has considerable accumulated experience from recent studies and prior work; and with their growing experience with the long-term planning process, they will likely be able to execute future studies even more smoothly than the current set of initial studies. Team members would not need any additional training, except as needed to expand the scope of benefit categories evaluated (see Section V) and to enhance the criteria used to evaluate transmission projects (see Section VI).

Finally, we found that the modeling team has been clearly documenting its process steps. The prepared documentation is thorough and makes use of well-constructed flow charts and maps. The LTSA report and RPG presentation materials provide many good examples of such documentation.

C. Recommendations for Possible Improvement

We identified three general areas where current practices may not support the transmission planning process as effectively as they could. These areas are summarized briefly below and then are discussed more extensively in the subsections that follow.

- **Bifurcated Organizational and Modeling Team Structure**: ERCOT has two separate sub-groups, each with its own production cost model and its own set of inputs covering different timeframes. This creates duplication of work and risks inconsistencies in the modeling efforts. Having separate modeling teams also hinders the exchange of ideas and best practices between teams working on similar issues. Moreover, the lack of a single, coherent multi-year modeling platform limits options for considering the economic value of long-lived assets in an evolving future, as discussed in Section VI. We understand that ERCOT has already begun to address this concern by re-organizing the teams' structure to make the structure more efficient and consistent.
- **Designing Study Cases**: ERCOT could improve its modeling by defining selected scenarios in a way that is more credible to stakeholders. Other potential improvements include more fully representing generation outages (and other system stresses in the context of additional benefit metrics) that regularly increase congestion. Study cases

should also be defined carefully to distinguish between alternative and complementary transmission projects when evaluating portfolios of projects.

- **Validation of Results**: ERCOT performed some model validation in the past when the modeling tools were initially developed. Such model validation and calibration efforts should be undertaken on a more regular basis to ensure that the market simulations can reasonably represent actual market conditions, market prices, and congestion patterns. It would also be helpful to add process steps to ensure that the reasonableness of simulation results is evaluated from a higher-level perspective.

1. Bifurcated Organizational and Modeling Structure

The historic evolution of a mid-term RTP process that is separate from the long-term planning process resulted in separate modeling teams using two different production cost models. ERCOT has already begun to better integrate its modeling team structure, so our concerns reflecting the structure (as we found it when we did our assessment during early 2013) may be at least partially resolved.

We found that two different parts of the RA group provide supply and demand inputs to two separate economic models and modeling groups: one part of the RA group provides the MT Modeling group with all non-transmission data for populating UPLAN for study years 0 to 6; and another part of the RA group provides the LT Modeling group all non-transmission data for populating PROMOD IV for later study years (years 10 to 20). Maintaining two economic models requires extra work populating the models and validating results. Having different groups simulate different timeframes also risks inconsistencies that may make the planning effort less effective. For example, the last year of the MT Modeling case and first year of the LT Modeling case (used only for siting new generation) typically simulate the same year. However, model inputs (generation additions, contingency files, *etc.*) are different due to their different sources. Creating the contingency file is one of the most time consuming efforts for the LT Modeling group. The LT Modeling group does borrow the list of multiple-element contingencies from the MT Modeling group (while generating single contingencies independently), but substantial work is required to implement them in PROMOD IV.

The RA, MT Modeling and LT Modeling sub-teams were isolated without free flow of information among them. Until recently, these three groups were all separate teams. Even with the MT and LT Modeling groups now merged, the RA group is still physically separate on a different floor. Most team members are not fully aware of what the other groups do—how they develop inputs, run their models, and validate the results. There is little information flow between the MT and the LT Modeling groups, except the transfer of a 5-year load flow case and some discussion of reliability and economic solutions to consider (nor is there coordinated communication with the transmission owners). There is little flow within the RA group among those who populate the UPLAN model and those who populate the PROMOD IV model. As a result, there is sub-optimal sharing of complementary ideas and expertise. This can create inefficient workflow relative to what we experienced with more integrated teams.

In addition, individuals in the RA group may have many years of experience running PROMOD IV but may not be part of the PROMOD IV modeling effort. Because the RA group is located on a separate floor, this creates a barrier to casual interactions that could enable the PROMOD IV modelers to take full advantage of the expertise and knowledge these individuals could provide. Furthermore, we learned that individuals tend to focus on a narrow area of the modeling effort and, while they can validate accuracy in that area, nobody is evaluating the reasonableness of results from a higher-level perspective. Because each sub-team lacks knowledge about the other teams' approaches, it is difficult to develop a higher-level perspective of the reasonableness and efficiency of the overall effort.

Bifurcation of the teams and models also makes it almost impossible to consider some important aspects of long-lived assets in an evolving future, such as: advancing reliability or economic projects that have been identified in the long-term study; evaluating the present value of estimated project costs and benefits; and assessing the option value of project modifications that lessen the cost of meeting long-term needs that may occur in some scenarios. These points are discussed further in Section VI.

We recommend that ERCOT consider addressing these challenges by consolidating both its modeling platforms and modeling teams. First, ERCOT should consider putting the entire modeling staff in one contiguous space to encourage closer collaboration. All team members need to understand the high-level objectives and methodologies for addressing both reliability and economics across the different time frames. Specialization may be necessary, but it should be organized around models or disciplines, not timeframes. There could be two load flow modelers, several people who develop the various inputs (including the resource expansion plan), run PROMOD IV or UPLAN, and interpret results over all timeframes studied. One or two other staff members might run KERMIT, to evaluate ancillary service needs. Second, we recommend that ERCOT select a single economic model—for example, either PROMOD IV or UPLAN. We understand that ERCOT plans to select a preferred model later this year.

2. Designing Study Cases

Although many aspects of the study cases are well-designed, other aspects could be improved. Improvements are possible particularly in the areas of scenario development, representation of stress conditions that regularly exacerbate congestion costs, simulating portfolios of projects versus individual projects, and technical modeling matters. Our recommendations regarding improving scenario development are discussed further in Section VI.E.

Representation of Stress Conditions. Models such as PROMOD IV and UPLAN will understate the value of transmission if they are used to simulate only ideal system conditions that do not represent a realistic level of transmission congestion. The current simulations are based on weather-normalized peak loads and monthly energy without transmission outages and, at least for long-term simulations, without forced generation outages. This will tend to understate congestion costs and the value of transmission upgrades by neither subjecting the system to a realistic amount of stress nor fully accounting for the marginal cost of energy during stress periods.

As explained further in Section VI, some types of stress conditions should be included only in special scenarios or sensitivity cases, due to their irregularity and due to modeling complexities. Such conditions include a full range of weather conditions (such as the 2011 heat wave or the drought conditions ERCOT has already included as a future scenario), transmission outages (which are not traditionally included in production cost simulations but should be considered to estimate the full value of transmission investments), and congestion arising from differences between day-ahead forecasts and realized loads and renewable generation output.

We also understand that forced outages of generating plants are not considered in ERCOT's long-term simulations. We recommend, however, that forced generation outages should be added to all cases to better approximate actual congestion levels. Modeling random forced outages (and holding them constant across simulation cases) is standard industry practice, although some simulations approximate them as unit de-rates. The random approach is better because it includes a more realistic level of variability. However, adjustments are sometimes needed if a particular forced outage schedule has undue influence on the results.

In addition to modeling stress conditions due to weather and outages, it is important to model system costs accurately under scarcity conditions. Results from the reviewed simulations appear to understate costs—even during drought conditions, which is the only simulated stress condition we observed.[18] For none of the modeling cases, simulated LMPs reach scarcity pricing levels reflective of actual marginal system costs or suppliers' bidding behavior under certain system conditions. During periods of (perhaps localized) scarcity, the magnitude of congestion costs would be more realistic if the model were adjusted to include a scarcity pricing function. This is particularly important for ERCOT as it is operating under an energy-only market. We recognize that ERCOT's scarcity pricing rules are still evolving, as the Commission considers various "Operating Reserve Demand Curve" proposals. However, even before the Commission defines the final rules, scarcity pricing can be implemented in PROMOD IV to reflect more realistic market conditions. The most straightforward way is to hold aside a realistic amount of operating reserves (including regulation reserves) and then apply an inclining penalty price on depleting those reserves. An alternative is to maintain reserves and dispatch dummy units at various

[18] Note, however, that the drought case simulations assume recurring years of similar conditions such that the long-term generation mix and expansion/retirement can be optimized for these conditions. This will tend to significantly understate the impact of stress conditions on a system that was not specifically optimized for an assumption that such conditions would be encountered every year.

scarcity price levels. In this context, it is also important that the model realistically reflects which units provide operating reserves.

Model Setup. We also offer the following recommendations regarding model setup:

- *Portfolios of Transmission Projects to Simulate*. The current approach of evaluating each candidate project individually is time-intensive and yet does not directly inform whether multiple projects would be more economic in combination. In many cases, it will be perfectly appropriate to simulate individual projects. However, in some cases, combining projects with complementary purposes can reduce the time needed for the analyses and better represent the benefits of the portfolio when simulated jointly. If it is necessary to clarify the incremental value of each project in a group of complementary projects, adding projects sequentially during the analysis would be a possible approach.

- *Comparison of Appropriate Change Case to Base Case*. The evaluation of a candidate economic project's production cost benefits involves the comparison of a "Change Case" with the proposed line to a "Base Case" without the line. Currently, we understand that both the Base Case and Change Case may currently include the same group of reliability upgrades that were developed as a part of the Base Case. However, if the economic project's benefits include deferral or avoidance of certain reliability projects, those reliability projects should be removed from the Change Case that includes the proposed economic project.

- *Voltage Analysis of Interfaces*. The "AC Reliability Study/Establish Transfer Limits" part of the long-term planning process involves adding reliability upgrades to the interface definition, then increasing the interface limit based on an AC reliability analysis. Many other analysts skip that step, instead leaving the new line out of the interface definition and holding the interface limit constant. It is not clear whether the more complicated approach changes the results very much. ERCOT could test whether it does. If the simplified approach does not significantly change results, ERCOT could consider skipping that step in an effort to streamline the analysis. We also note that the AC analysis is performed only for peak summer conditions.

- *System Simplification*. The long-term Base Case development starts with a simplification of the transmission system, including removal of low-voltage buses. This step could more easily be accomplished by simply "commenting out" (or raising the limit) of the relevant constraints without actually modifying the load flow cases.

- *Network Model Handoff*. The load flow case provided to the MT group frequently has open lines, busses missing, and other problems that must be resolved before running UPLAN or PROMOD IV. Our understanding is that the Network Modeling group would be better equipped to resolve these problems, such that the LT group would receive the load flow case that has already been tested and validated by the Network Modeling and MT groups.

3. Validation of Simulation Results

Electricity market simulation models are complicated representations of an even more complicated electricity market. Thus, even if all model inputs appear reasonable, the results cannot be relied upon unless they are validated against actual market conditions. We have not evaluated whether the long-term simulation results are reasonable but, instead, evaluated the adequacy of current validation measures.

Model validation should include comparisons to actual market conditions (such as market prices, generation dispatch, and congestion levels), comparisons across cases, and high-level assessments to ensure that the results are reasonable. We understand that ERCOT is already performing some of these validation efforts but recommend additional measures.

Comparison to actual market conditions. We learned from the RA group that it had conducted some comparisons to actual market conditions when the model was first developed. We do not know how extensive these efforts were, but, in any case, validation should be undertaken more frequently as market conditions evolve. One of the most effective validation exercises is to develop a "back-cast" (or at least a near-term forecast) and compare simulation results to actual recent market conditions, focusing on price duration curves at major hubs, locational price differentials, capacity factors of dispatched generation resources, total congestion charges, and congestion duration curves on major constraints.

Comparison across cases. New cases should be compared to already-accepted simulation cases to ensure that the model is accurately incorporating the intended input changes. This requires preparing simple diagnostic reports for each run and analyzing differences to prior runs. The LT group's PROMOD IV simulation reports we reviewed contain much of the basic information one would need, and they were similar to the PROMOD IV reports that Ventyx, the model developer, uses. Many PROMOD IV modelers have become comfortable with such reports and believe they are adequate. In our experience, however, these reports do not make it sufficiently easy to identify anomalies in simulation results. We thus recommend the use of diagnostic reports that show annual unit-level performance data on one sheet and transmission constraints data on another sheet, with each sheet also comparing the generation unit transmission constraint data to a prior case (such as the Base Case or the prior run in a series of development runs). These comparison sheets can be sorted to easily identify the most significant changes, which often point to simulation or input errors of the draft model runs. We provided samples of such diagnostic reports that we produce automatically every time we perform a simulation, using customized queries and macros. ERCOT could use similar queries and macros to automate the compilation of similar diagnostic reports.

High-level review of simulation results. One team member noted that the simulation results are not being reviewed from a high-level perspective to make sure results made sense overall. Instead, it appears that specialized engineers each focus on only their portion of the overall analytical process. It would be helpful to add process steps involving review by analysts with a higher-level perspective, such as the reasonableness of case definitions and simulated market conditions. This may already be happening, but not all team members are aware of it.

V. REVIEW OF ERCOT'S TRANSMISSION BENEFIT METRICS

Developing a robust business case for economic transmission projects requires the economic value of transmission investment to be fully captured in terms of the benefits it can provide to the system. This makes it necessary to account for all costs and benefits over the useful life of the projects, properly considering uncertainties and discounting estimated costs and benefits over time. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, conservative estimates of transmission benefits or a failure to consider the full range of economic benefits of transmission investments is equivalent to understating the potentially very costly outcomes that market participants would be exposed to in the absence of these investments. It is consequently preferable to: (1) accurately estimate the full expected value of the benefits that transmission facilities can provide; while also (2) explicitly analyzing the uncertainty around these expected values to better understand the risks of incurred or avoided high-cost outcomes. This section of our report assesses the scope of economic benefits considered by ERCOT in comparison to evolving industry practices.

A. ERCOT BENEFIT METRICS VERSUS INDUSTRY PRACTICES

ERCOT currently considers two types of economic benefits in its planning efforts for economic transmission projects: (1) production cost savings, and (2) benefits related to deferred or avoided reliability upgrades. These two metrics do not capture the full societal benefits of transmission infrastructure investment. While estimating and using these two benefit metrics represents a good starting point, they reflect a narrow subset of the wider range of benefits that are increasingly considered in the industry today, including by other system operators in Texas and surrounding regions. In order to help ERCOT benefit from the quickly evolving industry experience, we summarize the types of transmission-related economic benefits quantified and considered by other system operators in other parts of the U.S.[19]

Over the past decade, several RTOs have significantly expanded the scope of the transmission benefits considered in their planning efforts to include a range of economic and public-policy benefits. Initial steps were taken by CAISO in 2004 to support the planning of multi-utility, multi-purpose, and renewable integration projects. RTOs in regions with significant renewable generation potential, such as SPP and MISO, have similarly expanded the scope of the transmission benefits considered in their planning processes—particularly in efforts to better coordinate transmission planning for the integration of renewable resources.

In Texas and its neighboring states, SPP's Integrated Transmission Planning process (ITP) has similarly moved towards examining a broader range of transmission-related benefits in its "Priority Projects" evaluations, such as production cost savings, reduced transmission losses,

[19] This discussion is in part based on the work undertaken during January through July 2013 for the WIRES group. See Chang, *et al*., 2013.

reduced emissions, and reliability benefits. The full list of benefit metrics considered is shown in Table 5 below. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group also agreed that a number of transmission benefits that require further analysis include:

- Enabling future markets;
- Storm hardening;
- Improving operating practices/maintenance schedules;
- Lowering reliability margins;
- Improving dynamic performance and grid stability during extreme events; and
- Societal economic benefits.[20]

In order to support cost allocation efforts, SPP's Metrics Task Force (MTF) has further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or reduced loss of load probability, the increased wheeling through and out of revenues (which can offset a portion of transmission costs to be recovered from SPP's internal loads), and the value of facilitating public-policy goals.[21] MTF also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

Similarly, MISO—soon to be the system operator for the Entergy region, including Entergy's service area in the southeastern portion of Texas—estimates the value of a broad set of transmission benefits in the scope of its transmission planning efforts. In its recently established Multi-Value Project (MVP) transmission planning process and associated cost-allocation methodology, MISO estimates a wide range of benefits for portfolios of projects that meet the MVP criteria.[22] In addition, MISO also stressed that the MVP portfolio provides a number of difficult-to-estimate benefits, such as enhanced generation flexibility, increased system robustness, and decreased natural gas price risk.[23] MISO is also in the process of further expanding the scope of its economic valuation process. For example, in the currently-ongoing Manitoba Hydro Wind Synergy Study,[24] MISO has estimated benefits related to production cost savings, load cost savings, ancillary service cost savings, wind generation changes, and thermal plant cycling reduction. In addition, MISO noted (but did not estimate) capacity benefits, potential operating reserve benefits (new reserve resources), and storage and energy benefits of

[20] *Id.*, p. 37.

[21] SPP, 2012.

[22] MISO, 2011, pp. 25-44.

[23] *Id.*, pp. 53-63.

[24] MISO, 2013.

the most flexible new hydro generation. These benefits are evaluated further through sensitivity analyses and risk assessment.

While perhaps less directly comparable to ERCOT, California modified its transmission review process to consider a broad range of transmission-related benefits, recognizing that additional transmission would have significantly mitigated the costs incurred during the California power crisis. Accordingly, the CAISO created its transmission economic assessment methodology (TEAM) to "establish a standard methodology for assessing the economic benefit of major transmission upgrades that can be used by California regulatory and operating agencies and market participants."[25] The TEAM process, at that time, significantly expanded the scope of CAISO transmission planning to include benefits from the increased competition, risk mitigation capability of transmission infrastructure, and the ability to import lower-cost energy and capacity from other regions.[26]

The TEAM approach specifically recognized that:

> [A] significant portion of the economic value of a transmission upgrade is realized when unexpected or unusual situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The 'expected value' of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual but plausible situations. A transmission investment can be viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.[27]

While the full scope of benefits analysis made possible by the TEAM approach is not applied in the evaluation of all economic transmission projects,[28] the California Public Utilities Commission (CPUC) adopted the broad scope of transmission benefits that can be considered through the TEAM approach. Specifically applying the approach, the CPUC approved the Palo Verde-Devers No. 2 (PVD2) transmission project, recognizing transmission benefits including:

- Production cost savings and reduced energy prices from both a societal (*i.e.*, economy-wide) and customer perspective;
- Mitigation of market power;
- Insurance value for high-impact, low-probability events;

[25] CAISO TEAM Report, 2004.

[26] CAISO PVD2 Report, 2005.

[27] CAISO TEAM Report, 2004, p. ES-10.

[28] For example, in the CAISO's most recent transmission planning process the evaluated economic benefits were limited to production cost savings, reduced generating capacity needs, and changes to transmission losses. See CAISO. 2013. Chapter 5 and pp. 301-3.

- Capacity benefits due to reduced generation investment costs;
- Operational benefits (such as reduced reliability-must-run costs and providing the system operator with more options for responding to transmission and generation outages);
- Reduced transmission losses;
- Facilitation of the retirement of aging power plants;
- Encouraging fuel diversity;
- Improved reserve sharing; and
- Increased voltage support.

In the CPUC's decision for the PVD2 project, the regulator drew additional attention to some of the benefits for which specific values were not measured. The CPUC noted: "discussion of these potential additional benefits…is useful in extending our attention beyond the limits of the quantitative analysis. We consider these factors in our consideration of [the project's] economic value, even though their potential benefits have not been measured."[29] The importance of these and other transmission-related benefits of transmission investments have also been discussed in a report sponsored by the California Energy Commission.[30]

Other states have also recognized that transmission projects can provide a broad range of benefits. For example, the Wisconsin Public Service Commission approved in June 2008 its first "economic" transmission line, the Paddock-Rockdale project. That project was approved based on both estimated and qualitatively-discussed economic benefits (for seven alternative future scenarios) that included: (1) adjusted production cost savings; (2) energy and capacity cost savings from reduced transmission losses; (3) reduced power purchase costs due to increased competition; (4) reliability and system failure insurance benefits; (5) long-term resource cost advantages; (6) lower reserve margin requirements; and (7) benefits from the increased availability of financial transmission rights (FTRs).[31]

In contrast to these developments, however, the three northeastern system operators (i.e., NYISO, ISO-NE, and PJM),[32] like ERCOT, still continue to plan their transmission system primarily for reliability needs and they are using only traditionally-estimated production cost savings to screen for new "economic" or "market efficiency" transmission projects.

The range of economic benefits considered by other Texas and U.S. system operators is summarized in Table 5. Additional transmission-related benefits may be considered within

[29] CPUC *Opinion*, 2007, p. 50.

[30] Budhraja *et al.*, 2008.

[31] ATC (2007).

[32] New York Independent System Operator, Independent System Operator of New England, and PJM Interconnection.

individual utilities' integrated resource planning (IRP) processes and will depend on state regulatory requirements.

Table 5
Benefits Considered in Planning Processes of Other Regional System Operators

System Operator Planning Process	Benefits Estimated	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	• Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits	• Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	• Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction	• Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP's Metrics Task Force	• Reduced energy losses • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or reduced loss of load probability • Increased wheeling through and out revenues • Value of facilitating public policy goals	• Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity
MISO MVP Analysis	• Production cost savings • Reduced operating reserve needs • Reduced planning reserve needs • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs	• Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO_2 emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	• Reliability benefits • Production cost savings	• Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	• Reliability benefits • Production cost savings	• Public policy benefits
ISO-NE RSP	• Reliability benefits • Net reduction in total production costs	• Public policy benefits

B. A "Checklist" of Potential Societal Benefits of Transmission Investments for ERCOT

Based on the industry experience summarized above and our own experience of working with transmission developers and system operators, we assembled a comprehensive catalogue of potential economic benefits that transmission investments can provide. This "checklist of economic benefits" is summarized in Table 6 and presented in more detail in Appendix B. It shows the production cost savings traditionally estimated as well as additional categories of benefits that often are not evaluated or even considered. Appendix B also provides a more technical discussion of the metrics and experience (including a more detailed discussion of "other project-specific benefits") with analytical techniques from other regions that can also be applied to estimate the value of these benefits.

Although many of these benefits have not been traditionally considered or estimated by ERCOT and other system operators, this range of benefits represents the starting point for improving ERCOT's economic planning process in an effort to more fully estimate the economic benefits of transmission investments. As noted earlier, because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to understating the potentially very costly outcomes that market participants would be exposed to in the absence of the investments.

We provided ERCOT with this "checklist" and a draft of Appendix B to discuss which of these additional economic benefit metrics are most applicable to the ERCOT region and to identify which of these metrics ERCOT could develop and incorporate in its transmission planning efforts over time. As noted during our June 3, 2013 presentation to ERCOT stakeholders, this checklist of potential benefits does not necessarily mean that every category of benefit would increase the value of all transmission projects. Rather, some of these benefit categories may yield negative values for certain projects, thus representing a net increase in societal costs.

Table 6
Summary Table of Potential Economic Benefits

Benefit Category	Transmission Benefit
Traditional Production Cost Savings	Production cost savings as currently estimated, including impact of planned and forced generation outages
1. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. Reduced planning reserve margin
3. Generation Investment Cost Savings	a. Generation investment cost benefits from reduced peak energy losses
	b. Deferred generation investments
	c. Access to lower-cost new generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of facilitating public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

C. RECOMMENDATIONS CONCERNING BENEFIT METRICS

We reviewed the above checklist of potential metrics with ERCOT staff, assessed their applicability and relative importance within ERCOT, and identified the most readily implementable metrics that could be added by ERCOT in the near-term to improve its current economic modeling practices. We also identified promising benefit metrics that will require the development of additional modeling tools and analytical capabilities before implementation is possible. In parallel, ERCOT has begun to develop case studies that apply some of the identified approaches and metrics to gain familiarity with the modeling and analytical efforts necessary to build the "tool kits" that can be used to evaluate proposed economic transmission projects in the future. Our recommendations are summarized in Table 7 and are discussed in more detail further below. These recommendations reflect a societal perspective of transmission-related benefits and costs—as opposed to solely relying on a customer perspective that may omit benefits or costs imposed on other market participants—as required by the PUCT.[33]

Based on our review of ERCOT's modeling practices and capabilities, we have differentiated our recommendations in terms of near-term and longer-term implementation of improvements to the existing benefit metrics and the implementation of additional benefit metrics. As Table 7 summarized, some additional metrics can be integrated into the transmission planning process such that they are evaluated routinely for each project or group of projects. Others would require periodic studies to develop and update typical multipliers that could then be applied to the evaluation of individual projects. As Table 7 also shows, we recommend a set of benefit metrics that would be developed on a case-by-case basis as projects with likely yield types of benefits are evaluated in the future. We also recommend that ERCOT qualitatively consider the remaining benefit metrics. As transmission projects with likely significant amounts of those specific benefits are evaluated in the future, it may be warranted to develop quantitative tools to estimate the monetary value of these benefits.

[33] The Public Utility Commission of Texas (PUCT) requires that transmission projects be evaluated from a societal perspective, explicitly rejecting the use of a consumer impact or generator revenue reduction perspective for the evaluation of economic transmission projects in ERCOT. See PUCT Order, 2012.

The PUCT Order refers to societal benefits as "levelized annual savings in system production costs resulting from the project," consistent with the current scope of ERCOT's economic benefit metrics (*id.*, pp. 15 and 18). However, the PUCT also concluded that "indirect benefits and cost" (*id.*, p. 32) associated with a project—as also contemplated in ERCOT Nodal Protocols, Section 3.11.2(5)—should be considered as well. A discussion of the difference between applying a societal and consumer perspective is included as Appendix C.

Table 7
Recommended Additional Benefit Metrics for Near- and Longer-Term Implementation

Checklist of Potential Economic Benefits of Transmission		Already Used	Recommended for Near-Term Implementation	Recommended for Longer-Term
1. Traditional Production Cost Savings ***(as currently considered by ERCOT)***		✓	Improve	
1a – 1i. Additional Production Cost Savings				
a.	Impact of generation unit outages and designations for ancillary services		✓	
b.	Reduced transmission energy losses		✓	
c.	Reduced congestion due to transmission outages		✓ (multiplier)	
d.	Mitigation of extreme events, system contingencies			✓
e.	Mitigation of weather and load uncertainty		✓ (multiplier)	
f.	Reduced costs due to imperfect foresight of real-time conditions			✓
g.	Reduced cost of cycling power plants		✓	
h.	Reduced amounts and costs of ancillary services			✓
i.	Mitigation of RMR conditions			✓
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects *(as already considered by ERCOT)*	✓	Improve	
b.	Reduced loss of load probability, or:			✓
c.	Reduced planning reserve margin			✓
3. Generation Investment Cost Savings				
a.	Generation investment cost benefits from reduced peak energy losses		✓	
b.	Deferred generation capacity investments		Case by case	✓
c.	Access to lower-cost generation		Case by case	✓
4. Market Benefits				
a.	Increased competition			
b.	Increased market liquidity			
5. Environmental Benefits				
a.	Reduced emissions of air pollutants		✓	
b.	Improved utilization of transmission corridors		Qualitative	✓
6. Public Policy Benefits				
a.	Reduced cost of facilitating public policy goals			
7. Employment and Economic Stimulus Benefits				
a.	Increased employment and economic activity; increased tax revenue			
8. Other Project-Specific Benefits				
such as:	Storm hardening, load serving capability, synergies with future transmission projects, fuel diversity and resource planning flexibility, wheeling revenues, transmission rights and customer congestion-hedging value, HVDC operational benefits		Case-by-case	Synergies with future T; fuel and planning flexibility

1. Recommendations for Near-Term Implementation

We offer the following recommendation for the near-term implementation of improved and additional benefit metrics for further consideration by ERCOT. Appendix B provides additional guidance for each of the discussed benefit metrics.

- *Improve traditional production cost savings metric (#1).* As discussed in more detail in the next section of this report, we recommend that ERCOT expand the time horizon of estimating production cost savings beyond an economic project's first year of operations.

- *Impact of generation unit outages and designations for ancillary services (#1a).* We recommend that ERCOT add the simulation of forced generating unit outages to its long-term planning simulations.[34] To ensure consistency across Base and Change cases, the draw of forced unit outage should be held constant. ERCOT should also analyze and reflect in its market simulations the extent to which generating units are dedicated to provide ancillary services (and are thus not available for congestion management).

- *Reduced transmission energy losses (#1b).* We recommend that ERCOT estimate the extent to which transmission investments reduce the quantity and cost of supplying transmission losses by either: (i) simulating changes in transmission losses in PROMOD or UPLAN; (ii) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (iii) utilizing marginal loss charges (from production cost simulations with constant loss approximation).[35] Due to the potentially significant additional effort, this benefit may be evaluated for a portfolio of promising economic projects rather than for each simulation of each project.

- *Reduced congestion during transmission outages (#1c).* We recommend that ERCOT study the extent to which transmission outages increase congestion and production costs relative to standard market simulations assuming all transmission facilities are available 100% of the time. By analyzing for several economic transmission projects how much consideration of transmission outages would typically increase the production cost savings compared to standard market simulations that do not reflect transmission outages, ERCOT should be able to develop a "multiplier" that can be applied to the results of the standard market simulations.[36] The multiplier can be updated over time as more

[34] We understand that maintenance outages are already modeled.

[35] For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see SPP, 2012, Section 4.2. See also Pfeifenberger Direct Testimony, 2008. Note that if transmission additions facilitate additional generation from remote generation, total transmission losses may increase, thus representing an increase in loss-related costs.

[36] For example, a recent SPP study showed that modeling a subset of transmission outages over a 12-month period increased the production cost savings of a broad portfolio of transmission projects by about 11.3%. See SPP, 2013, Section 7.5.4. See also discussion in Appendix B.

experience is gained with the analysis of how the consideration of transmission outages affects project benefits.

- *Mitigation of weather and load uncertainty (#1e).* We recommend that ERCOT study the extent to which the combination of 10/90, 50/50 and 90/10 ranges of weather and load conditions affects the probability-weighted "expected" production costs savings of new transmission projects compared to the standard market simulations that are based only on normalized peak demand and monthly energy consumption (*i.e.*, 50/50 weather and load conditions).[37] For example, as noted by Luminant, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the Base Case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[38] Note, however, that the ratio was calculated for consumer benefits; it may differ for production cost savings. By analyzing this ratio for several transmission projects or a portfolio of projects, ERCOT should be able to develop a "multiplier" that can be applied to the results of the standard market simulations (reflecting only normal weather and load conditions).

- *Reduced costs of cycling power plants (#1g).* We recommend that ERCOT report in its simulations the cycling frequency of generating plants with high startup and shutdown costs. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about $200/MW per start (with a range between $160/MW and $260/MW). The costs associated with equipment damage account for more than 80% of this total.[39] We recommend that ERCOT estimate through post-processing of its simulation results the extent to which transmission investments may decrease (or increase) such cycling costs beyond the fuel and variable O&M costs already considered in the simulations.

- *Improve the current estimates of avoided or deferred reliability project costs (#2a).* As discussed in more detail in the next section of this report, we recommend that ERCOT improve its process to estimate the extent to which an economic transmission project can

37 See SPP, 2012, Section 9.6.

38 ERCOT, 2011a, p. 10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

39 See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from $2008 to $2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

avoid or defer future reliability projects by estimating this benefit beyond the first year of the economic project's operations. This may show that a reliability project avoided in the first year of an economic project's operations may still be needed in the future (*i.e.*, would only be deferred) while there may be additional reliability projects that are either avoided or deferred after the economic project's first year of operation.

- *Generation investment cost benefits from reduced peak energy losses (#3a).* We recommend that ERCOT calculate the extent to which economic projects (or portfolios of economic projects) reduce resource adequacy requirements by reducing transmission losses during annual system peaks. For example, at a target planning reserve margin of 15%, a 100 MW reduction in on-peak losses (*e.g.*, as estimated through power flow simulations) would reduce installed generation needs by 115 MW. The societal value of this benefit can be determined by multiplying the reduced generation need by the annualized net cost of new generation (net of simulated annual energy and ancillary service margins).

- *Deferred generation investments and access to lower-cost generation (#3b, #3c).* We recommend that ERCOT evaluate the potential benefits of economic transmission projects on a case-by-case basis. For example, a transmission project may allow moving a needed generating plant from a high-cost location (*e.g.*, in a metropolitan area) to a location with significantly lower costs (*e.g.*, a less densely populated area with a lower-cost site, lower environmental compliance costs, lower infrastructure costs, and lower fuel and O&M costs).

- *Reduced emissions of air pollutants (#5a).* We recommend that ERCOT confirm that emission costs are reflected for pollutants with a market price for emissions. We also recommend that the reduced emissions without market prices (such as particulates and mercury) be quantified and its societal value be considered at least qualitatively. For long-term scenario-based planning and to assess the risk-mitigation aspect of transmission investments, we also recommend that ERCOT consider simulating futures with higher emission costs, including the possibility of climate legislation with carbon pricing.

- *Improved utilization of transmission corridors (#5b).* We recommend that, in the near-term, ERCOT consider at least qualitatively the extent to which alternative transmission options (both alternative reliability projects and economic projects) may be more effective in utilizing existing rights-of-way or minimizing the long-term need for additional rights-of-way. For example, upsizing a new transmission line today can avoid the need for a second line in the future, thus reducing the total long-term need for right-of-way.

- *Other project-specific benefits (#8).* We recommend that ERCOT consider and develop benefit metrics on a case-by-case basis to the extent to which a transmission option may provide: (a) storm hardening benefits; (b) increased local load-serving capability (thereby supporting economic development); (c) synergies with future transmission projects (*e.g.*, allowing for a low-cost option for future upgrades, such as the completion of a 345kV loop around Austin); (d) increased fuel diversity and resource planning flexibility (*e.g.*, by providing lower-cost outcomes in more challenging future scenarios); (e) increased wheeling revenues (*e.g.*, if transmission projects are considered that would support increased exports of renewable energy); (f) increased transmission-rights and congestion-hedging opportunities; and (g) unique system operations benefits (*e.g.*, through HVDC transmission technology).

2. Recommendations for Longer-Term Implementation

In addition to the above recommendation for near-term implementation, and for further consideration by ERCOT, we offer the following recommendations for the longer-term to improve the scope of benefit-cost analysis and capture the value of additional benefits (or costs). Appendix B also provides additional guidance for each of the discussed benefit metrics.

- *Mitigation of extreme events and system contingencies (#1d).* We recommend that ERCOT develop a data set of extreme but realistic events and system contingencies. Simulating such outcomes for future years will allow ERCOT to estimate the extent to which transmission expansion reduces the costs associated with these events and contingencies. The set of events and contingencies may be based on historical data for major storms, significant weather and drought events (such as summer 2011), or unusual but possible multiple generation outages (*e.g.*, due to regulatory actions or single-source failure of fuel supply). The data set would also require the season and duration of the events, and an estimate of the probability with which these or similar events might occur in any particular year (*e.g.*, 5%), which can then be applied to the estimated cost reductions. Though some projects may require the definition of specific events and contingencies, a common set of extreme events and contingencies will likely be useful to evaluate a wide range of economic projects (or portfolios of projects).

- *Reduced amounts of ancillary services and reduced congestion due to imperfect foresight (#1f, 1h).* We encourage ERCOT to further develop its modeling of the implications of imperfect foresight of real-time system conditions and intra-hour balancing of supply and demand through ancillary services. Although the current modeling effort (using the KERMIT software) is not focused on the role transmission can play in this context, transmission investment that creates a larger unconstrained, more diversified market can reduce ancillary services needs and the system-wide costs associated with imperfect foresight.[40]

- *Mitigation of RMR conditions (#1i).* Production cost simulations typically do not capture the extent to which transmission investment can reduce the need for out-of-market reliability-must-run commitment (e.g., due to voltage constraints or second contingency conditions). To the extent that significant costs for such out-of-market RMR commitments are incurred in the future as load grows within import constrained regions, we recommend that the extent to which transmission investment avoid RMR commitments and associated costs be analyzed and simulated. This may require manually adjusting must-run generation levels in production cost simulations with and without the contemplated upgrade.

- *Reduced loss of load probability <u>or</u> reduced planning reserve margin (#2b, 2c).* Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of load curtailments, thus improving physical reliability of the system in addition to production cost savings.[41] This provides direct societal value in the form of either reducing the MWh of lost load or by allowing ERCOT to reduce its target reserve margin. To assess the extent to which transmission investments can provide these benefits, we recommend that ERCOT further explore this benefit and develop corresponding metrics. ERCOT may be able to do so by utilizing the results of its zonal reliability analysis or by using PROMOD in reliability simulation mode.

- *Deferred generation investments and access to lower-cost generation (#3b, 3c).* We recommended that ERCOT explore this benefit in the near-term on a case-by-case basis, as discussed above. In addition to this case-by-case approach, we recommend that ERCOT further study the extent to which generation costs (investment costs, other fixed costs, or operating costs) may differ across locations and sites. Improved data on such locational cost differences will also be helpful in the scenario-based resource expansion analysis of ERCOT's future long-term planning efforts.

- *Improved utilization of transmission corridors (#5b).* Scarcity of transmission rights-of-way and environmental impacts of establishing new rights-of-way can be one of the most important determinants of the economic desirability and political feasibility of

[40] From a long-term planning perspective, any additional buildout of intermittent renewable resources may also increase ancillary service needs and system costs related to imperfect foresight. Transmission expansion may reduce ancillary service needs and system costs related to imperfect foresight all else being equal. However, since all else is not equal for long-term planning purposes, these impacts need to be taken into account in scenarios developed for long-term planning purposes.

[41] Transmission may achieve such physical reliability benefits, for example, by reducing higher loss of load probability in import-constrained load pockets or by increasing interconnections with neighboring regions.

transmission expansion. In addition to considering transmission corridor utilization on a case-by-case basis in the near term as discussed above, we thus recommend that ERCOT develop a more systematic approach to consider this factor in its long-term planning processes. As noted earlier, upsizing near-term projects or creating options to upsize lines in the future may yield significantly improved utilization of transmission corridors in the long-term.

- *Synergies with future transmission projects (#8).*[42] In addition to considering this benefit of some transmission options on a case-by-case basis in the near term, we also recommend that ERCOT develop a framework to more systematically capture this aspect of transmission planning (*e.g.*, how to modify near-term transmission projects that create low-cost options in the long-term).
- *Increased fuel diversity and resource planning flexibility (#8).*[43] We also recommend that ERCOT develop a framework to more systematically capture the fuel diversity and resource planning flexibility benefit of transmission investments. It may be possible to study different scenarios and sensitivities of generation expansion and retirement cases to better understand the value of transmission to mitigate future costs associated with currently unexpected shifts in relative fuel prices, technology costs, and unexpected retirements or resource needs.

As noted, we also recommend that ERCOT qualitatively consider the remaining benefit metrics listed in Table 7. As transmission projects with likely significant amounts of those specific benefits are evaluated in the future, it may be warranted to develop quantitative tools to estimate the monetary value of these benefits. Appendix B provides some additional guidance for those metrics.

42 See Item 8c in Appendix B, page B-5 and subsequent discussion.

43 See Item 8d in Appendix B, page B-5 and subsequent discussion.

VI. IMPROVEMENTS FOR THE OVERALL TRANSMISSION PLANNING PROCESS AND DECISION CRITERIA

Based on our review of ERCOT's long-term transmission planning process and the findings summarized above, we developed the following recommendations for further consideration by ERCOT and its stakeholders. These recommendations, summarized in Table 8, are focused on enhancing ERCOT's planning process for evaluating the economic benefits and costs of transmission investments from a societal perspective, as required by the PUCT.

Table 8

Recommendations for Enhancing ERCOT's Transmission Planning Process	
1:	Link Near- and Long-term Planning Processes
2:	Evaluate Economic Projects based on their NPV or a Comparison of Levelized Benefits and Costs
3:	Expand Benefits (and Costs) Considered and Quantified
4:	Identify Key Uncertainties and Improve Development and Use of Scenarios and Sensitivities
5:	Enhance Economic Project and Benefits/Costs Identification Process

The initial draft of these recommendations was presented to stakeholders publicly at the June 3, 2013 ERCOT Regional Planning Group meeting. The slides used to present our draft recommendations ("Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process") are provided in Appendix E. The remainder of this section first summarizes stakeholder comments on our draft recommendations, then presents our final recommendations on each of the five topics summarized in Table 8. We already discussed Recommendation No. 3 (additional benefit metrics) in Section V of this report but, for convenience, we will further summarize our recommendations below.

A. STAKEHOLDER COMMENTS ON DRAFT RECOMMENDATIONS

We received eleven sets of stakeholder comments in response to our draft recommendations presented at the June 3, 2013 stakeholder meeting. They included (listed in alphabetical order) comments from American Electric Power (AEP), Electric Power Engineers, an ERCOT staff member (not previously involved in this effort), Lower Colorado River Authority (LCRA), Lone Star Transmission, Luminant, Oncor, a PUCT staff member, Save Our Scenic Hill Country Environment (SOSCHE), South Texas Electric Cooperative, and Texas Industrial Electricity Consumers (TIEC).

The comments received covered a diverse set of opinions, ranging from broad support for the presented recommendations, to a view that new transmission projects should only be planned to maintain reliability and low costs to consumers (as opposed to considering societal benefits), to concerns about the value or process of scenario-based planning, and the position that benefits more than a few years in the future are highly speculative and should not be considered. In general, however, the majority of stakeholders support: (a) linking the long-term planning effort to the near-term RTP process for the evaluation of economic projects; (b) adding at least a subset of the potential additional benefit metrics (after considering additional stakeholder input); and (c) utilizing NPV concepts in comparing costs and benefits (although differences of opinions exist about the discount rates that should be applied to long-term benefits and costs)

To provide the full context of these comments, they are summarized for individual parties as follows:

- Largely supports recommendations, which should be implemented in near term. Single economic model should be used for near-term and long-term. Supports additional benefit metrics and improvement to how costs and benefits are compared. Additional production cost savings recommendations 1a through 1g should be implemented as soon as possible. Tentatively supports implementation of metrics 2a and 3a, 2b, or 2c, and 8b and 8c as soon as possible. Some of the others may be more controversial or could be delayed for further consideration.

- Reach consensus on and adopt the most promising and pragmatic recommendations; highly unlikely transmission improvements will lose value and benefits, but assigning dollar value to long-term benefits is difficult given substantial uncertainties of projecting benefits 40 years into the future; production cost modeling not yet sufficiently accurate; use of other benefits that may or may not be quantifiable would be a good improvement; such benefits may be avoiding cost of smaller projects in the future and reducing cost of planned transmission outages; more explanation and tool development is needed for other metrics.

- Transmission should be planned to maintain reliability and lower costs to consumers; STEC is highly skeptical of benefits that extend more than a few years into the future; benefits that do not directly benefit consumers should not be counted.

- Transmission should be built only to maintain reliability and lower costs to consumers. Benefits under speculative scenarios should be heavily discounted. Purely speculative benefits should not be included at all. Benefits should be counted only if they directly reduce customer costs. Economic stimulus value should not be counted. Net present value approaches should discount benefits more than costs. Projects should be evaluated to include option value, including option to delay investment. Beneficial projects should not be grouped with uneconomic projects.

- Supports linking long-term planning to RTP process and use of long-term planning results to evaluate economic projects in RTP. Groups of benefits not currently considered should be considered in stakeholder process through phased approach, first considering additional production cost savings, then reliability and resource adequacy benefits, followed by environmental and other benefits. Focus only on benefits most relevant/applicable to ERCOT.

- Benefits not considered in ERCOT planning process are very significant, including metrics such as cost of losses, benefit of reduced cycling of generators, deferred cost of reliability, *etc.* ERCOT should explain how long-term planning results are used for evaluating nearer-term projects.

- Agree that long-term and RTP processes should be linked so that long-term planning results can be used in evaluating economic projects in RTP; supports scenario and sensitivity assessment to demonstrate project purpose, need and overall value; will assist TSP during implementation phase. To support developing/evaluating large transmission projects, ERCOT/TSP workshops should be used more frequently than once a month.

- Generally supportive of recommendations on improvements and modeling practices. Levelized benefit-cost comparison and using long-term planning results in RTP process would provide the most immediate value. Improving use of scenarios and sensitivities will help develop more robust transmission plans. Until these recommendations are implemented, put on hold and possibly revisit new benefit metrics that will require development of additional data and tools.

- Long-term projections beyond 10 years are of limited use due to uncertainty about the future. Long-term cost-benefit analyses need to recognize and quantify that benefits are more driven by uncertainties about the future than costs.

- Accuracy of scenarios decline and discounted as planning cases move further into the future; sufficient number of scenarios should also include possible impact of technological change; high-probability and low-probability scenarios should be weighted differently.

- Make explicit that ERCOT's generation modeling does not currently include back-up and reliability costs for intermittent resources, particularly wind generation. Address metrics that could address concerns about transmission, such as percentage of existing right-of-way that can be utilized.

Our finalized recommendations are discussed in detail below.

B. Link Near-Term and Long-Term Planning Processes

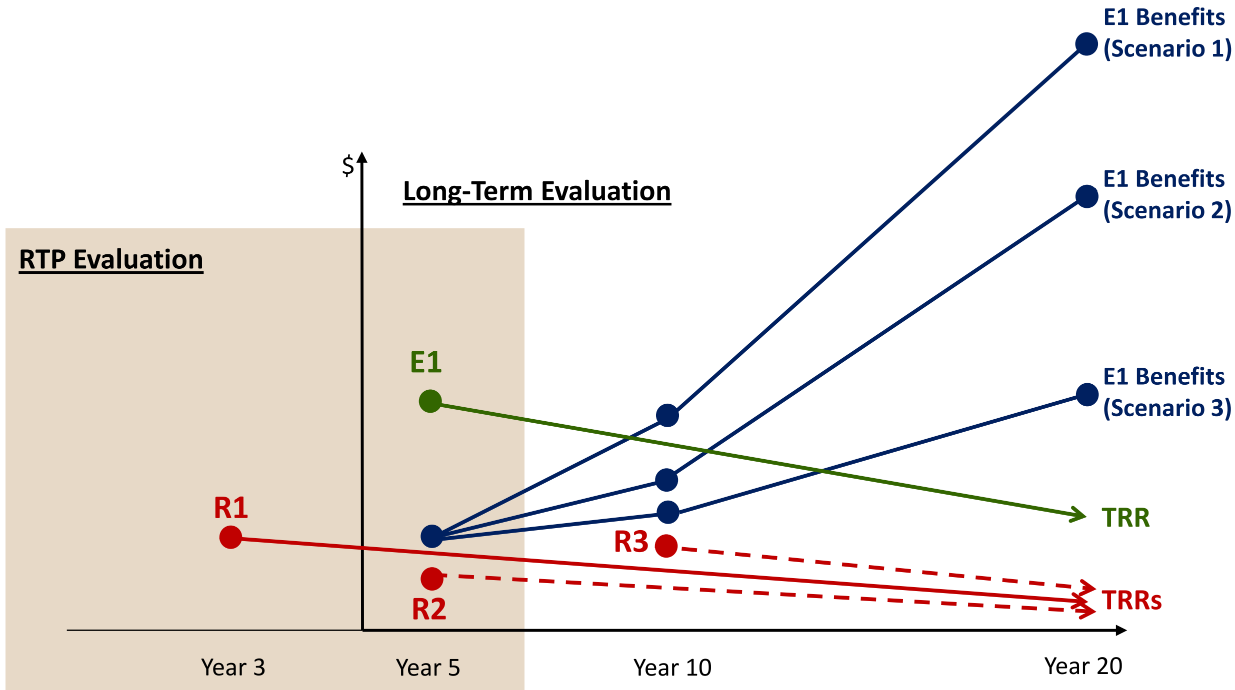
We recommend that ERCOT more systematically link its long-term (LTSA) transmission planning processes and the near-term (RTP) planning process. Such linkage would increase the consistency in modeling assumptions and results between the studies performed for two separate planning horizons. It would also avoid duplicate modeling efforts, and allow the effective use of results from long-term studies to inform near-term planning efforts. Accordingly, we also recommend that ERCOT integrate its near- and long-term modeling teams and use a single economic model with consistent set of input assumptions for both the near-term and long-term analyses. Such integration would help improve the quality, consistency, and efficiency of the workflow and enable a more integrated transmission planning process going forward.

Specifically, we recommend that ERCOT use the results of its long-term studies in the identification and evaluation of economic transmission projects within its RTP process. Transmission needs would continue to be determined and approved primarily through the RTP process, with most projects considered to be built over the ensuing 5 to 6 years of the RTP time frame. However, the monetary value of the benefits and costs of economic projects that could be developed within that 5 to 6 year time frame would be estimated based on results from both the near-term and long-term analyses. Utilizing information about the benefits and costs of an economic project over a significant portion of its useful life would help determine the actual economic value of a project, which in turn would help assess more accurately the tradeoffs between incremental reliability upgrades and economic project alternatives.

Figure 2 illustrates our recommendation of linking the near- and the long-term planning processes. This hypothetical example compares annual dollar values of benefits and costs of projects (y-axis) over the time frame of both the RTP and long-term planning processes (x-axis). The RTP process (over the first 5–6 years) is highlighted by the shaded block on the left. In this example, the RTP process identified two reliability upgrades, “R1” and “R2,” which would be needed in years 3 and 5, respectively. The red dots and lines corresponding to R1 and R2 represent the regulated annual costs of the reliability projects (in terms of annual transmission revenue requirements or “TRRs”). These annual costs decline as the assets are depreciated over their useful life (typically estimated at 40 to 50 years).

Figure 2 also shows that an economic transmission project, “E1,” proposed to be installed in year 5, could replace R2 while also providing additional economic benefits. In this example, if E1 were built, then R2 would not be needed. The green dot and line that correspond to E1 illustrate that the annual costs of E1 are significantly higher than the annual costs of R2. However, in addition to avoiding the construction of R2, the development of E1 would also offer incremental savings above those associated with R2 as indicated by the three trajectories of blue dots and lines. The three blue lines depict the project’s total annual savings under three alternative future scenarios.

Figure 2
Linking Near-Term and Long-Term Evaluation of Economic Projects



ERCOT's current evaluation process focuses on only the first year of the projects' costs and benefits. Accordingly, ERCOT calculates the E1's first-year revenue requirements net of the avoided first-year costs of R2, and then compares these net costs against the first-year annual production cost savings of Project E1. With such a comparison and threshold, as illustrated, the economic project E1 would be rejected because its first-year costs net of avoided R2 costs exceed production cost savings in that year.

The three blue lines show that the E1's annual production cost savings would grow over time, at different rates based on the alternative future scenarios considered. Such growth is typical due to the combined effects of load growth and increasing fuel prices. It is also possible that the production cost savings would decrease over time if load and fuel prices decrease or if the avoided future reliability projects offer similar levels of production cost savings as E1 does. Therefore, the three different trajectories of annual benefits depend on the assumptions used in depicting the alternative future scenarios.

According to the example shown in Figure 2, it is assumed that if E1 were built in year 5, it would also avoid another reliability upgrade, "R3," in year 10 (which would likely be identified in the subsequent RTP evaluations in absence of E1). Thus, an evaluation of whether the economic project E1 should be pursued requires estimates of such avoided reliability project costs that would be offered by E1 over time.

In Figure 2, we only show the hypothetical annual production cost savings and the avoided annual cost of reliability upgrades R2 and R3. Nevertheless, as illustrated, while the economic project E1 could not be justified by comparing first-year costs with its limited first-year benefits, the total *value* of the economic project's annual benefits over its useful life, even if discounted for future years, would likely exceed the total project costs. Another way to look at this is that if the system needs are only considered in the RTP process without regard for the longer term time horizon, the total cost to society will be greater. Hence, there is a societal impact if the long-term costs and benefits are not also analyzed when evaluating projects that can be placed into service in the near-term.

As the illustration in Figure 2 shows, the economic project E1 would still undergo evaluation and approval through the RTP process for completion in year 5, but the comparison of its benefits and costs would be informed by the results from the long-term assessment that reaches out 20 years. The scenario-based long-term assessment would also indicate the robustness of the economic project's value under the alternative future scenarios.

Linking the near-term RTP with the long-term process will allow for the costs and benefits over the lifetime of the transmission assets to be considered in the analysis of economic projects in the RTP. We also believe linking long-term evaluation results from ERCOT's long-term planning process to the evaluation of near-term projects in ERCOT's RTP process is consistent with ERCOT protocols and PUCT orders that define transmission benefits as the "estimated levelized annual savings in system production costs" plus any "indirect benefits" other than production cost savings.[44] As discussed further in the next subsection of our report, determining the "levelized annual" value of transmission benefits requires that the value of transmission benefits is "levelized" over the time period during which the benefits accrue. Considering that transmission assets will produce benefits (however uncertain) over the entire useful life of the assets, this requires the evaluation of benefits from a long-term perspective.

C. Evaluate Economic Projects Based on their Net Present Value (NPV) or a Comparison of Levelized Benefits and Costs

The economic benefits of transmission projects and their alternatives accrue over the entire life of the asset. We consequently recommend that the long-term value of costs and benefits be considered in the evaluation of potential economic transmission projects. While decisions about necessary reliability-driven transmission projects can be made based on conditions in the year when the identified reliability need first occurs, decisions about economically-justified projects require the assessment of *economic value*, which at any point in time is defined by the benefits and costs that accrue over the remaining useful life of the investment.

[44] See PUCT Order, 2012, pp. 15, 18 and 32.

We first discuss this aspect of our recommendations in more detail and then present a case study to illustrate the application of evaluating economic projects through NPV or levelized benefit-cost analyses.

1. Concept of and Recommendations for NVP or Levelized Benefit-Cost Analyses

The current ERCOT practice of evaluating economic projects is typically to perform production simulations for just the first year of the proposed project.[45] ERCOT then compares the first-year production cost savings against 1/6th of the project's construction costs, net of 1/6th of any avoided reliability project costs in that year. Taking 1/6th of a project's construction cost is approximately equal to the project's regulated cost of service (*i.e.*, its regulated transmission revenue requirement or TRR) in the first year. This approach carries a high risk of rejecting potentially beneficial economic projects for three main reasons:

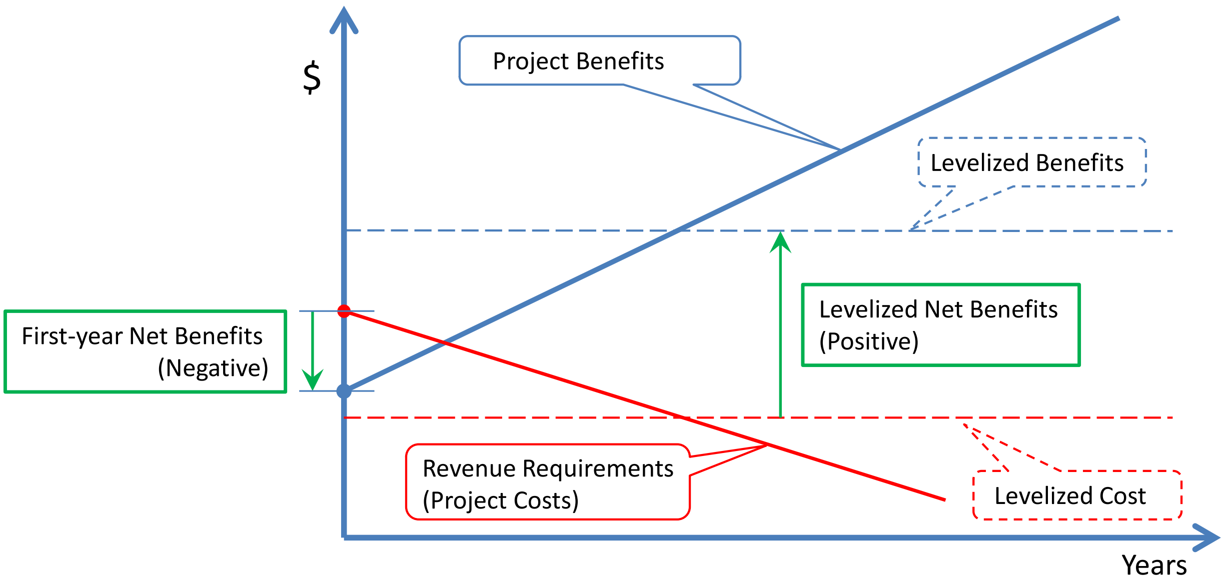
a. Production cost savings and other benefits tend to grow over time with increasing load and fuel prices (although this may not be always the case). As a result, the production cost savings for the first year of a project are generally lower than the "levelized" annual benefit that reflects the project's average savings over time. Figure 3 below illustrates how the levelized annual value of long-term benefits can be much larger than the benefits in the first year of a new project. As illustrated, it can easily be the case that first-year benefits are less than first-year costs even though levelized benefits significantly exceed both first-year costs and levelized costs.

b. The annual cost of transmission investments, reflected in TRRs, decline over time as the assets are depreciated. The first-year TRR of a project, estimated as 1/6th of its construction cost, is approximately 30% higher than the levelized annual value of its TRR over time. Thus, if benefits need to exceed 1/6th of the project's construction cost, then the levelized benefits have to be approximately 30% greater than the project's levelized revenue requirements.

c. The economic projects may offer benefits beyond production cost savings as discussed before. This likely includes benefits to materialize after the first-year, such as the benefits associated with avoided reliability project costs, which should be considered in the benefit-cost analyses as well.

[45] ERCOT simulates all years that they have models available for in which the proposed project will be placed in service, although this is generally just for the first year of operation. For example, if a project is projected to be in-service in 2015 and models are available for both 2015 and 2017, then both years will be modeled. However, if the project is proposed to be on-line in 2017, only one year will be modeled, which is generally the case.

Figure 3
Comparing First-Year and Levelized Project Costs and Benefits



For these reasons, we recommend that the costs and benefits associated with proposed transmission projects be compared based on their present values or levelized values. The present value approach compares the present value of a project's long-term benefits to the present value of a project's costs. The present values of benefits and costs are estimated as the sum of annual benefits and annual costs, both increasingly discounted over time to reflect the fact that a dollar spent or saved 10 or 20 years from now is significantly less valuable than a dollar saved or spent today.

As an alternative to comparing the present values of benefits and costs, it is equally suitable to compare the benefits and costs using levelized annual values. This is because the levelized costs and benefits would yield the same present values as the estimated time-varying amounts; therefore, they would lead to the same benefit-to-cost ratios. The NPV-based or levelized benefit and cost comparisons are used by virtually all other system operators and we recommend ERCOT adopt a similar methodology.

To estimate annual benefits over time, the annual values can be interpolated based on specific estimates for a few future study years, such as year 1, year 5, and year 10 (or year 20) and then extrapolated further into the future based on a conservative assumption of how benefits would remain over time. It is important to recognize that the value of transmission investments rarely declines over the long term. The time frame over which the annual benefits and costs are estimated for present value calculations is typically between 20 and 40 years in most of the other planning regions, although some system operators use time horizons as low as 10 years while others estimate values over the full 50 years of a project's assumed life.[46] We recommend that ERCOT consider estimating benefits and costs over a time horizon between 20 and 40 years, consistent with the other system operators in Texas and neighboring regions.

We recommend ERCOT use a PUCT-approved weighted average cost of capital (WACC) of the transmission owners to discount estimated future benefits and costs, although some planning regions (such as the MISO) also use a lower "societal" discount rate. Using a PUCT-approved WACC as a discount rate would appropriately reflect the risks of transmission investments. Using higher or lower rates, or applying different rates to benefits and costs would not properly capture the projects' risks and it would also misrepresent the potential costs imposed on market participants in the absence of the contemplated transmission investment.

Economic projects in most transmission planning regions are required to have benefits in excess of costs that remain above a certain threshold. The higher perceived uncertainties associated with estimated benefits typically are addressed through benefit-cost thresholds in excess of 1.0 (such as 1.25 in most other regions) and the recognition that many transmission-related benefits may not be quantified. ERCOT's approach of comparing the benefits of a project with 1/6th of the project's construction costs (as an estimate of the project's first year of revenue requirements), consistent with the previously-discussed PUCT order, effectively imposes a benefit-to-cost ratio threshold of 1.30 as discussed below.

However, as shown in Figure 3, the first-year TRR of a transmission project is at its highest relative to the rest of the useful life of the project. Under typical ratemaking treatment of transmission costs, a project's first year TRR is approximately 30% higher than the levelized value of these TRRs over the project life that yields the same present value as the actual declining profile of TRRs. Thus, comparing levelized benefits to 1/6th of the project's construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceeds 1.3 from a present value perspective. We do not advise modifying this criterion at this point, but recommend that ERCOT also calculate a project's benefit-cost ratio based on levelized benefits and levelized costs to recognize the extent to which this approach requires that the value of estimated benefits exceed estimated costs.

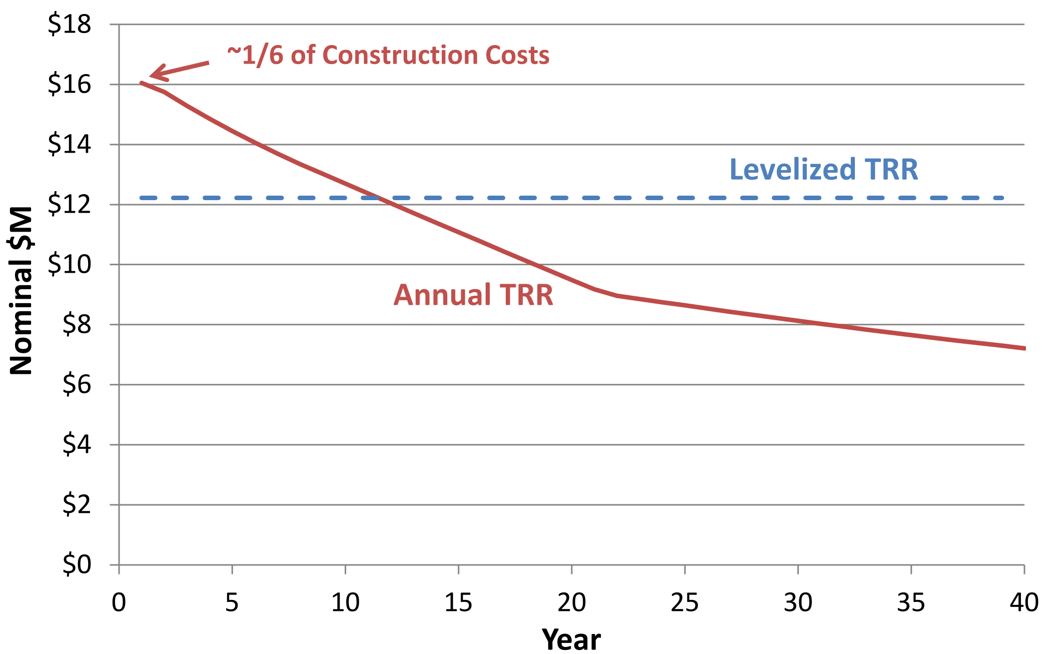
As shown in Figure 4 for a hypothetical \$100 million transmission project, the TRR of a transmission project is at its highest in the first year relative to the rest of the useful life of the project. As a result, the first-year TRR is also higher than the levelized TRR.[47] As shown, when

46 Other transmission planning organizations use the following time horizons to calculate benefit: SPP (which operates a portion of the power grid in Texas) 40 years; MISO (which will soon operate the Entergy portion of the Texas grid) 20 and 40 years; NYISO 10 years; PJM 15 years; ISO-NE 10 years; and CAISO 40 years for upgrades to existing facilities and 50 years for new facilities.

47 Under "cost-of-service regulation," the annual cost of transmission is calculated as an asset's TRR, which is determined based on each project's (straight-line) depreciation, return on ratebase, taxes, and operation

applying typical ratemaking treatment of transmission costs, a project's estimated first year TRR is approximately 30% higher than the levelized value of these TRRs over the project life.[48] Thus, comparing an economic project's levelized benefits to 1/6th of the project's construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceed 1.3 from a present value perspective. We recommend maintaining this approach, recognizing that it imposes a threshold that requires estimated benefits exceed estimated costs by at least 30%.

Figure 4
Transmission Revenue Requirements for Hypothetical $100 Million Transmission Project



2. Case Study of an NVP and Levelized Benefit-Cost Analysis

To illustrate the application of utilizing net present values or levelized benefits and costs in the evaluation of economic projects, we jointly developed with ERCOT staff a realistic example of an economic project E1 that could be built in 2017 for an estimated cost of $291 million. As of

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and maintenance costs. In this example, the accumulation of the benefit from accelerated tax depreciation (relative to straight-line regulatory depreciation) makes the TRRs decline faster over the initial twenty years of a project.

48 Estimating the first year revenue requirements using the 1/6th method can result in a value that is 25–40% higher than levelized costs depending on the depreciation, capital structure, taxes, and O&M costs of any particular transmission project. TXU Energy estimated the value to be 25% in a recent PUCT filing concerning the comparison of project costs and benefits in the analysis of economic projects in ERCOT. (TXU Energy, 2013)

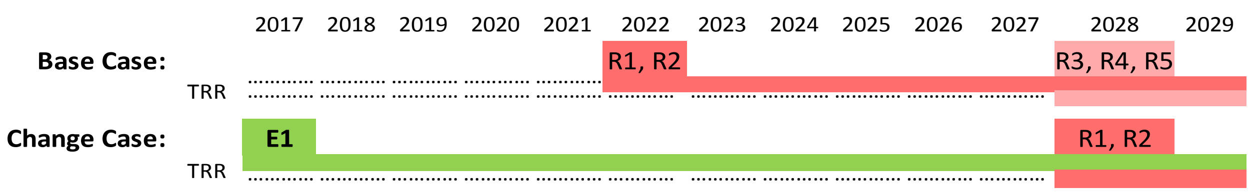
2017, the 40-year present value of the economic project's revenue requirement was estimated to be $465 million.

The timeline of various baseline reliability projects that would need to be built in the Base Case (without the economic project) is shown in the top portion of Figure 5; the timeline of constructing the economic project and the alternative set of reliability projects needed in the Change Case (with the economic project) is shown in the bottom half of Figure 5.

As shown, the Base Case (without the economic project) requires the construction of five baseline reliability projects, two of which will be required in 2022 (R1 and R2) for a cost of $90 million and another three reliability projects (R3, R4, and R5) that would be required in 2028 for a cost of $321 million. The figure illustrates that adding these reliability projects in 2022 and 2028 would be associated with additional annual transmission revenue requirements starting in these years and lasting throughout the useful life of these assets. As of 2017, the 40-year present value of the Base Case reliability projects' revenue requirement was estimated to be $308 million.

Using market simulations, ERCOT staff determined that the addition of the economic project (E) in 2017 in the Change Case would defer reliability projects R1 and R2 for six years to 2028 and avoid the reliability upgrades R3, R4, and R5 completely. As of 2017, the 40-year present value of the Change Case reliability projects' revenue requirement (*i.e.*, only for R1 and R2 built in 2028) was estimated to be $67 million.

Figure 5
Example of an Economic Project E1 Planned for 2017



The comparison of Change Case and Base Case costs thus shows that building the economic project in 2017 and incurring $465 million in present value of TRR is offset by a $241 million present value in lower TRRs for avoided or deferred reliability projects. These reliability project cost savings in (2017 dollars) are equal to the difference between a 40-year present value of $308 million for reliability projects in the Base Case and a 40-year present value of $67 million in the Change Case). As also shown in Figure 5, these avoided and deferred reliability project cost savings are the result of: (1) the avoided annual Base Case costs of R1 and R2 during 2022 through 2027; and (2) having to pay for R1 and R2 while avoiding R3 through R5 starting in 2028. The annual values of these savings (starting in 2022 and increasing in 2028) are shown in Figure 6, in combination with estimated annual production cost savings.

The cost of the economic project net of the reliability project cost savings is thus $223 million in 2017 present value terms. These net costs will have to be more than offset by other economic benefits of the project, such as production cost savings.

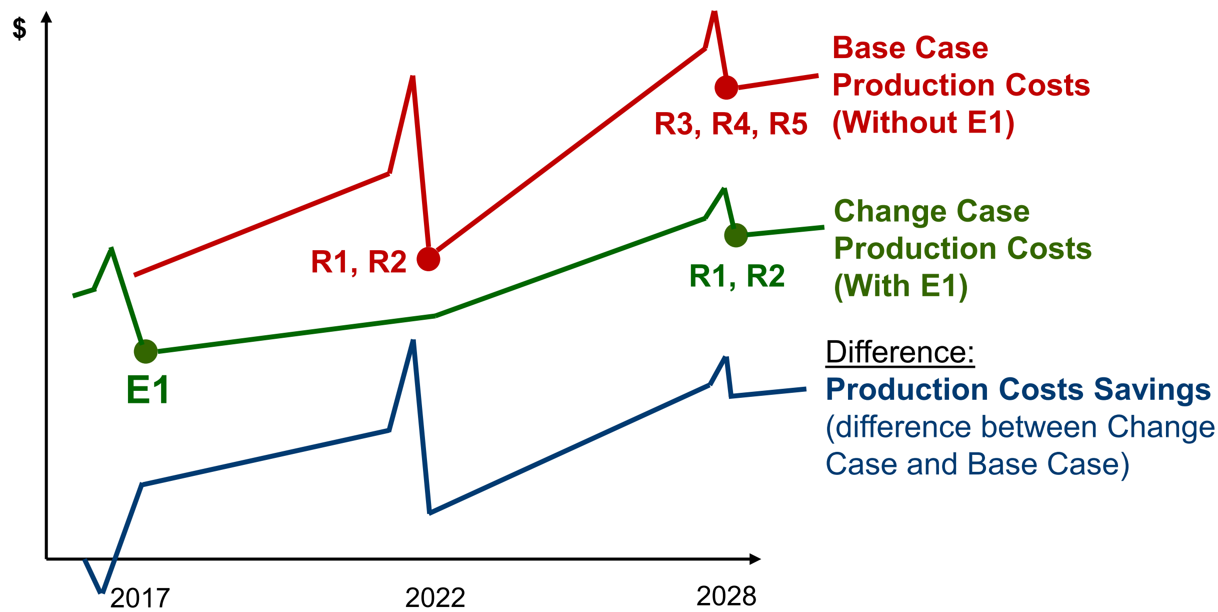
To estimate the value of production cost savings offered by the economic project requires simulation of total annual production costs for both the Base and the Change Cases. The difference between the two streams of production cost will determine the production cost savings of the economic project.

The expected shape of production costs for the Base Case (red line) and Change Case (green line) over time are demonstrated in Figure 6. Using the Base Case (red line) as an example, production costs are expected to rise over time due to increases in fuel costs and load growth. When R1 and R2 are installed in 2022, production costs may temporarily spike due to the transmission outages required to bring the new lines onto the network. Once R1 and R2 are on-line, however, production costs are expected to drop as projects built for reliability proposes often also reduce congestion and associated production costs. While production costs are expected to increase after that, a reduction in these costs must be expected in 2028 after R3, R4, and R5 come online. A similar pattern can be anticipated for the Change Case (green line), but with reduced production costs due to the installation of the economic project in 2017 and the Change Case reliability projects in 2028.

The production cost savings associated with the economic project (production costs in Base Case less the production costs in Change Case) are shown in blue. As shown, these annual values of these production savings first increase as the economic project is added, then further increase due to assumed growth in load and fuel costs. The production cost savings drop temporarily in 2022 when R1 and R2 reduce production costs in the Base Case, but after that, start to increase again with load and fuel costs through 2028. Based on the net effect of the reliability projects added to the Base Case and Change Case the net savings could either increase or decrease in 2028. The 2017 present value of the production cost savings offered by the economic project can be calculated by summing the discounted value of the annual savings represented by the blue line in Figure 6.

Note that Figure 6 also shows short "spikes" in production costs in the year when the new transmission projects are placed in service. These spikes in production costs relate to outages on the existing transmission system that are typically necessary to integrate new projects. They may not be substantial in many cases and are not typically simulated for the purpose of cost-benefit analyses. It is important, however, to keep the possibility of such production cost impacts in mind as new projects are evaluated. These impacts can be very large in cases where the existing system is highly utilized with limited flexibility or long outage durations (*e.g.*, to rebuild an existing line) can make such outages very expensive. Other than illustrating this potential impact in Figure 6, the case study did not further explore these costs and the potentially additional production cost savings associated with Project E1.

Figure 6
Production Costs and Savings from an Economic Project E1 Planned for 2017



To determine the annual values of the production cost savings illustrated in Figure 6 requires, at the minimum, production cost simulations for the Base Case and Change Case for 2017, 2022, and 2028. The annual values for the years between these simulations can then be estimated through interpolations. It is also important to recognize that production cost savings will not drop to zero in 2029. Rather, a more likely trend would be that the 2028 level of production cost savings would increase with load growth and fuel prices. To estimate these increases, the trend between 2022 and 2028 could be extrapolated to estimate these future values. An alternative, more conservative approach would be to assume that 2028 production cost savings will remain constant in real (*i.e.*, inflation adjusted) dollar terms, which would mean that the nominal value of estimated production cost savings would increase only with inflation after 2028. These approaches (or a combination of them) are routinely used by other system operators—such as SPP, MISO, and CAISO[49]—for the purpose of estimating the value of annual benefits over the long-term.

[49] See SPP, 2010, MISO, 2011 and CAISO, 2005 and 2013. For example, to estimate production cost savings for the next 20 to 40 years, MISO interpolated the estimated savings between three simulated years, 2021, 2026, and 2031. MISO also extrapolated the benefit trend estimated for its 2026 and 2031 simulations for another 30 years. SPP's planning process for its Priority Projects estimated benefits for 40 years by simulating the systems for 2009, 2014, and 2019 and extrapolating the 2014–19 trend for another 10 years beyond 2019 before holding annual benefits constant in inflation-adjusted terms until the fortieth year. Similarly, the CAISO used simulations to estimated benefits for planning years 5 and 10, but estimated benefits for the ensuing 35 to 45 years by applying a 1% real escalation rate to planning-year 10 benefits to capture the combined impacts of inflation and other factors on likely future benefits.

The illustration of annual production cost savings in Figure 6 also shows that accurately capturing the value of production cost savings over time may require additional simulation runs. First, to estimate how production cost savings will increase after 2017 (but before they drop once R1 and R2 are added to the Base Case in 2022), it will generally be advisable to either: (a) simulate Base and Change Cases for 2021 and use these estimates to interpolate the years between 2017 and 2021; or (b) simulate a "hypothetical" 2022 Base Case without R1 and R2 and use that case to estimate hypothetical production cost savings for 2022, solely for the purpose of interpolating the value of benefits between 2017 and 2022.[50] The same approach would be necessary for 2027 (option a) or 2028 (option b) to yield more accurate interpolations of production costs savings between 2022 and 2028.

If construction-related transmission outages are anticipated to be significant, these outages would need to be reflected appropriately in both Base and Change Case simulations for 2017, 2022, and 2028 (or any other years during which these outages would occur). In addition, because the outages increase production costs only during the period *prior* to the in-service date of the new transmission project (but not after), the necessary outages may need to be simulated only for the prior years (*i.e.*, 2016, 2021 and 2027) or for "hypothetical" years 2017, 2022, and 2028 that do not yet have the new project placed in service. Our review of industry practice showed, however, that the cost of construction-related outages (or any other outages) to the existing system is not routinely considered in production cost simulations. We thus recommend that any outage-related benefits (or costs) be estimated separately from traditional estimates of production cost savings.

The production costs estimates from the simulations that ERCOT staff performed for this case study are summarized in Table 9. These simulations estimated Base Case production costs (highlighted red) and Change Case production costs (highlighted green) for 2017, 2022, and 2028. In addition, ERCOT staff simulated a "hypothetical" 2022 Base Case (without R1 and R2) and a "hypothetical" 2028 Base Case (with R1 and R2, but without R3, R4, and R5) as a reference point for interpolations between 2017 and 2022 as well as between 2022 and 2028.[51]

[50] The hypothetical 2022 Base Case simulation without R1 and R2 would not be a valid case from a system reliability perspective. This case would be used solely for the purpose of interpolating estimated production cost savings for the years between the 2017 and 2022 simulations. The reliability violations in 2022 without R1 and R2 would only affect a few hours of the year, and thus not distort the accuracy of simulated annual production cost savings.

[51] To summarize, the simulation cases for which production cost savings were estimated by ERCOT staff for the purpose of this case study include the following combinations of reliability and economic projects:

	2017	2022	2028
Base Case	–	R1, R2	R1–R5
Hypothetical Base Case	–	–	R1, R2
Change Case	E1	E1	E1, R1, R2

The annual production cost savings shown in Table 9 are calculated as the difference in estimated annual production costs for the Base Case and the Change Case. As Table 9 shows, the pattern of production cost savings in this case study roughly follows the illustration shown in Figure 6: between 2022 and 2027, production cost savings increase from $32 million to $109 million, before dropping to $90 million in 2022 (after R3, R4, and R5 are added in the Base Case). The same effect exists for 2021–22, although it is much smaller and not as visible in Table 9.

Table 9
Base and Change Case Production Costs
($ millions)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case	$15,233	$15,881	$16,528	$17,176	$17,823	$18,468	$19,084	$19,700	$20,316	$20,932	$21,549	$22,128
Change Case	$15,228	$15,870	$16,511	$17,153	$17,794	$18,436	$19,037	$19,637	$20,238	$20,839	$21,440	$22,038
Savings:	$5	$11	$17	$23	$29	$32	$48	$63	$78	$93	$109	$90

Assuming the estimated production cost savings for 2028 would stay constant in real (inflation-adjusted) dollar terms through 2057, the 40-year present value of the (discounted) annual production cost savings is equal to $859 million. This present value of the economic project's production cost savings compares to the projects $465 million present value of transmission revenue requirements and $241 million in present value of avoided or deferred TRRs of reliability projects. As summarized in Table 10, this yields a total project benefit of at least $1.1 billion (ignoring any other potential benefits), a benefit-cost ratio of 2.4, and a net benefit of $635 million in present value terms (all 2017 dollars). Table 10 also shows that the $1.1 billion present value of benefits is equivalent to levelized annual benefits of $85 million, which compares favorably to both $36 million of the economic project's levelized TRR and $49 million in the economic project's first-year TRR estimated as 1/6th of the project's construction costs. Thus, the project is highly beneficial with societal benefits well in excess of project costs.

Under ERCOT's current approach, the $49 million of the economic project's estimated first-year TRR would have been compared only to 2017 benefits, which are only $5 million in annual production cost savings (since savings from deferred or avoided reliability projects would not be realized before 2022). Thus, while the project is highly beneficial from a long-term value perspective, that value would be foregone under ERCOT's current approach, which would reject the project by comparing only first-year benefits to first-year costs.

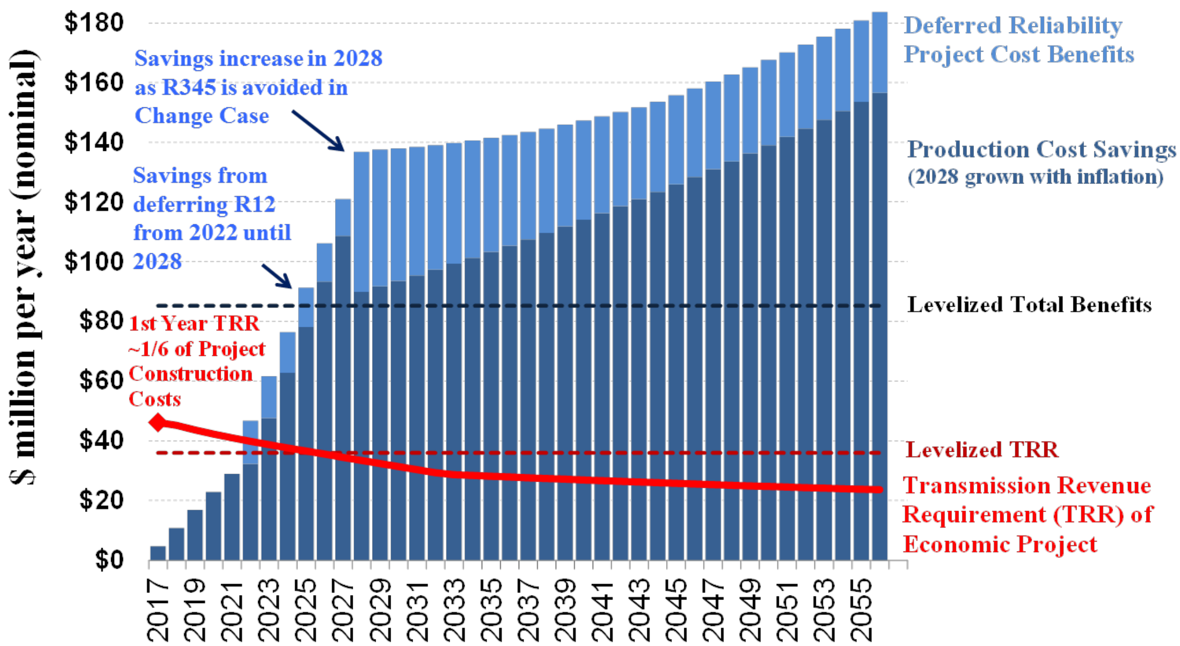
Table 10
Summary of Economic Project Costs and Benefits

		Project Costs ($millions)	40-yr Present Value of TRR ($millions)	Levelized TRR ($millions/yr)	1/6th of Project Costs ($millions/yr)
Economic Project Costs		$291	$465	$36	$49
Economic Project Benefits					
Avoided/deferred Reliability Projects			$241		
Production Cost Savings			$859		
Other benefits			n/a		
Total	Greater than:		$1,100	$85	
Net Benefit			$635		
Benefit-cost Ratio			2.4		

Note, however, that comparing the present value of benefits with the present value of project TRR (or levelized benefits with levelized TRR) is not sufficient to determine if the 2017 assumed in-service date maximizes the value of the economic project. To answer that question, it is also helpful to compare annual project benefits with annual project costs over time. This is done in Figure 7. The annual TRR and levelized TRR of the economic project are shown as solid and dashed red lines. The benefits include both the production cost savings (in dark blue) and the value of deferring or avoiding reliability projects (in light blue). The levelized annual value of the quantified benefits is shown as the dark blue dashed line.

Figure 7 again shows that the $85 million levelized annual value of quantified benefits significantly exceeds both the $36 million levelized TRR of the project as well as the $49 million estimated first-year TRR. The figure also shows that the first year production cost savings of $5 million compare poorly to the first year TRR of $49 million. However, despite the overall positive long-term value of the project, the economic project's quantified benefits do not exceed project TRR until 2022, when production cost savings are higher and the economic project is able to defer reliability upgrades R1 and R2. This means that the long-term value of the economic projects could be increased further by delaying the in-service date of the project until 2022—unless, of course, an earlier in-service data is justified by other benefits that have not been estimated or other considerations that would require the construction of the project prior to 2022.

Figure 7
Summary of Estimated Annual Transmission Benefits and Costs



D. EXPAND THE RANGE OF BENEFITS CONSIDERED AND ESTIMATED IN THE EVALUATION OF ECONOMIC TRANSMISSION PROJECTS

Section V of this report contains the complete discussion and our detailed recommendations concerning benefit metrics for both near-term and long-term implementation. For convenience and completeness, we summarize these recommendations in this discussion of refinements to ERCOT's planning processes. As discussed in Section V, we recommend that ERCOT more fully consider and estimate the economic value of transmission investments in its planning processes. This requires expanding the economic benefits and costs of transmission investments considered. The wider range of benefits will more accurately reflect the value that new transmission can provide to the system. For the most part, this value reflects the higher system wide costs that market participants would be exposed to absent the new transmission.

As it would be difficult for ERCOT to evaluate the complete set of benefit metrics shown in Table 6 for each proposed project, we recommend that ERCOT implement only a subset of these benefits and benefit metrics in the near term. As discussed in Section V, we recommend that ERCOT improve its treatment of production cost savings and the benefits from deferring or avoiding reliability projects. We also recommend that ERCOT add seven economic benefit metrics to its economic evaluation process, two of which would be applied as a typical multiplier to standard estimates of production cost savings. These additional metrics could be applied to each major economic project or portfolios of projects found most promising based on production cost savings and avoided or deferred reliability projects.

The scope of production cost savings, as currently estimated by ERCOT, should be expanded beyond the estimates of savings of a project's first year to include, for example, estimated savings for years 5 and 10 of the project and using these annual estimates to develop estimates for the long-term present value of a project's production cost benefits. The estimated benefit of an economic project's ability to defer or avoid reliability projects should similarly be expanded beyond the project's first year to reflect the present value of reduced or deferred reliability investments.

In terms of additional benefits to be estimated, we recommend that ERCOT: (1) modify its long-term market simulations to capture the impact of forced generation unit outages and ancillary service unit designations; (2) more fully estimate the reduced (or possibly increased) production cost due to project-related changes in transmission losses; (3) study the typical impact of transmission outages on project-related production cost savings to develop a multiplier that could be applied to standard estimates of production cost savings going forward; (4) similarly develop a multiplier to capture the disproportionately higher project-related benefits during weather-related spikes in peak loads; (5) modify simulations to more completely capture cost reductions (or increases) due to a project's impact on the operational cycling of power plants; (6) estimate any decreases (or increases) in installed capacity requirements due to changes in on-peak transmission losses; and (7) more fully consider emission-related costs (including those for long-term risk mitigation benefits).

We further recommend that, at this point, the other benefits in Table 6 be considered, discussed, and analyzed on a case-by-case basis for projects that are anticipated to offer significant value in terms of the individual benefit types. For example, an evaluation of generation cost savings may be undertaken in the future in the context of a transmission project that allows for either the deferral of generation investments (*e.g.*, by allowing plants in neighboring regions with surplus capacity to "switch" into ERCOT) or the development of new generating plants to be shifted from high-cost locations (*e.g.*, areas that have higher land costs or would require greater investment in emission controls) to lower-cost locations. Similarly, project-specific benefits should be evaluated on a case-by-case basis as future projects offer unique benefits, such as opportunities for improved utilization of transmission rights-of-way or the creation of low-cost options for possible future transmission projects.

To implement the recommended additional benefit metrics in the transmission planning process, it will be necessary to develop and refine proposed approaches through the RPG stakeholder process. We also anticipate that stakeholder workshops be used to fully explain the details of each proposed benefit metric and document with case studies how ERCOT has quantified its value. As ERCOT's experience with project-specific additional benefits metrics increases over time, these metrics should then be added to the set of metrics that is routinely considered.

E. Improve Use of Scenarios and Sensitivities

Recognizing the uncertainties about the future, particularly from a long-term perspective, we recommend that ERCOT improve its use of scenarios and sensitivities considered in the long-term planning process. It is important for ERCOT to distinguish in its near- and long-term simulation efforts between the short-term uncertainties that can impact the operation of the transmission network in any future year and the long-term uncertainties that will define the industry in the future. The short-term uncertainties should not be used for defining long-term scenarios, but instead be captured through modeling of the uncertainties within each scenario. The long-term uncertainties on the other hand should be explored and agreed upon through the development of a range of scenarios that reasonably reflect the range of long-term uncertainties.

Stakeholder feedback provided insight into the scenario-development process that had been undertaken in the last two years to create plausible and reasonable scenarios about future market conditions. While having made some significant progress, there are opportunities to meaningfully improve on both the process used to develop the scenarios and how scenario analysis, and the accompanying sensitivity analyses, can be used to improve ERCOT's planning process. It is clear that stakeholders will accept the results of long-term studies more readily if they understand the assumptions embodied in the scenarios and believe they reflect a reasonably complete range of plausible future market conditions.

To further improve the understanding and buy-in of long-term planning efforts, ERCOT should consider refining its stakeholder process for developing scenarios. Based on the experience with ERCOT's recent effort, the next iteration of this process can be defined more clearly from the onset and specify more concisely how scenarios will be used in the long-term planning effort and how long-term planning results will be used in the RTP process. It is important for ERCOT to reiterate its invitation to all potentially interested parties to participate in this process and make clear that stakeholder buy-in for the scenario assumptions and planning effort will lead to "results that matter."

To achieve these goals, we recommend that the scenario development process be a facilitated stakeholder-driven process that includes representatives from each sector within the electric power industry as well as experts from outside of ERCOT and the power industry (such as from the oil and gas sectors) to share their views on the future of the state's economy and energy industry, including their perspectives regarding electricity usages and potential growth for the industry. The scenarios should reflect a wide range of possible future outcomes in terms of ERCOT-wide and localized load growth, generation mix and locations, and fuel prices.

Some stakeholders have raised concerns that transmission investment should not be based on projections of market conditions beyond several years, given the considerable long-term uncertainties faced by the industry. Planners may want to stay away from such investment decisions, fearing that uncertain futures could dramatically change the value of those investments and result in regrets. We believe, however, that the likelihood of inefficient investments or "regrets" is just as high when decisions about long-lived assets are made solely based on near-term considerations. Shying away from making investment decisions because of difficulties in predicting the future could lead to a perpetual focus on transmission upgrades that address only the most urgent near-term needs, such as reliability violations, and thereby forego opportunities to capture higher values by making investments that could address longer-term needs much more effectively. It is also likely to lead to inefficient use of scarce resources, such as available transmission corridors and rights-of-way. To address this challenge, we recommend that ERCOT continue to evaluate long-term uncertainties through scenario-based analyses. Such scenario-based long-term planning approaches are widely used by other industries (such as the oil and gas industry)[52] and have also been employed, for example, by SPP's Integrated Transmission Planning (ITP) and the MISO Transmission Expansion Plan (MTEP) processes.[53] The scenarios specified by SPP and MISO in their 10 to 20 year planning processes take into account (though only to a limited degree) divergent assumptions about renewable energy additions, load levels, and a few other factors.

Evaluating long-term uncertainties through various future scenarios is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can be used to: (1) identify "least-regrets" projects whose value would be robust across most futures; and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values of economic transmission projects under the various scenarios should be used both to assess the robustness of a project's cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

In addition to a scenario-based consideration of long-term uncertainties, we recommend that short-term uncertainties be considered separately. Short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive scenario definitions. These uncertainties should be simulated probabilistically

52 For example, see Royal Dutch Shell, 2013. See also Wilkinson and Kupers, 2013.

53 See, for example, MISO, 2011 and SPP, 2010.

or through sensitivity analyses for each of the chosen scenarios to capture the full range of the societal value of transmission investments.[54]

The simulation of short-term uncertainties can be particularly important because the value of transmission projects is disproportionately higher during more challenging market conditions that are created by such uncertainties. Not analyzing the projects under challenging, but realistic, market conditions risks underestimating their values. The impact of near-term uncertainties can be analyzed by specifying probabilities and correlations for key variables, importance sampling, and undertaking Monte Carlo simulations for the selected set of cases. However, such complex and time-consuming probabilistic simulations are not always necessary. Often, a limited set of sensitivity cases (*e.g.*, 90/10, 50/50, 10/90 load forecasts) and case studies (*e.g.*, simulating past extreme contingencies, outages, weather patterns) can serve as an important step toward capturing the actual values of projects, which can help planners better understand how these near-term uncertainties can affect the expected value of projects in any particular future year.

For example, to address how uncertainties affect the value of transmission projects, the California Energy Commission developed a framework for assessing the expected value of new transmission facilities under a range of uncertain variables. Their recommended approach identifies the key variables that are expected to have a significant impact on economic benefits, establishes a range of values to be analyzed for each variable, and creates cases that focus on the most relevant sets of values for further analysis, including the probabilities for each case.[55] As Luminant pointed out, ERCOT also previously performed simulations for normal, higher-than-normal, and lower-than-normal levels of loads and natural gas prices in its evaluation of the Houston Import Project. The simulations showed that a $45.3 million annual consumer benefit for the Base Case simulation (normal load and gas prices) compared to a $52.8 million probability-weighted average of benefits for all simulated load and gas price conditions,[56] illustrating the extent to which the value of transmission projects can depend on the consideration of key uncertainties.

F. Enhance Economic Project and Benefits/Costs Identification Process

Finally, we recommend that ERCOT refine its process for identifying candidate economic transmission projects and their expected societal benefits and costs. The transmission planning process and the considerations for transmission-related benefits go hand in hand. The choice of what projects to pursue is directly linked to how planners and developers view the need for

54 For simplified frameworks taking into account both long-term and short-term uncertainties for transmission planning in the context of renewable generation expansion, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

55 Toolsen, 2005.

56 ERCOT, 2011a, p. 10.

transmission projects and, thereby, the potential benefits that these projects would provide. Through our experience we have found that a successful approach to the identification of potentially beneficial projects and their benefits is to consider qualitatively all the potential benefits offered by the contemplated transmission investments at the outset, when assessing the need of certain projects. Putting all the benefits on the table upfront helps avoid encumbering the overall planning process by focusing too early on time-consuming market simulations that may not even be able to capture many of the identified benefits.

We thus recommend that ERCOT consider supplementing its planning efforts with a structured process that allows market participants to propose candidate economic projects and identify their anticipated benefits. For example, under this process ERCOT could gather system planners, project developers, and other stakeholders to identify *potential* transmission projects that could supplement or replace baseline reliability projects and develop a comprehensive list of their likely benefits. This project identification effort would be facilitated by ERCOT and involve market participants to provide information about existing and anticipated system conditions. The participants would propose and document project ideas while simultaneously describing the projects' anticipated benefits—without limitations imposed by available analytical frameworks. The goal of this effort is to identify a wide range of possible projects that could more efficiently address reliability needs, meet public policy objectives, and offer economic benefits without impeding or limiting the scope of options and benefits considered at the outset. The only two questions that should be asked at this stage of the process are: (a) what transmission projects would likely be beneficial in addition to or instead of those that have been identified to meet reliability standards? and (b) what are the likely types of benefits that these projects would offer and why are they expected to be significant?

Even if the values of some benefits are not easily estimated with existing tools, they should still be considered and at least discussed qualitatively. Once proposed projects and their likely benefits have been specified, ERCOT will need to prioritize the proposed projects based on the stakeholder input and undertake benefit-cost analysis based on available analytical capabilities to determine whether a proposed project meets its economic planning requirements. As discussed in Section V of this report, some of the identified economic benefits can be measured readily through traditional benefit metrics, such as production cost or avoided reliability project cost savings. These traditional benefit metrics would be analyzed for every project or portfolio of projects through a refined existing framework within each planning cycle. Other benefits may not lend themselves to routine analyses through formulaic benefit metrics. The value of those benefits would be estimated when the anticipated magnitude is significant such that it could materially affect the attractiveness of the proposed projects. Benefits which could be significant but are more difficult to estimate should be analyzed by estimating at least their likely range and magnitudes—rather than implicitly assuming that they have zero value only because their precise values are difficult to calculate. Benefits that are unique to specific projects could be assessed only if and when they are applicable. This project evaluation step is also the step where non-transmission alternatives should be considered when comparing benefits and costs of proposed projects.

We have also found that, while it is intuitive to estimate the economic benefits associated with every proposed transmission project, often several projects could be considered jointly because the combination of the projects can provide higher (or in some cases lower) benefits than the sum of each project's individual benefits. By analogy, a particular section of the interstate highway system might have little value unless it is integrated with the rest of the system. Likewise, a group of transmission facilities may provide substantially greater system-wide benefits than the sum of the benefits for each individual segment that makes up the group. On the other hand, competing or conflicting projects would need to be evaluated independently. Such distinction reinforces the need to describe and understand the potential benefits of each project upfront before delving into the quantitative analyses. If a group of facilities can offer more benefits jointly than independently, developing efficient portfolios of transmission projects would require iterative analyses of several transmission options and non-transmission alternatives in this step.

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APPENDIX A – TYPES OF TRANSMISSION BENEFITS AND THE IMPORTANCE TO CONSIDER A COMPLETE SET OF BENEFITS

As is generally understood at least conceptually, transmission investments can support a wide range of benefits. The most common benefits include increased reliability, decreased transmission congestion, renewables integration, reduced losses, reduced resource adequacy requirements, and increased competition in power markets. Some of these benefits spread across wide geographic regions and multiple utility service areas and states, and can significantly affect market participants ranging from generators to retail electricity customers. Over the long-life of the transmission assets, the nature and the magnitude of the benefits can also change significantly. For example, benefits associated with today's transmission grid, such as the ability to operate competitive wholesale electricity markets, could hardly have been imagined or estimated when the facilities were built four or five decades ago, long before the advent of open access to the transmission grid.

Recent transmission planning experiences have also shown that the scope of transmission-related benefits generally extends beyond the main driver of a particular project. While many transmission investments are motivated by a single driver—such as reliability, congestion relief, or renewable generation integration—the benefits of these transmission investments generally extend beyond the individual driver. For example, many reliability-driven projects also will reduce congestion and support the integration of renewable generation. Similarly, a transmission project driven by congestion-relief objectives also will also increase system reliability, help to avoid or delay reliability projects that would otherwise be needed in the future, or reduce system-wide investment needs by allowing access to lower-cost generation resources. This multi-purpose, multi-value aspect of transmission investments requires a more systematic analysis of the wide range of transmission-related benefits and the interaction of transmission investments with other system-wide costs and non-transmission investments.

A. PRODUCTION COST SAVINGS AS A TRADITIONAL BENEFIT METRIC

The most commonly-considered economic benefits of transmission investments are estimated reductions in simulated fuel and other variable operating costs of power generation (generally referred to as production cost savings) and the impact on wholesale electricity market prices (in many cases referred to as locational marginal prices or LMPs) at load-serving locations of the grid. These **production cost savings** and **load LMP benefits** are typically estimated with production cost models that in order to streamline the modeling effort are configured to simulate generation dispatch and transmission congestion based on simplified approximations of power flows, predefined transmission constraints, and normalized system conditions.

In a recent assessment of RTO performance by FERC, the majority of RTOs cited congestion relieffs as a main benefit from expanding transmission capacity. For example, PJM noted that market simulations of recently-approved high-voltage upgrades indicate that these upgrades will reduce congestion charges by approximately $1.7 billion compared to congestion charges without the upgrades.[57] While changes in total congestion charges are informative, the economic value of such congestion relieve is generally reflected in production cost savings (from an economy-wide perspective) and load LMP benefits (from the perspective of customers in restructured retail electricity markets) because a reduction in congestion typically increases the use of more efficient (lower cost) generators over the inefficient (higher cost) ones.

Since production cost simulations have become a standard tool for many transmission developers and grid operators, production cost savings estimation is the analysis that can readily be repeated for all proposed transmission projects or groups of projects. While production cost savings are readily estimated (based on assumptions), the results only provide estimates of the short-term dispatch-cost savings of system operations. These savings are only a portion of the overall economic benefits provided by transmission investments and do not capture a wide range of other transmission-related benefits, including many long-term capital and operational cost savings. For example, as a Western Electric Coordinating Council (WECC) planning group recognized:

> The real societal [*i.e.*, overall economic] benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost simulation] analysis.[58]

In addition, as explained in more detail in Appendix B, production cost simulations as traditionally undertaken are based on a number of simplified assumptions that can significantly understate the derived estimates of production cost savings.

B. EXAMPLES OF A MORE FULLY ARTICULATED SET OF TRANSMISSION BENEFITS

Aside from production cost savings, other benefits—particularly those associated with improved reliability, reduced generation capital costs, reduced market power and demand—are often omitted in many transmission benefit-cost analyses. These omitted benefits are sometimes inaccurately viewed as "soft" or "intangible" benefits simply because they are not yet routinely estimated by transmission owners and system operators. Even though some of these additional benefits can be difficult to estimate in certain situations, omitting them effectively assumes these benefits are zero, which may not be the case.

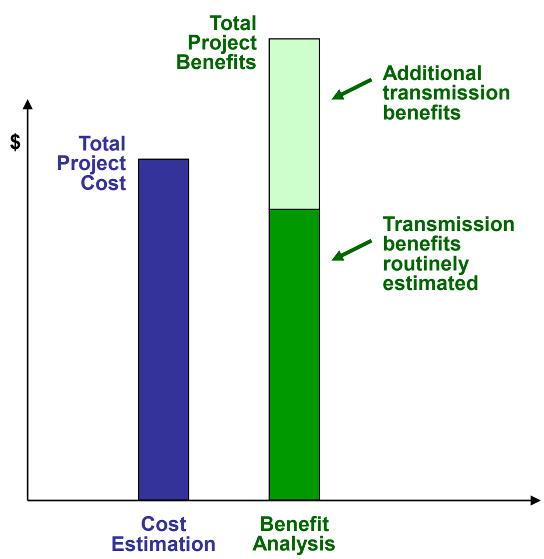
[57] FERC Performance Metrics, 2011, Appendix H: PJM, p. 275. Additionally, an 82% reduction in annual congestion costs is forecast from $980 million "as is" 2012 baseline to $173 million "as planned" based on PJM's 2016 RTEP (Cash, 2013).

[58] SSG-WI Transmission Report, 2003.

Instead of assuming some of the more difficult to estimate benefits have a zero value, estimating the approximate range of likely benefits will yield a more accurate benefit-cost analysis and provide more insightful comparisons that avoid rejecting beneficial transmission investments. For example, transmission lines can increase competition in wholesale electricity markets as more generators gain access to a wider set of customers. In some cases, transmission upgrades can reduce a region's resource adequacy needs and offer access to lower-cost generating resources. While estimates of resource adequacy or competitive benefits might not be precise at times, rough estimates of the likely magnitude of these benefits can generally be developed. As conceptually illustrated in Figure 8, overlooking or ignoring such difficult-to-quantify or not-commonly-estimated benefits can lead to rejection of otherwise desirable projects. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to not considering all costs and the potentially very-high-cost outcomes that market participants would be exposed to in the absence of these investments.

In other words, being "conservative" and to understate the likely value of the economic benefits of transmission investments means to be conservative in estimating likely future costs imposed on customers and society as a whole in the absence of the project. Thus, unbiased estimates of all benefits that are neither too conservative nor too optimistic will yield better investment decisions and more efficient, lower-cost outcomes in the long term.

Figure 8



As we noted in a prior report for WIRES,[59] the post-construction assessment of the Arrowhead-Weston transmission line in Wisconsin, developed by American Transmission Company (ATC)

59 Pfeifenberger and Hou, 2011, Section IV.

in 2008, provides a good example of the broad range of benefits associated with that project. The primary driver of the Arrowhead-Weston line was to increase reliability in northwestern and central Wisconsin by adding another high voltage transmission line in what the federal government designated at the time as "the second-most constrained transmission system interface in the country."[60] The project addressed this **reliability** issue by adding 600 MW of carrying capacity and improving voltage support, the impact of which was noticeable in both Wisconsin and in southeastern Minnesota. By also **reducing congestion**, ATC estimated that the line allowed Wisconsin utilities to decrease their power purchase costs by $5.1 million annually, saving $94 million in net present value terms over the ensuing 40 years. Similarly, ATC estimated that the project saved $1.2 million in **reduced costs for scheduled maintenance**. The high voltage of the line (345 kV) also **reduced on-peak energy losses** on the system by 35 MW, which **reduced new generation investments** equivalent to a 40 MW power plant. The reduced losses also avoid generating 5.7 million MWh of electricity that would **reduce CO_2 emissions** by 5.3 million tons over the initial 40-year life of the facility. In addition, the transmission line has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to **help Wisconsin meet its RPS requirements**. The construction of the line **supported 2,560 jobs**, generated $9.5 million in **tax revenue**, created $464 million in total **economic stimulus**, and will provide $62 million of **income to local communities** over the next 40 years. The increased reliability of the electric system has provided **economic development benefits** by improving the operations of existing commercial and industrial customers and attracting new customers. Lastly, the project also provided **insurance value against extreme market conditions** as was illustrated in a North American Electric Reliability Corporation (NERC) report which noted that if the Arrowhead-Weston line had been in service earlier, it would have **averted blackouts** in the region which impacted an area that stretched from Wisconsin and Minnesota to western Ontario and Saskatchewan, affecting hundreds of thousands of customers.

Figure 9 and Figure 10 summarize examples of transmission benefit-cost analyses that identified and estimated a number of the transmission-related benefits discussed above. As shown, the examples show projects that provide benefits significantly in excess of transmission-related rate increases, with the estimated economic benefits exceeding their costs by 60% to 70%. These examples also show that the traditionally estimated production cost savings are only a portion of the total benefits.

A comprehensive analysis of a broad range of transmission-related benefits also may show that some benefits have negative values (i.e., representing costs). For example, transmission investments that help integrate lower-cost but distant generating resources also can increase system-wide transmission losses. Some transmission expansions can lead to increased emissions

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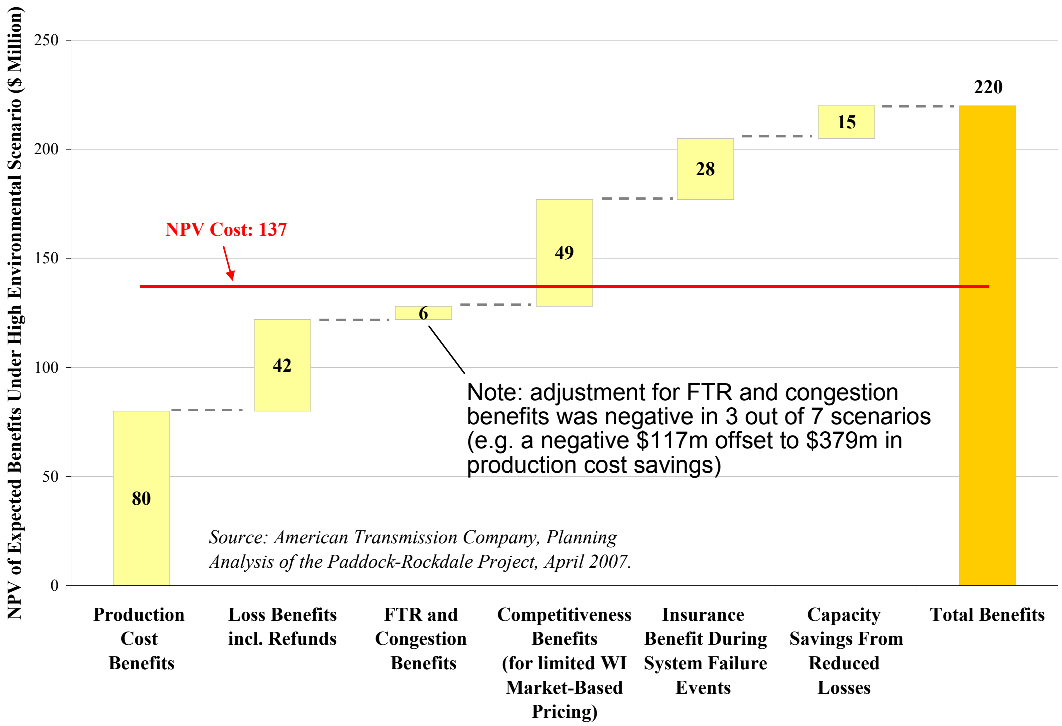
[60] ATC (2009), p. 7.

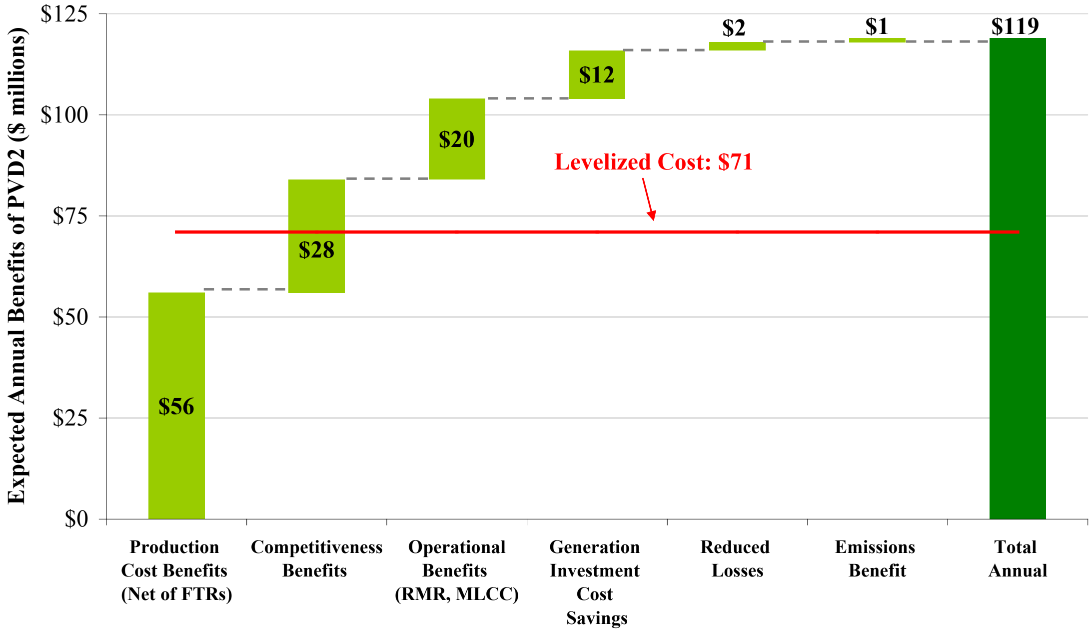
and associated environmental costs; or certain transmission projects may cause larger environmental impacts in terms of their land use. From a consumer perspective, new transmission could decrease the value of existing physical or financial transmission rights, thereby offsetting benefits related to congestion relief or the increased availability of transmission rights.[61]

Figure 9
Total Benefits Quantified for ATC's Paddock-Rockdale Project



61 The economic analysis of the Paddock-Rockdale Project is a good example of transmission benefits that could be positive or negative. We have presented in Figure 9 the summary results of one of the seven scenarios examined when ATC evaluated the project. In Figure 9, we show that additional "FTR and Congestion Benefits" added $6 million to the savings of the project. However, the results for the other Scenarios analyzed by ATC showed different patterns. Specifically, the "FTR and Congestion Benefits" was actually negative in three of the seven scenarios. In fact, it had a negative value of $117 million in one of them, which offset $379 million in production cost savings for that scenario. These results also document that benefits can vary greatly across possible different futures, which illustrates the importance of scenario analysis to evaluate the robustness of project economics as we discuss further below.

Figure 10
Total Benefits Quantified for Southern California Edison's Palo Verde-Devers 2 Project



Source: CAISO PVD2 Report, 2005.

APPENDIX B – EXPERIENCE WITH IDENTIFYING AND ANALYZING A BROAD RANGE OF TRANSMISSION BENEFITS

This appendix to the report presents a technical discussion of the full range of the economic benefits of transmission investments identified in Table ES-1 and Table 6 of the main report and summarizes the available industry experience on how they are estimated. It also documents current industry practices in the analysis of these benefits, describes in detail how certain benefits not traditionally quantified by ERCOT can be measured, and explains why they can be important in assessing the benefit-cost impact of proposed transmission projects. Consistent with Table ES-1 and Table 6, the transmission benefits discussed in more detail include:

1. Production cost savings;
2. Reliability and resource adequacy benefits;
3. Generation capacity cost savings;
4. Market benefits, such as improved competition and market liquidity;
5. Environmental benefits;
6. Public policy benefits;
7. Employment and economic development benefits; and
8. Other project-specific benefits such as storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits.

The remainder of this appendix first presents these benefit metrics, their descriptions and industry experiences in the summary tables on the following pages. These summary tables are then followed by a narrative discussion. This appendix is largely based on Section VI of our recently-published report *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for WIRES in July 2013. The research conducted for Section VI in the WIRES report was conducted in parallel to our engagement with ERCOT, with both engagements benefiting from the synergies of the two efforts. Some of the discussion in this appendix and the WIRES section also is based on a report prepared by the SPP Metrics Task Force (*Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012), which we helped prepare.

1. Additional Production Cost Savings				
	Transmission Benefit	**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
1. Additional Production Cost Savings				
a.	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
b.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
c.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
d.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
e.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
f.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	
g.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study
h.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
i.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)

2–3. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings				
Transmission Benefit		**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability Or:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3. Generation Investment Cost Savings				
a.	Generation investment cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4–7. Market, Environmental, Public Policy, and Economic Stimulus Benefits				
Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	
6.	**Public Policy Benefits**	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7.	**Employment and Economic Development Benefits**	Increased full-time equivalent (FTE) years of employment, economic activity related to new transmission line, and tax revenues	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

8. Other Project-Specific Benefits				
	Transmission Benefit	**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
8. Other Project-Specific Benefits				
a.	Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
b.	Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
c.	Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
d.	Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
e.	Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
f.	Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
g.	Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

A. PRODUCTION COST SAVINGS

The most commonly used metric for measuring the economic benefits of transmission investments is the reductions in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

1. Definition and Method of Calculating Production Cost Savings

Within production cost models, changes in system-wide production costs can be estimated readily. The traditional method for estimating the changes in production costs associated with a proposed transmission project is to compare the production costs (or "adjusted production costs")[62] with and without the transmission project. Analysts typically call the market simulations without the transmission project the "Base Case" and the simulations with the transmission project the "Change Case."

These simulations can also provide estimates of how the proposed transmission projects affect the pattern of transmission congestion, the overall production costs necessary to serve load, the prices that utilities (and ultimately their customers) pay for market-based energy purchases, and the revenues that generators receive for market-based energy sales. Thus, through production

[62] These estimated changes in production costs, however, do not necessarily capture how costs change within individual regions if there are purchases and sales from neighboring regions. This is because the cost of serving these regions and areas will not only depend on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. Such purchases or sales to neighboring regions has not been a consideration within ERCOT, which is very weakly interconnected with other regions. If transmission projects will be evaluated in the future that may increase exports from or into ERCOT, the system-wide production costs within ERCOT would need to be "adjusted" for such purchases and sales. This can be approximated through a widely-used benefit metric referred to as Adjusted Production Costs (APC).

Adjusted production costs for an individual utility are typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility's market-based power purchases and sales. For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs of the utility's load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility's generation locations (Gen LMP).

cost simulations, one can quantify the direction and magnitude of both cost and price changes by comparing the results from the Change Case with those from the Base Case.

For example, SPP estimated that its Priorities Projects will result in $1.3 billion of production cost savings. This amount of production cost savings is equal to approximately 62% of the estimated costs of the transmission projects that enable those savings.[63]

2. Limitations of Production Cost Simulations and Estimated APC Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners, including other system operators in Texas and neighboring regions, are increasingly recognizing that traditional production cost simulations are limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by necessary simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. In most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Weather-normalized peak loads and monthly energy (*i.e.*, no extreme weather conditions);
- Perfect foresight of all real-time market conditions;
- Incomplete plant cycling costs;
- Over-simplified modeling of ancillary service-related costs;
- Incomplete simulation of reliability must-run conditions;

In some cases, such as ERCOT's simulations undertaken for its long-term planning process, we also have observed that market simulations did not consider forced generation outages.

We discuss each of the common limitations listed above in Subsections 3 through 10, and provide examples of how the components of production cost savings that are not captured due to these simplifying assumptions can be or have been estimated.[64] Following that, Subsection 12 discusses how adjusted production cost calculations (if they were to be used by ERCOT in the future) simplify the estimated charges for congestion and marginal transmission losses, which can result in the under- or over-estimation of transmission-related benefits.

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[63] SPP, 2010, p. 26.

[64] See *also ibid.*, Section 4.

3. Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.[65] Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.[66] Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.[67] For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional $11 to 29 million in annual savings compared to the older technology.[68]

4. Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the

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65 For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see *ibid.*, Section 4.2. See also Pfeifenberger Direct Testimony, 2008.

66 ATC, 2007, pp. 4 (project cost) and 63 (losses benefit).

67 Pioneer, 2009, at p. 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

68 Pfeifenberger and Newell Direct Testimony, 2011.

value of transmission upgrades and additions because outages, when they occur, typically cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[69]

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.[70] Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.[71] MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to account for unmodeled events such as unplanned transmission outages and loop flows.[72] As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and west-east price differentials.[73] These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the

[69] For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see SPP, 2010, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

[70] PJM FTR Report 2012, p. 32. See also PJM FTR Presentation, 2011.

[71] Patton, 2011.

[72] See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manuals. Posted at: https://www.midwestiso.org/LIBRARY/BUSINESSPRACTICESMANUALS/Pages/BusinessPracticesManuals.aspx.

[73] Pfeifenberger and Newell, 2006.

extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than \$10 million a year, with PJM's Load locational pricing payments decreasing by more than \$40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.[74]

Our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (*e.g.*, peak load) conditions.[75] Higher additional transmission–outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (*i.e.*, not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month period.[76] The TSM report also showed that, for the five most constrained flowgates on the Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This also indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

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74 Pfeifenberger and Newell Direct Testimony, 2011.

75 Pfeifenberger, *et al.*, 2013.

76 Potomac Economics (2013).

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

5. Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[77]

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San

[77] ATC, 2007, pp. 4 (project cost) and 50-53 (insurance benefit).

Onofre outage.[78] This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.[79]

Further, the analysis of high-impact, low-probability events also documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only $77 million for 2013—there was a 10% probability that the annual benefit would exceed $190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between $360 and $517 million.[80]

6. Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.[81]

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.[82] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions. While it is difficult to estimate how often such conditions might occur in the future, they do

78 CPUC *Opinion*, 2007, pp. 37–41.

79 See Wald, 2013.

80 CAISO PVD2 Report, 2005, p. 24.

81 Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

82 See SPP, 2012, Section 9.6.

occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the base case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[83]

7. Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.[84] From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and

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83 ERCOT, 2011a, p. 10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

84 Pfeifenberger and Newell Direct Testimony, 2011.

prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.[85] These benefits will generally be more significant if transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[86]

8. Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about $200/MW per start (with a

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85 For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from $5.77 to $8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between $2.26/MWh and $2.84/MWh, while within-day variability accounts for $2.93/MWh to $5.74/MWh of wind energy injected. See EnerNex, 2013 ($/MWh in US$2024).

86 For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

range between $160/MW and $260/MW). The costs associated with equipment damage account for more than 80% of this total.[87]

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP's Metrics Task Force recently suggested that production simulations be developed and tested,[88] this is an area where standard analytical methodology still needs to be developed.

9. Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis, finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of $28 to $87 million, or less than one percent of the cost of the transmission projects evaluated.[89] In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may

87 See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from $2008 to $2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

88 SPP, 2012, Section 9.4.

89 MISO, 2011, pp. 29-33.

be significantly larger. However, to quantify these benefits often requires specialized simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements. Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

10. Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such "reliability must run" (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately $50 million to $100 million per year.[90] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

11. Estimating Societal Benefits versus Electricity-Customer Savings

System-wide production cost savings from the simulations of transmission investments as discussed in this section represent economy-wide societal benefits. In a regulatory environment where all generation is cost-of-service regulated with no market-based purchases and off-system sales, these system-wide savings would also reflect customer benefits for the entire simulated

90 Pfeifenberger Direct Testimony, 2012, pp. 48-49.

footprint—which usually includes all neighboring regions. To measure transmission-related benefits to an individual region, individual utilities, or other load-serving entities (LSEs), analysts typically rely on metrics such as Adjusted Production Costs (APC) and Load LMP costs. As noted above, these metrics can approximate electricity-customer benefits but they differ from the magnitude of societal benefits. The magnitude of these benefits depends on assumptions about market structure and the extent to which LSEs would be exposed to cost-based generation, market-based purchases and sales, and (within RTO markets) marginal loss charges and unhedged congestion charges.

For example, the APC metric measures the change in variable costs of generation within (or contracted to) an LSE's service area, adjusted for market-based purchases and sales. As a measure of customer impacts, the metric approximates customer costs for a vertically-integrated, cost-of-service regulated utility environment, consistent with simplifying assumptions that: (1) all owned or contracted resources supply power at variable production costs; (2) all imports and other non-cost-based purchases are market-based, priced at the area's internal Load LMP (*i.e.*, no fixed-priced contracts and assuming congestion charges for imports and purchases could not be hedged with allocated FTRs); (3) all off-system sales from an LSE's cost-based resources are priced at the area-internal Generation LMP; (4) no congestion costs charges are incurred in transmitting energy from cost-based generation to load within the LSE's service area (*i.e.*, all transactions from cost-based resources are fully hedged with allocated FTRs); and (5) no marginal loss charges are incurred on transactions from cost-based resources.

The load-weighted LMP metric measures the change in market-based power purchase costs that would be paid by customers in an LSE's service area if all load was served at LMPs at the load's location. This metric thus approximates customer impacts in a retail access environment, implicitly reflecting an assumption that all load is served at market prices without any cost-of-service-based generation, long-term contracts, FTR allocations that would hedge congestion charges, or the partial refunds of marginal-loss-related charges.

Because some RTO service areas cover both cost-of-service regulated, vertically-integrated utilities as well as LSEs that supply customers through market-based purchases, both APC and Load LMP metrics may be relevant. In fact, PJM has defined a blended metric based on a 70% APC and 30% Load-LMP weighted average. This hybrid metric roughly represents a market structure under which retail rates reflect roughly 70% cost-based generation that is fully hedged against congestion charges and 30% market-based generation (including imports) that is entirely unhedged through FTR allocations.[91]

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[91] MISO also previously used this hybrid (70%/30%) metric for production cost savings but has changed to a 100% Adjusted Production Cost Savings metric as they have found it better represents their load characteristics (MISO, 2012).

While these metrics and the simplifying assumptions used to derive them will be sufficient in many cases, a more accurate calculation of customer impacts for individual utilities or LSEs may be necessary because these traditional metrics do not explicitly take into account a number of energy and congestion-related factors that can be important in estimating the impacts of transmission investments from a customer-cost perspective. In particular, they may need to be modified to more accurately account for: (1) the degree of cost-based versus market-based generation; (2) long-term contracts and their pricing (*e.g.*, variable-cost based, fixed, or market-based); (3) the level of FTR coverage for a service area's internal and contracted generation; (4) the level of FTR coverage for imports into the service area; (5) the extent to which the transmission projects make additional FTRs available to LSEs in the service area; and (6) the difference between marginal loss charges, loss refunds, and the simulation's treatment of energy losses.[92]

B. Reliability and Resource Adequacy Benefits of Transmission Projects

This and the following subsections of this appendix address transmission-related benefits that are not reflected in production cost savings. As noted earlier, production cost savings only measure the reduction in variable production costs, including fuel, variable O&M costs, and emission costs.[93] This means that production cost savings, even if the simulations capture the additional factors discussed above, will not capture the benefits associated with reliability, capital costs, increased competition, certain environmental benefits and other public policy benefits, or economic development benefits. These benefits provide additional value to electricity customers and to the economy as a whole.

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example, additional transmission investment made for market efficiency and public policy goals can avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

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92 For an example of more detailed estimates of customer impacts, see Pfeifenberger Direct Testimony, 2008.

93 Emissions costs are only considered to the extent that the simulations assume a price for emissions such as SO_2, NO_x, and in some cases CO_2.

1. Benefits from Avoided or Deferred Reliability Projects

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs may be avoided or could be deferred for a number of years. As is already largely reflected in ERCOT's planning process, these avoided or deferred reliability upgrades effectively reduce the net cost of planned economic or public-policy projects. The long-term benefits can be estimated by comparing over time the revenue requirements of reliability-based transmission upgrades without the proposed project (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed project would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (*i.e.*, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.[94] Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be $357 million, or 25% of the costs of the proposed new transmission projects.[95] This method has also been used by MISO, who found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.[96]

2. Benefits of Reduced Loss of Load Probability <u>or</u> Reduced Planning Reserve Margin Requirements

Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on higher-cost measures to avoid shedding load (a production cost benefit considered in the

[94] See SPP, 2012, Section 3.3.

[95] Pfeifenberger Direct Testimony, 2012, pp. 77-78.

[96] MISO, 2011, pp. 42-44.

previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).[97] The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in $/MWh). Estimates of the average VOLL can exceed $5,000 to $10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.[98]

When a transmission investment reduces the loss of load probabilities, system operators may be able to reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.[99]

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation capital investment needs ranging from $1.0 billion to $5.1 billion in present value terms,

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97 SPP, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

98 ATC, 2009.

99 This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

accounting for 10–30% of total MVP project costs.[100] This benefit was similarly recognized by the SPP Metrics Task Force,[101] as well as by the Public Service Commission of Wisconsin, which noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.[102]

C. GENERATION INVESTMENT COST SAVINGS

Transmission investments can also reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three societal benefits.

1. Generation Investment Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.[103]

[100] MISO, 2011, pp. 34-36.

[101] SPP, 2012, Section 5.1.

[102] PSC WI, 2008, p. 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

[103] Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP's evaluation of its Priority Projects showed $71 million in capacity savings from reduced losses, or 3% of total project costs.[104]
- ATC found that its Paddock-Rockdale project provided an estimated $15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.[105]
- MISO also found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of $111 to $396 million, offsetting 1–2% of project costs.[106]
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately $50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.[107]

2. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy's service area showed that the transmission projects provide increased import capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy's resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at $320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.[108] A similar analysis also identified approximately $400 million in resource adequacy benefits from deferred

other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

104 SPP, 2010, p. 26.

105 ATC, 2007, pp. 4 (project cost) and 63 (capacity savings from reduced losses).

106 MISO, 2011, pp. 25 and 27.

107 Pfeifenberger Direct Testimony, 2012a, pp. 58-59.

108 *Id.*, pp. 69.

generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

3. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case (*e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.[109] The capital cost savings were estimated at $12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.[110] The analysis found that sites in Illinois offered

[109] CAISO PVD2 Report, 2005, pp. 25-26.

[110] ATC, 2007, pp. 54-55.

significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin. In that instance, the analysis should have implemented different production cost assumptions in the Base and Change Cases to reflect the access to lower production cost generation with the new line compared to the status quo.

Access to a lower-cost generation option can also significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits" in Subsection F below, the Midwest ISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more transmission investment.[111] This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have also provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

D. Benefits from Increased Competition and Market Liquidity

Transmission projects can provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets.

1. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include mark-ups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market. Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers' market power and reduce overall market concentration. The overall magnitude of benefits from increased competition can range widely, from a small fraction to multiples of the

[111] MISO, 2010, p. 32 and Appendix A.

simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12 month period during which the crisis occurred.[112] More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."[113]

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide $28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.[114] Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.[115] A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[116]

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[112] CAISO TEAM Report, 2004, pp. ES-9.

[113] FERC Performance Metrics, 2011, p. 106.

[114] CAISO PVD2 Report, 2005, pp. 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

[115] CAISO TEAM Report, 2004 (using the proposed Path 26 upgrade as case study).

[116] Pfeifenberger Direct Testimony, 2008; and ATC, 2007, pp. 44-47 and pp. 4 (project cost) and 63 (competitiveness benefit).

2. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets also imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (*e.g.*, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[117] At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a $0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save $4 million to $40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately $500 million annually on a nation-wide basis.

E. ENVIRONMENTAL BENEFITS

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.,* SO_2, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emission generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emission prices such as SO_2 and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO_2 in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emission generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

[117] Pfeifenberger Oral Testimony, 2006, p. 39.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde-Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO_2 emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of $1 million to 10 million per year.[118] Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO_2 emissions from fossil-fuel generators every year.[119] That estimated emission reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

F. PUBLIC-POLICY BENEFITS

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by *one quarter* for the same amount of renewable energy produced compared to the investment costs of wind generation in locations with a 30% capacity factor.[120] Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be $500 to $700 per kW of installed wind capacity.

As noted earlier, the Midwest ISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over $110 billion for either all local or all regional wind resources to $80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over $30 billion.[121] These cost savings could be achieved by increasing the transmission investment per kW of wind generation from $422/kW in the all-local-wind case to $597/kW in the lowest-total-cost case.

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[118] CAISO PVD2 Report, 2005, pp. 26.

[119] Pfeifenberger Direct Testimony, 2012, pp. 83.

[120] For example, see Burns & McDonnell, 2010, pp. 1–2, Figure 2.

[121] MISO, 2010, p. 32 and Appendix A.

A similar analysis was also carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[122] Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.[123]

Additional transmission investment can also help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operations (which includes a variable cost reduction). If less generating capacity from conventional generation is needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only $1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed $25 million.

To summarize, even though making significant transmission investments to gain access to remotely-located renewable resources seems to increase the cost of delivering renewable generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.[124] While this rationale will not apply to every public-policy-driven transmission project, it

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122 MISO, 2011, pp. 25 and 38-41.

123 ATC, 2009, p. 7.

124 In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not be to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

G. Employment and Economic Stimulus Benefits

Transmission investments will also stimulate the local, regional, and national economy, supporting employment and regional economic activities. However, unlike the other economic benefits described above, the direct and indirect employment and economic stimulus associated with the construction and operations of the transmission system are benefits that do not reduce customer's electricity rates or improve their quality of service. These benefits are a measure of the effects of changes in power sector spending on other sectors in the economy, taking into account the input and output relationships among industries, consumers, and governments. For example, the construction of transmission facilities requires the use of labor and materials. Most of the manufacturing and construction activities will directly benefit the local economy by creating construction jobs. While certain input materials, such as towers and concrete, likely are sourced from within the region or from near-by regions, other materials such as cables and other electrical components may be imported from outside of the project's region or even from outside the U.S.

To measure the employment and overall economic activity supported by transmission investments, studies rely on a class of models known as input-output models.[125] Input-output models are universally used by economists and policy analysts to estimate how specified changes in spending affect every sector of a state's or region's economy.[126] Input-output models are

[125] Some of the studies did not utilize full input-output models but relied on the "economic multipliers" taken from these models. Nonetheless, the multipliers are consistent with input-output models and assumptions. Input-output models are based on detailed economic data on how goods and services are produced and consumed. An input-output model rebalances the overall economy after an increase in expenditures on particular types of products (*e.g.*, construction activities and electric transmission equipment) such that the quantity produced equals the quantity consumed for every industry. These models specifically consider how much of the consumed products and services are supplied from each sector of a state or region.

[126] The majority of the studies we surveyed relied on the well-known and widely-used IMPLAN Model of the Minnesota IMPLAN Group (MIG) to estimate the employment and economic stimulus benefits of transmission investments. The IMPLAN (IMpact analysis for PLANning) economic impact modeling system is developed and maintained by MIG, which has continued the original work on the system done at the University of Minnesota in close partnership with the U.S. Forest Service's Land and Management Planning Unit. IMPLAN divides the economy into 440 sectors and allows the user to specify the expenditure allocations associated with a given expansion in demand to all relevant parts of the local economy in order to derive the economic impacts—changes in employment, earnings, and economic output. According to the U.S. Department of Agriculture, currently "over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis." In 2009, the U.S. Army Corps of Engineers Civil Works program utilized IMPLAN employment multipliers "to estimate the potential number of jobs preserved or created" by the American Recovery and Reinvestment Act of 2009. In addition, the U.S. Department of Commerce, the Bureau of Economic Analysis, the U.S. Department of Interior, the Bureau of Land Management, and the Federal Reserve System member banks are also among the agencies that utilize IMPLAN for economic impact analysis.

used to estimate: (1) the number of jobs supported in the region (in full-time-equivalent years or "FTE-years" of employment);[127] and (2) the economic activities generated in the region (*i.e.*, increased "economic output" as measured in total sales and resale revenues of businesses within the study region). Since these models report economic activity as the sum of the value of all goods and services sold at each level of the supply chain (*i.e.*, sales and resale revenues), the reported economic output refers to the total flow of money that occurs throughout the local economy. The measured impacts are the cumulative (undiscounted) number of jobs (or FTE-years of employment or FTE jobs each year), and the overall economic activity (in constant dollars) associated with investing in transmission projects over the entire construction phase.[128]

It is important to note, however, that the employment and economic stimulus impacts associated with the construction and operation of the transmission system are not additive to the economic benefits accruing in the power sector. In addition, increasing or decreasing costs for electric customers or increasing or decreasing profits to the investors of generators will also have downstream employment and economic stimulus effects.

Our 2011 analysis conducted for WIRES shows that every $1 billion of U.S. transmission investment directly and indirectly supports approximately 13,000 full-time-equivalent (FTE) years of employment and $2.4 billion in total economic activity.[129] Approximately one-third of this employment benefit is associated with the direct construction and manufacturing of transmission facilities. Two-thirds of the total impact is associated with indirect and induced employment by suppliers and service providers to the transmission construction and equipment manufacturing sectors. As shown in Table 11, the WIRES report also summarized nine previous

[127] Employment impacts are generally reported as full-time-equivalent (FTE) job years, that is, 2,080 hours of full employment. For example, reporting 100 FTE years of employment could mean 200 full-time jobs supported for 6 months, 100 jobs supported for a year, or 10 jobs supported for 10 years.

[128] The employment and economic stimulus effects are typically quantified under three types of effects: "direct," "indirect," and "induced" impacts. Direct effects represent the changes in employment and economic activity in the industries which directly benefit from the investment (*i.e.*, construction companies, transmission materials and equipment manufacturing, and design services). Indirect effects measure the changes in the supply chain and inter-industry purchases generated from the transmission construction and manufacturing activities (*e.g.*, suppliers to transmission equipment manufacturers). Induced effects reflect the increased spending on food, clothing, and other services by those who are directly or indirectly employed in the construction of the transmission lines and substations. Employment supporting the three activities represents discrete net gains to the overall economy if the labor force is not being utilized elsewhere in the economy absent the projects. If the employment in a certain region is tight such that creating new jobs only allows people to change from less to more desirable jobs, very few new jobs would be created.

[129] Pfeifenberger and Hou, 2011.

studies of the employment and economic stimulus benefits of transmission investments, covering a wide range of regions in the U.S. as well as portions of Canada.[130]

The summary shows that the local, state-level employment impacts range from a low of 2 FTE-years of total employment supported per million dollars of investment to a high of 18 FTE-years per million of investment (shown in Table 11 column [E]), with a majority of studies showing that each million dollars of transmission investment supports between 5 and 8 FTE-years of local employment. The economic output per million dollars of total transmission capital cost ranges from a low of $0.2 million to $2.9 million (shown in Table 11, column [F]).

In addition to employment and economic output, some studies also have estimated the increase in personal income earned by employees, local tax revenues, lease payments to local landowners, and stimulus to individual industries. While not all of the studies estimate these additional employment and economic stimulus benefits (and they cannot simply be added to other project benefits for the purpose of benefit-cost analyses as discussed in Section IV.B of this report), they nevertheless represent actual flows of wealth throughout a defined regional economy.

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130 There are several other studies discussing transmission-investment-related benefits to the regional or national economies, which are not included on our summary due to insufficient detail contained in or the different nature of these studies. For example, see Build Energy America!, 2011; McBride, *et al.*, 2008.

More recent studies not summarized in the following discussion include: Perryman, 2010; Lewis and Pfister, 2010; and Lowe *et al.*, 2011.

Table 11
Employment and Economic Impacts of Transmission Investments per Million Dollars of Total and Local Spending

	Study Sponsor	Project Summary	% Local Spending	Based on Total Transmission Capital Cost: FTE-Years of Employment Per $ Million		Based on Total Transmission Capital Cost: Total Economic Output Per $ Million	Based on Local Spending: FTE-Years of Employment Per $ Million		Based on Local Spending: Total Economic Output Per $ Million
				Direct	Total	($ Million)	Direct	Total	($ Million)
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
[1]	AltaLink	AltaLink's estimated capital spending							
		Alberta	75%	5	7	N/A	7	9	N/A
		Rest of Canada Outside of Alberta	75%	N/A	3	N/A	N/A	3	N/A
[2]	ATC LLC	Two completed projects							
		1. 138 kV Femrite-Sprecher	46%	N/A	5	$0.7	N/A	11	$1.5
		2. 345 kV Arrowhead-Weston	100%	N/A	8	$1.4	N/A	8	$1.4
[3]	CapX2020	Five major transmission projects	100%	7	13	$1.9	7	13	$1.9
[4]	Central Maine Power	Maine Power Reliability	81%	4	6	N/A	5	7	N/A
[5]	Montana Department of Labor & Industry	Six major projects planned or under construction in Montana							
		1. Out-of-state contractors	11%	1	2	$0.2	11	17	$1.7
		2. In-state contractors	33%	2	5	$0.6	7	14	$1.7
		3. In- and out-of-state contractors	17%	2	3	$0.3	9	16	$1.7
[6]	Perryman Group	CREZ transmission	100%	N/A	18	$2.9	N/A	18	$2.9
[7]	South Dakota Wind Energy Association	Eastern South Dakota 345 kV transmission	25%	1	3	$0.3	8	11	$1.3
[8]	SPP	Various Priority Projects							
		1. Group 1 - low in-region	47%	4	7	$0.9	8	14	$1.8
		2. Group 1 - high in-region	74%	5	8	$1.3	6	11	$1.7
		3. Group 2 - low in-region	47%	4	7	$0.8	8	14	$1.8
		4. Group 2 - high in-region	73%	5	8	$1.2	6	11	$1.7
[9]	Wyoming Infrastructure Authority	Combination of 500 kV HVDC, 500 kV HVDC, and 230 kV HVAC	33%	5	5	$0.4	14	15	$1.3

Sources and Notes:

For full source citations, please refer to Table 3 in Pfeifenberger and Hou, 2011.

[1]: "Rest of Canada Outside of Alberta" impacts reflect AltaLink's capital spending on other provinces. The study provided a value-added impact which is not reflected in the table above.

[3]: Direct output assumed to be local spending.

[4]: The study provided a value-added impact which is not reflected in the table above.

[5]: Direct output assumed to be local spending.

[6]: The study provided a value-added impact which is not reflected in the table above.

[9]: NREL "direct" employment data have been adjusted by adding "indirect" impacts to align with other IMPLAN study definitions.

H. Other Potential Project-Specific Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

1. Storm Hardening

In regions that experience storm-induced transmission outages, certain transmission upgrades can improve the storm resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where VOLL can be significantly large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.[131]

2. Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[132]

3. Synergies with Future Transmission Projects

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that

[131] Pfeifenberger Direct Testimony, 2012, pp. 79–80.

[132] For example, see *ibid.*, p. 80.

region.[133] Planning a set of "no-regrets" projects that will be needed under a wide range of future market conditions can help capitalize on such "option value." For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a "no regrets" step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states' RPS requirements over the next 10 to 20 years.[134] A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project's standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout.

4. Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way "corridors" on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, "upsizing" a transmission line ahead of actual need (*e.g.*, to a double-circuit or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (*e.g.*, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to "up-size" lines in the future may be valuable even without right-of-way limits, this option will be particularly valuable if finding additional rights-of-way would be very difficult or expensive.

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[133] CAISO TEAM Report, 2004, pp. 9–21. Tehachapi region referred to as Kern County.

[134] Pfeifenberger and Newell Direct Testimony, 2011.

5. Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

6. Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.[135]

7. Increased Wheeling Revenues

A transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately $400 million of potential resource adequacy benefits were realized from deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately $130 million of the $400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.[136]

[135] Budhraja *et al.*, 2008, pp. 43-44.

[136] For example, see Pfeifenberger Direct Testimony, 2012, pp. 73-76.

8. Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs and Day-2 markets such as ERCOT, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs (though not societal costs) by allowing imports from lower-cost portions of the region.[137] While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.[138]

9. Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current ("HVDC") transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;[139] (2) supply voltage and frequency support;[140] (3) improve transient stability[141] and reactive performance;[142] (4) provide AC system damping;[143] (5) serve as a "firewall" to limit the spread of system disturbances;[144] (6) "decouple"

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137 As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

138 Pfeifenberger Direct Testimony, 2008, Appendix A; and ATC, 2007, p. 63 (FTR and congestion).

139 Bahrman (2008), p. 5.

140 Wang, *et al.*, 2008, p. 19.

141 IEEE PES, 2005, p. 75.

142 As noted in several sources including: (1) UMD CIER, 2010, p. 51; (2) EWEA, 2009, p. 27; (3) Siemens, n.d.; and (4) Wright *et al.*, 2002, p. 5.

143 IEEE PES, 2005, p. 75.

144 Siemens, n.d.

the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;[145] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of the network.[146] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[147] It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.[148]

145 Lazaridis, 2005, p. 34.

146 As noted in several sources including: (1) EWEA, 2009, p. 27; (2) Siemens, n.d.; (3) Lazaridis, 2005, p. 34; and (4) Wright *et al.*, 2002.

147 PJM 2008 RTEP Update, pp. 8-10.

148 Pfeifenberger and Newell Direct Testimony, 2010.

APPENDIX C – OVERALL SOCIETAL BENEFITS DISTINGUISHED FROM BENEFITS TO ELECTRICITY CUSTOMERS

Society as a whole benefits from transmission investments. As a result, we believe it is most relevant to examine the benefits associated with transmission investments from an economy-wide or societal perspective—as opposed to solely from a customer or generator perspective—when making public-policy or regulatory decisions. The Public Utility Commission of Texas (PUCT) requires that transmission projects be evaluated from a societal perspective, explicitly rejecting the use of a consumer impact or generator revenue reduction perspective for the evaluation of economic transmission projects in ERCOT.[149] Nevertheless, some other regions and regulators, utilities, and customer groups tend to focus on how electricity customers (*i.e.*, "ratepayers") might benefit from the proposed transmission facilities.[150] Recognizing the differences in societal and customer perspectives, we thus briefly summarize key aspects of the two perspectives in this appendix.

This electricity-customer perspective is most relevant when one evaluates how much those who pay for the transmission projects would benefit from them. For instance, electricity customers are likely to benefit from production cost savings (through reduced electricity bills from cost-of-service regulated utilities), from improved reliability (which increases the value of the received service), from an increase in wholesale power market competition (even if that reduces generator profits), from reduced resource adequacy requirements or a reduction in the capacity cost of new generating resources (which reduces electricity bills), and from the avoidance or deferral of transmission or generation investments that would need to be built in the absence of the proposed transmission investment (which provides an offset to the larger transmission projects' costs).

Increased system reliability, reduced emissions, or regional economic development will benefit society as a whole, which includes electricity customers. But these benefits may not directly reduce electricity customer bills. Because benefits to electricity customers can be either a subset of total economy-wide benefits (*e.g.*, because there are benefits that do not directly accrue to electricity customers) or exceed economy-wide benefits (*e.g.*, because generators may see

[149] See PUCT Order 2012. The PUCT Order refers to societal benefits as "levelized annual savings in system production costs resulting from the project," consistent with the current scope of ERCOT's economic benefit metrics (*id.*, pp. 15 and 18). However, the PUCT also concluded that "indirect benefits and cost" associated with a project, as discussed in ERCOT Nodal Protocols, Section 3.11.2(5), should be considered as well (*id.*, p. 32).

[150] Note that the academic literature generally discusses this subject matter by distinguishing between "societal benefits" (or total "welfare gains"), "consumer benefits" (or changes in "consumer surplus"), and "supplier benefits" (or changes in "supplier surplus"). We discuss these concepts in terms of overall economic (or economy-wide) benefits and electricity-customer benefits. See also Baldick, *et al.*, 2007, pp. 17-21.

reduced earnings or other electric customers may see increased rates), the benefit-to-cost balance from an economy-wide perspective may differ from that of electricity customers. For example, a transmission project may offer only limited system-wide production cost savings but offer significant electricity customer benefits by reducing market prices. Alternatively, a significant portion of system-wide production cost savings may be captured by merchant generators through increased earnings, resulting in electricity customer benefits that are less than the identified production cost savings.

The existence and extent of the divergence between customer and societal perspectives can depend on three factors: market structure, geographic scope of the study, and consideration of economy-wide benefits not reflected in electricity rates.

Market Structure. Generally speaking, the cost of power delivered to electricity customers can decrease if a transmission line allows for the dispatch of lower-cost generation or the purchase of wholesale power at lower prices. However, the extent to which electricity customers will benefit also depends on the structure of retail power markets. Under the traditional cost-of-service regulated model, electricity customers will directly benefit from: (1) reductions in the production costs of cost-of-service regulated generating plants; (2) lower-cost off-system purchases by the regulated utility; and (3) the achievement of higher off-system-sales prices for power from such regulated generating plants to offset the revenue requirement to be recovered from franchised ratepayers. In contrast, if electricity customers are served mostly through wholesale power purchases at market prices, such as in retail-access states, customers will benefit if a transmission project reduces the wholesale price of purchased power, irrespective of actual production cost savings. Reducing the cost of power to electricity customers is not automatically an economy-wide benefit because, when customers pay less for their power, a portion of those savings may be a transfer of economic gains from generators to those customers. This transfer of gains can yield a result in which the economy-wide benefit is less than the electricity-customer benefit. In other words, when customers pay less, generators may earn less, leaving the economy-wide benefit to be less than the direct benefits electricity customers may enjoy.

Geographic Scope of the Study. Transmission investments can affect a wide range of market participants in regions adjacent to where a project is located. When estimating the overall benefits of this type of transmission project, the impacts on consumers and generators in neighboring regions need to be considered as well. In some situations, the overall benefits of a transmission project may exceed the benefits realized in a particular region because additional benefits may accrue to electricity customers and generators in neighboring regions. It is also possible that the benefits to electricity customers in the region where the project is located exceed the overall economy-wide benefit if the transmission project increases electricity customers' costs in the neighboring regions. For example, a new transmission line that allows for local electricity customers to purchase power at lower prices from a neighboring market may cause wholesale prices to increase in that neighboring market, possibly benefitting generators but increasing electricity customers' costs in the neighboring market.[151]

Economy-wide Benefits Not Reflected in Electricity Rates. The benefits of transmission investments may also extend beyond the direct benefits to electricity market participants. This is the case when some of the economy-wide benefits of transmission investments accrue to society more broadly—external to the scope of electricity costs, generator profits, or system reliability. For example, a reduction of greenhouse gas emissions due to a shift in generation resources towards more renewable energy resources resulting from a transmission upgrade can provide a societal benefit. Without a market that places an explicit monetary cost on the emissions, the societal benefit associated with reduced emissions would not materialize in reduced costs to electricity customers. Only if a price was placed on greenhouse gas emissions (as is the case for SO_2 and NO_x emissions) will the benefits associated with emissions reduction accrue to electricity customers through reduced costs. However, even though these emissions are not priced today, it is important to value on a probabilistic basis—including from a risk mitigation perspective—the likelihood that they will be priced in the future. Economy-wide benefits can also include the employment and economic development benefits of expanding the existing transmission infrastructure,[152] including benefits from stimulating the local economy, producing additional tax revenues, supporting industrial growth, or allowing the development of renewable power projects that, in turn, provide many similar economic stimulus benefits. However, the jobs and economic stimulus associated with constructing and maintaining the transmission system would only provide incremental benefits to a region if alternative investment activities could not offer similar benefits.[153] Thus, while it is useful to estimate the potential employment and economic stimulus benefits associated with certain transmission investments, they cannot simply be added to other project benefits for the purpose of benefit-cost analyses.

Overall, we recommend using a societal or economy-wide perspective (with a sufficiently wide geographic scope) when evaluating the benefits and costs of transmission projects. However, due to regulatory requirements or for cost allocation purposes, it may also be necessary to conduct the analysis from an electricity customer perspective. In either case, it is important to deliberately specify how market structure and the geographic scope of the study will affect the

[151] For a simplified illustration and discussion of how economy-wide benefits compare to electricity customer and generator benefits in two regions interconnected by a transmission upgrade, see also Hogan, 2011.

[152] However, it is important to ensure that the partial macroeconomic impacts associated with changes in spending in the power sector is not directly added to the spending effects already accounted for in the other benefit categories.

[153] For example, if workers are fully employed in an economy, building more transmission may not offer additional employment benefits to the region, and job creation alone does not necessarily or automatically ensure that certain investments provide a productive use of the associated investment capital. Further, the employment-related benefits from constructing transmission facilities would need to be weighed against the economic implications of potential increases in electricity rates.

investments' benefits and costs. Evaluating impacts from an electricity customer perspective should also consider benefits (such as increased reliability) that are not reflected in electricity rates.

APPENDIX D - STAKEHOLDER PARTICIPATION LIST

Stakeholders interviewed during the initial study effort:

Organization:	**AEP**
Date:	April 26, 2013
Attendees:	Jennifer L. Bevill and others
Organization:	**Austin Energy**
Date:	April 30, 2013
Attendees:	Biju Matthew, Reza Ebrahimiaan
Organization:	**Edison Mission**
Date:	April 22, 2013
Attendees:	Marguerite Wagner
Organization:	**Lone Star Transmission**
Date:	March 25, 2013
Attendees:	Matthew Gomes and others
Organization:	**Lower Colorado River Authority (LCRA)**
Date:	April 17, 2013
Written comments:	Sergio Garza
Organization:	**Luminant**
Date:	March 26, 2013
Attendees:	Shannon Caraway, Vicki Oswalt, Amanda Frazier, Ed Svihla
Organization:	**Oncor**
Date:	March 26, 2013
Attendees:	Mike Juricek, Liz Jones, April Pinkston
Organization:	**Potomac Economics**
Date:	April 3, 2013
Attendees:	Dan Jones
Organization:	**Save Our Scenic Hill Country Environment (SOSCHE)**
Date:	March 25, 2013
Attendees:	Robert Weatherford, Tim Lehmberg, Roger Studer
Organization:	**Stratus Energy**
Date:	March 25, 2013
Attendees:	John Moore
Organization:	**Texas Landowners Representatives**, including Tri-Community Alliance, F-to-Z Coalition, Energy Edge Consulting
Date:	May 2, 2013
Attendees:	Brad Baliff and representatives of each organization
Organization:	**Texas Industrial Energy Customers**
Date:	March 25, 2013
Attendees:	Katie Coleman, Charles Trissey

Stakeholders who submitted comments on draft recommendations:

Organization: **Luminant**
Date: June 28, 2013
Name: Amanda J. Frazier

Organization: **Oncor**
Date: June 28, 2013
Name: April C. Pinkston

Organization: **South Texas Electric Cooperative**
Date: June 25, 2013
Name: John Moore

Organization: **Texas Industrial Energy Customers**
Date: June 24, 2013
Name: Katie Coleman

Organization: **Lone Star Transmission**
Date: June 24, 2013
Name: Randa Stephenson

Organization: **Electric Power Engineers, Inc.**
Date: June 28, 2013
Name: Hala N. Ballouz

Organization: **Lower Colorado River Authority (LCRA)**
Date: June 21, 2013
Name: Segio Garza

Organization: **AEP**
Date: June 18, 2013
Name: Jennifer L. Bevill

Organization: **Public Utility Commission of Texas**
Date: June 18, 2013
Name: Mike Lee

Organization: **ERCOT**
Date: June 17, 2013
Name: John Adams

Organization: **Save Our Scenic Hill Country Environment (SOSCHE)**
Date: June 6, 2013
Name: Robert Weatherford

APPENDIX E – JUNE 3, 2013 RPG PRESENTATION: "DRAFT RECOMMENDATIONS FOR ENHANCING ERCOT'S LONG-TERM TRANSMISSION PLANNING PROCESS"

The Brattle Group

Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process

Presented to:
ERCOT Regional Planning Group

Presented by:
Johannes Pfeifenberger
Judy Chang

June 3, 2013

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Session 5: Societal Benefits Metrics

Appendix: Details on Societal Benefit Metrics

2 The Brattle Group

Background on Long-Term Planning Process

DOE Grant is used to enhance ERCOT long-term planning:

- Augment and enhance the existing long-term planning efforts for the ERCOT region
- Increase the technical knowledge and capabilities of ERCOT staff
- Expand the long-term planning horizon to 20-years
- Support expansion of the existing ERCOT planning stakeholder process

Specifically, the intent of this effort is to:

- Provide relevant and timely information on the long-term system needs to inform nearer-term planning and policy decisions
- Expand ERCOT long-term planning capabilities by developing new tools and processes, including:
  - Extending the planning horizon
  - Incorporating the operational reliability and detailed analysis of the economic viability of emerging technologies
- Facilitate enhanced stakeholder involvement and input into the long-term planning process that seeks for stakeholder consensus.

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Resulting Long-Term Study (LTS)

ERCOT's effort of enhancing its long-term planning process involves:

- Assessment of transmission needs under various future scenarios
  - Scenarios (over 20-year horizon) were developed through a stakeholder-based "Scenario Development Working Group"
  - Supplement existing 10-year long-term system assessment (LTSA)
- Analyses of proposed economic transmission projects
  - Modeling impact of on production costs and system reliability
  - Compare benefits to costs of economic transmission projects
- "Indicative" results about beneficial transmission projects

The long-term-planning effort is intended to:

- Supplement RTP process to help improve understanding of economic value, identify additional economic projects, increase robustness and benefits of transmission options in long-term
- Indicate system needs that require longer implementation time frame than 5-6 years (if any)

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Objectives of Brattle Engagement

Review long-term planning process and develop recommendations to improve business case for transmission from societal perspective:

- Provide careful review and suggest improvements to the long-term transmission planning process
- Provide ERCOT options for expanding its planning processes to include more comprehensive assessments of transmission benefits and costs
  - Develop and demonstrate metrics and methodologies for valuing additional (non-conventional) transmission-related societal benefits
- Assist ERCOT in improving its modeling of the impact of transmission projects
  - Identify the strengths and weaknesses of existing models and tools
  - Suggest improvements in modeling applications and procedures
- Conduct workshops for ERCOT staff, to educate stakeholder, and present results and recommendations

Our Approach to this Effort

1. Reviewed documentation on ERCOT RTP (near-term) and long-term (LTSA and LTS) planning processes
2. Interviewed stakeholders and ERCOT staff to:
   - Better understand overall study approach
   - Collect stakeholders' views on existing process and potential improvements
   - Understand modeling practices and flow of data and information among ERCOT internal teams
3. Reviewed long-term planning process to evaluate its effectiveness
4. Reviewed and evaluated ERCOT's current modeling approach
5. Proposing additional transmission benefits metrics that can be incorporated in evaluating the merits of potential projects
6. Conducting discussions on how to improve specific benefit-cost evaluation approaches (based on industry's best practices)
7. Brattle report due in early July (appendix to ERCOT's DOE report)

Areas of Long-Term Planning Addressed

	Assess and Improve the Process for the Existing Planning Scope	Broaden the Scope to More Effectively Identify Projects with Net Benefits
1. Study Plan (objectives and high-level concepts)	- Identify limitations of scope of benefits quantified and project evaluation criteria	- Add benefit categories and metrics - Describe how study scope could be improved - Suggest enhancements to project evaluation criteria

2. Process Steps	- Identify opportunities for improving and streamlining the process
	- Will be informed by an assessment of effort and value, and comparison to processes we've done/seen
	- Clarify process/stakeholder input for identifying promising projects and their likely benefit categories
		- Identify aspects that can be readily added to existing modeling system
		- How to evaluate benefits that can not be captured in existing modeling system
		- For additions that may be a more major effort:
		  - Develop potential process modifications
		  - Identify ways to streamline (e.g., apply selectively or to a portfolio; develop generic benefit multipliers)

3. Modeling Tools, Execution, and Quality Control Practices	- Identify specific improvement opportunities for:
	  - model calibration
	  - quality control (diagnostics and review)
	  - data and case management
	  - automation of repeated processes
	  - documentation of modeling steps
	  - staff training
		- What are best practices and training needs for successfully executing new steps/tools?

4. What to do with the Results		- Identify ways to integrate LT planning better with actionable near-term planning (e.g., by merging models and including LT NPV in near-term study)

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Summary of Stakeholder Comments

We interviewed a wide range of stakeholders:

- Transmission service providers, land owners, generators, municipal utilities, consultants, and the Market Monitor

Main themes of feedback targeted on:

- Appreciative of ERCOT's effort; significant value in conducting long-term planning; hopeful that this effort will enhance planning over time
- Questions about scenarios
  - Not fully clear how they came about
  - Future uncertainties covered by the scenarios too wide or too narrow
- Need more clarity around how the results of long-term planning efforts will being used
- Unclear about extent to which stakeholder input can be provided or can make a difference

Stakeholder Comments: Agreed-Upon Next Steps

Generally agreed-upon areas for further improvement:

- Next phase needs to sharpen the goal definition of Long-Term Planning and needs to establish how results generated through Long-Term Planning will influence "actionable" Regional Transmission Plans
- This first iteration of the effort has been a helpful learning experience; For actual planning going forward, results are only trusted if assumptions and scenarios are considered to be reasonable:
  - Scenarios/assumptions need to be refined; require more widespread buy-in
  - Need to increase level of stakeholder engagement and comfort
- ERCOT expertise and modeling capability valuable; should be supplemented with more stakeholder input and expertise:
  - Local system knowledge should considered more actively when developing project ideas
  - Bottom-up load forecasting can add value to ERCOT long-term projections

Stakeholder Comments: Differences of Opinions

Areas where stakeholders have difference of opinions:

- Desired level of stakeholder involvement
  - Some believe that ERCOT has done a good job facilitating stakeholder input and developing scenarios
  - Others felt excluded either by an inability to participate, difficulties to comprehend, or providing input that they thought was not considered
  - Some intentionally did not participate (more) actively because they felt Long-Term Planning results are not useful or are not going to be used to plan actual transmission projects
- Types of transmission benefits considered
  - Some support ERCOT's effort to capture more economic benefits; they believe many benefits have not yet been considered but should be
  - Others believe that adding benefits will increase unnecessary transmission build-out and are concerned about adding benefits without considering additional costs

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Stakeholder Comments: Differences of Opinions

Areas with difference of opinions (cont'd):

- Range of future scenarios
  - Some believe the range of scenarios are too narrow (too similar), recommending that a wider range of futures that would significantly challenge the system be considered
  - Unclear if assumptions are internally consistent within the scenarios (e.g., renewable energy costs in some of the scenarios)
- Disagreement over the value of long-term planning
  - Some question the value of scenarios and uncertain 10-20 year outlook when transmission can be built quickly in Texas to address challenges when they arise
  - Others are very positive and appreciative about ERCOT taking this step and developing a long-term, scenario-based planning process

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Stakeholder Comments: Our Recommendations

We believe ERCOT has an opportunity to increase stakeholder participation:

- Refine the long-term planning process to ensure that "results matter" and stakeholders understand how
  - Explain how long-term-planning results will be used in RTP process
- Reiterate invitation to all potentially interested parties to participate
- Conduct workshop on scenario development that involves
  - Experts outside of ERCOT and power industry to share views of the future
  - Stakeholder representatives from each sector
  - Document collective results from scenarios developed
- Ensure that scenarios are well documented, shared with all stakeholders, and understood
- Clarify types of transmission benefits and costs considered
  - Conduct special workshop to explain the details of all benefits metrics
  - Explain in detail how benefits will be compared to costs

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Modeling Practices: Assessment

What's working well:

- Modeling process is well designed and documented
- Team Members have high degree of expertise
- Modeling techniques are best-in-class with respect to siting generic generation and making reliability upgrades and transmission constraints internally consistent within each case
- Documentation of process steps and results

Areas for improvement:

- Organizational and modeling team structure
- Model calibration, validation of results
- Simulation of scenarios

Modeling Practices: Recommendations

Integrate organizational and modeling team structure

- Use a single economic model for mid-term and long-term
- Consolidate teams (this is already in process)
- Benefits: this will improve quality/consistency and workflow efficiency; it will also enable the integrated, multi-year planning process we recommend (see next section)

Calibrate models and validate results more systematically

- Backcasting (e.g., price levels and variance, scarcity conditions)
- Develop standardized diagnostics tools

Enhance scenario and uncertainty modeling

- Improve simulations to capture actual levels of congestion and production costs more accurately across all scenarios
- Develop simulation of uncertainties within scenarios (e.g., weather or outage-related stress conditions)

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Current Planning Process: Areas for Improvement

We identified room for improvement in the current long-term transmission planning process:

- Current implementation of economic project process will miss beneficial projects by considering only the first year of a project:
  - First year production cost savings generally lower than their levelized value because benefits tend to grow over time
  - Note: first-year project costs (estimated at 1/6 of construction costs) are higher than their levelized value because project costs decline over time as the assets are depreciated
- Current economic project process and tools understate production cost savings and do not capture a range of other potential benefits and costs
- Disconnect in near-term/long-term planning processes can result in missed opportunities to identify beneficial economic projects that avoid or defer reliability projects
  - Once a reliability project is built, an economic project generally will not be as valuable than otherwise due to missed benefits from earlier years and the missed opportunity to avoid the reliability project costs

Economic Planning Process: Recommendations

Recommended improvements to the long-term economic transmission planning process for further consideration:

1. Stitch together the RTP and Long-Term economic evaluation scope, so that Long-Term Planning results can be used in the RTP
2. Use Long-Term Planning results in evaluating economic projects in RTP (and the possibility of avoiding/deferring reliability projects)
   - Allows analysis of whether an economic project identified in Long-Term-Planning effort should be accelerated for consideration in RTP:
     - For example, advance a possible economic project from year 10 to avoid reliability upgrade in year 5 (and likely additional reliability upgrades in years 10 and 15)
   - Use Long-Term Planning to assess value of economic project alternatives to reliability upgrades identified within RTP process
   - Projects would still be approved through RTP for in-service dates within RTP timeframe, but their value would be informed by long-term assessment
3. Expand benefits and costs considered and develop metrics to quantify their monetary value

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Economic Planning Process: Recommendations

4. Implement NPV-based/levelized benefit-cost comparison
   - Levelized value of societal benefits tends to far exceed their first-year value
   - Note: first-year transmission revenue requirement (TRR) (approximately equal to 1/6 of project construction costs) is about 30% higher than the levelized value of TRRs over the project life, creating a B-C threshold of 1.3
5. Improve the use of scenarios and sensitivities in the planning process
   - Use long-term scenarios (e.g., of alternative outlooks for fuel prices, load growth, generation mix, locations, etc.) to test the robustness of economic projects, including those considered in the RTP
   - Consider uncertainties (e.g., weather, contingencies, fuel costs) through simulation of sensitivities within each scenario (i.e., for same normalized load and generation mix) to capture full expected value of benefits
6. Enhance economic project and benefits/costs identification process:
   - Formalize process for market participants to propose economic projects and specify all benefits and costs (see “checklist” of possible benefits)
   - Obtain broad stakeholder input on the proposed transmission projects and their identified societal benefits and costs to help prioritize

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Need for Linking Near- and Long-Term Planning

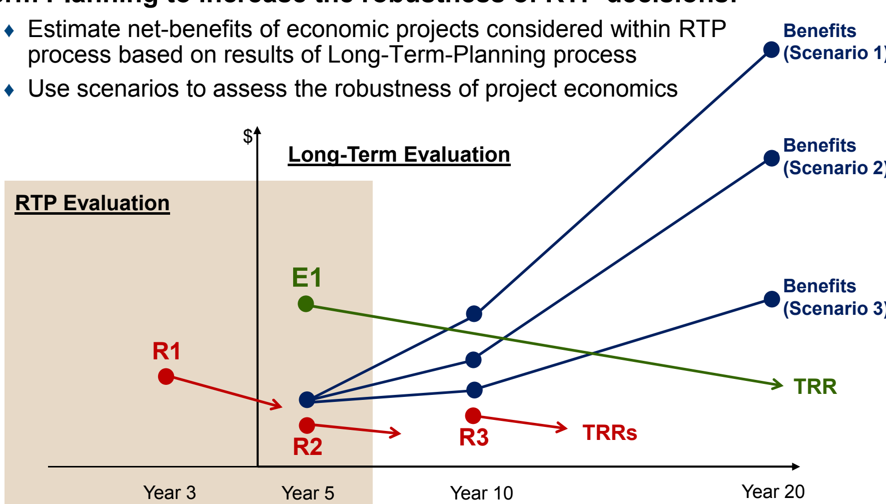
Differences in analytical approaches used to identify reliability and economic transmission projects require integration of near- and long-term planning processes.

- Reliability need is determined for a **single point in time** (e.g., 2017)
- The societal economic value of a transmission project for that *same point in time* (e.g., 2017) is dependent on the **present value** of its annual costs and benefits, looking forward over the entire life of the asset (e.g., 2017-57)
- Present values of actual annual costs and benefits can easily be expressed as **"levelized" annual values** that yield exactly the same present value.

Use Long-Term Planning to Supplement RTP

We recommend that ERCOT use "look ahead" from Long-Term Planning to increase the robustness of RTP decisions:

- Estimate net-benefits of economic projects considered within RTP process based on results of Long-Term-Planning process
- Use scenarios to assess the robustness of project economics



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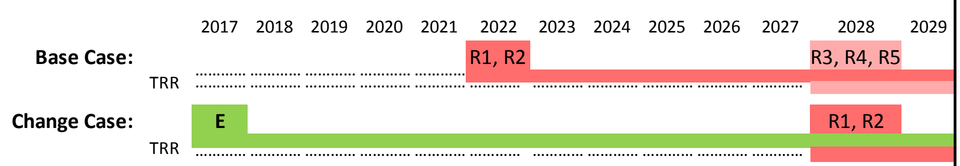
Example: Long-Term Benefits of Economic Project

Realistic example of an Economic Project built in 2017

- Defers: $90 million reliability projects (R1, R2) from 2022 to 2028
- Avoids: $321 million reliability projects (R1, R2, R3) in 2028



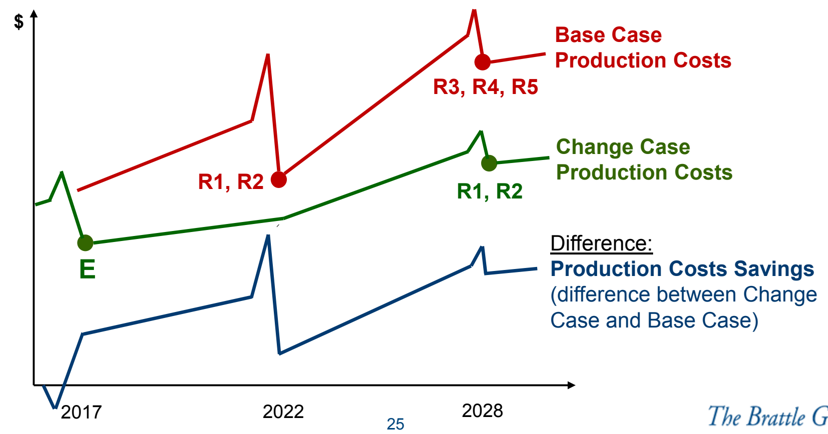
Benefits estimation involves the following steps:

- Estimate costs and benefits in Base Case (for selected years), represented by the combination of R1,2 and R3, R4, R5
- Estimate costs and benefits the Economic Project for same years
- Difference between the two streams of costs and benefits = *Incremental benefits associated with the Economic Project*

Example: Production Cost Savings (Concept)

Economic project ("E" in Change Case) offers benefits relative to reliability solution ("R1, R2" and "R3, R4, R5" in Base Case):

- Production cost savings (as illustrated below)
- Deferred (R1, R2) and avoided (R3, R4, R5) reliability project costs



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Example: Production Cost Savings (Results)

Results from ERCOT production cost simulations:

- Production costs savings estimated for 2017, 2022, and 2028 as difference between Base Case and Change Case, showing:

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case	$15,233	$15,881	$16,528	$17,176	$17,823	$18,468	$19,084	$19,700	$20,316	$20,932	$21,549	$22,128
Change Case	$15,228	$15,870	$16,511	$17,153	$17,794	$18,436	$19,037	$19,637	$20,238	$20,839	$21,440	$22,038
Savings:	$5	$11	$17	$23	$29	$32	$48	$63	$78	$93	$109	$90

  - $5 million in 2017 $32 million in 2022 $90 million in 2028
- Interpolated production cost savings between 2017, 2022, and 2028
  - Used 2022 and 2028 cases without reliability upgrades to estimate 2021 and 2027 savings for interpolation purposes
  - Held 2028 savings constant in real terms (i.e., grown with inflation)
- Estimated benefit of deferring/avoiding reliability projects
  - Difference in reliability-project TRRs for Base Case and Change Case

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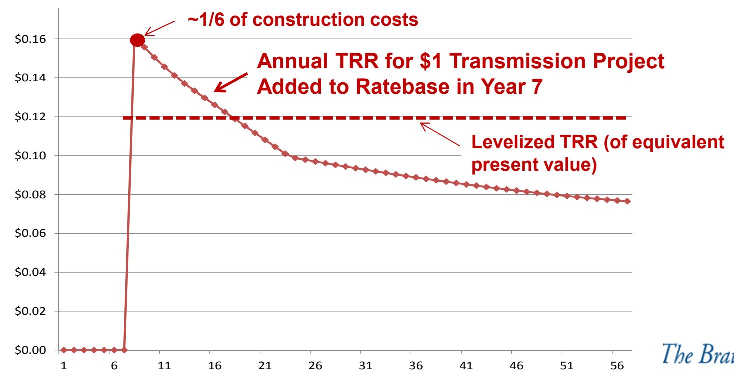
Transmission Revenue Requirements (TRR)

Under "cost-of-service" regulation, the annual cost of transmission is calculated as an asset's TRR:

TRR = Depreciation + Return on Ratebase + Taxes + O&M Costs

- TRRs decline as the project's Ratebase is depreciated over time
- Accelerated tax depreciation makes TRRs decline faster over initial 15 years



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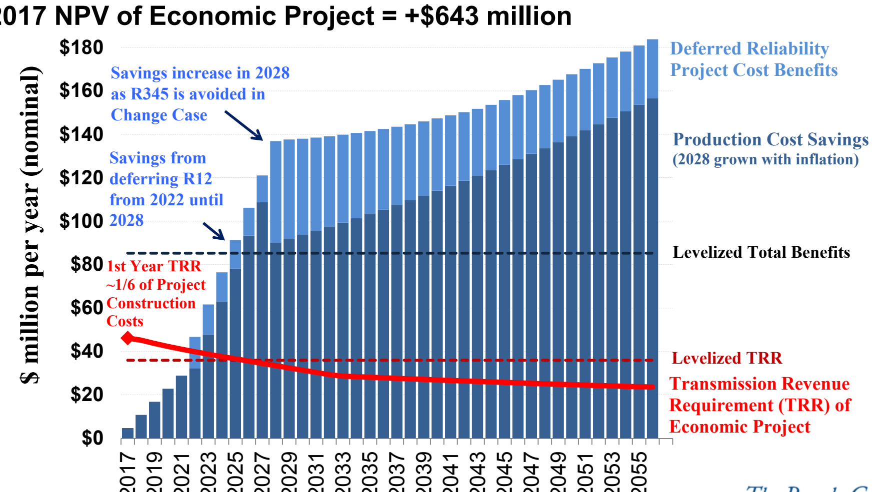
Example: 40-year NPV of Economic Project

2017 PV of Economic Project TRRs = $465 million

2017 PV of Benefits = $866 million + $241 million = $1,107 million

2017 NPV of Economic Project = +$643 million



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Example: Take Aways

Example shows that project would be rejected based on current benefit-cost approach:

- First-year production cost savings ($5 million) compares poorly to 1/6 of construction costs ($49 million)

Long-term perspective shows that the 2017 value of production cost savings and avoided reliability project costs far exceed the economic project's costs:

- $1.1 billion PV of project benefits vs. $465 million PV of project TRRs
- $85 million of levelized annual benefits vs. $36 million in levelized TRRs and $49 million when measured against 1/6 of construction costs
- Other benefits (or costs) still need to be considered

Example: Take Aways

Results also show that, in this case, the value of the economic project might be increased by delaying it until the R1+R2 reliability upgrade would be needed otherwise (e.g., in 2022):

- Economic project is not needed for reliability in 2017
- Production-cost savings suggests that the economic project is not providing net benefits until 2022 or after (but other benefits may change that result)

Question remains:

- Whether this (or other) economic project could also cost-effectively defer/avoid other RTP-identified reliability upgrades
- What other tangible societal benefits are provided by the economic project and how can these benefits (or costs) be quantified or otherwise considered (see next Session)

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Societal Benefit Metrics: Assessment

Societal benefits already considered in ERCOT's assessment of economic projects:

- Production cost saving
- Benefits of deferring/avoiding reliability upgrades

This scope does not capture the full societal benefits and costs of new transmission

The current scope is narrower than evolving industry practice, which is considering a broader range of transmission-related benefits

- Examples from other regions (see next two slides)
- Requires careful definition of all societal costs and benefits for cases with and without the contemplated transmission projects
- Some of these benefits can be negative (i.e., reflect costs)

Metrics Used in Other RTOs

SPP ITP analysis:

Quantified
1. production cost savings
2. reduced transmission losses
3. wind revenue impacts
4. natural gas market benefits
5. reliability benefits
6. economic stimulus benefits of transmission and wind generation construction

Not quantified
7. enabling future markets
8. storm hardening
9. improving operating practices/maintenance schedules
10. lowering reliability margins
11. improving dynamic performance and grid stability during extreme events
12. societal economic benefits

(SPP Priority Projects Phase II Final Report, SPP Board Approved April 27, 2010; see also SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP analysis:

Quantified
1. production cost savings
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified
7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO_2 emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM analysis
(PVD2 example)

Quantified
1. production cost savings and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses
7. emissions benefit

Not quantified
8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(CPUC Decision 07-01-040, January 25, 2007 (Opinion Granting a Certificate of Public Convenience and Necessity)

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2012 Effort by SPP's Metrics Task Force

Benefits	Metric	Standard SPP Metric	Recommended New Metric
Adjusted Production Cost Benefits	Adjusted Production Costs	√	
	Energy losses benefits		√
	Mitigation of transmission outage costs		√
Capacity for Losses	Reduced capacity costs	√	
Improvements in Reliability	Avoided or delayed reliability projects	√	
	Capital savings associated with reduced capacity margin		√
	Reduced loss of load probability		√
	Reduced cost of extreme events		√
	Assumed benefits of mandated reliability projects		√
Reduction of Emission Rates and Values	Reduction of emission rates and values	√	
Reduced Operating Reserves Benefits	Lower ancillary services needs and costs	√	
Improvements to Import/Export Limits	Increased wheeling through and out revenues		√
Public Policy Benefits	Meeting policy goals		√

Benefit Metrics Recommendations for ERCOT

We documented industry practice and outlined a broader set of benefits we recommend that ERCOT consider

Organized the additional benefits/metrics into four categories:

- Additional benefits and metrics that should be evaluated routinely
- Those that should be included by developing typical multipliers
- Those for which additional data and tools need to be developed
- Those that should be considered only qualitatively for now

Recommend improved societal benefit/cost identification process:

- Allow market participants propose economic projects, including their likely benefits and costs (based on full "checklist" of possible benefits)
- Obtain broad stakeholder input on the proposed transmission projects and their identified benefits/costs to help prioritize

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Recommendation: Checklist of Economic Benefits

Benefit Category	Transmission Benefit (see Appendix for descriptions and detail)
Standard Production Cost Savings	**Production cost savings as currently estimated by ERCOT staff**
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
2. Reliability and Resource Adequacy Benefits	**a. Avoided/deferred reliability projects (already considered in LTSA)**
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased fuel diversity, reducing the cost of future transmission needs, HVDC operational benefits

Recommendations: 1. Production Cost Savings

Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
1a. Reduced impact of generation outages and A/S unit designations	√				Consider both planned and forced outages in all simulations
1b. Reduced cost of transmission energy losses	√				Estimate based on MLC or full marginal loss simulations
1c. Reduced congestion due to transmission outages		√			Study impact of historical transmission outages
1d. Mitigation of extreme events and system contingencies			√		Develop examples for extreme contingencies and study impacts
1e. Mitigation of weather and load uncertainty		√			Study benefits for 10/90, 50/50, and 90/10 loads
1f. Reduced congestion due to imperfect foresight of real-time conditions				√	Utilize KERMIT zonal simulations as need arises
1g. Reduced cost of cycling power plants	√				Startup costs, increased maintenance costs
1h. Reduced amounts and costs of ancillary services				√	Study conditions under which transmission can provide this benefit (or add to costs)
1i. Mitigation RMR conditions			√		Estimate as RMR need is identified

Recommendations: 2+3. Resource Adequacy and Generation Capacity Cost Savings

Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
2a. Avoided or deferred reliability projects	Improve existing approach				Add analysis of present value of multiple avoided or deferred future upgrades
2b. Reduced loss of load probability **Or:**			√		Utilize results of zonal reliability analyses or use PROMOD reliability simulation option
2c. Reduced planning reserve margin			√		Same as 2b but different realization of savings.
3a. Capacity cost benefits from reduced peak energy losses	√				Estimated based on change in on-peak losses and CONE
3b. Deferred generation capacity investments			√		Further explore potential for ERCOT
3c. Access to lower-cost generation			√		Study locational generation cost differences

Recommendations: 4-7. Market, Environmental, Public Policy, and Economic Stimulus Benefits

Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
4a. Increased competition				√	Study bid mark-ups in load pockets as function of RSI and import capability
4b. Increased market liquidity				√	Study impact of liquidity at trading hubs on transaction costs (bid-ask spreads; hedging costs)
5a. Reduced emissions of air pollutants	√			√	Include emission prices in simulations; consider non-monetized emissions and risk mitigation in long-term scenarios
5b. Improved utilization of transmission corridors			√		Develop approach as project with unique transmission corridor benefit s/costs is encountered
6. Reduced cost of meeting public policy goals				√	Develop quantification approach as public policy requirements or goals are specified
7. Increased employment, economic activity, and tax revenues				√	Provide estimate of employment and economic stimulus benefit per $ million of transmission investment in Texas

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Recommendations: 8. Other Transmission Benefits

Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
8a.Storm hardening				√	Study impact on customer outages and restoration times; compare to alternative costs of achieving same hardening
8b. Increased load serving capability				√	Develop metric as projects with promising increases in future load serving capability are planned
8c.Synergies with future transmission projects			√		Develop framework and most likely applications (e.g., projects that create low-cost future option)
8d. Increased fuel diversity and resource planning flexibility			√		Study generation expansion scenarios to understand value of transmission to mitigate costs of future fuel-mix and locational shifts
8e. Increased wheeling revenues				√	Develop metric as transmission projects that increase imports/exports are considered
8f. Increased transmission rights and congestion-hedging value				√	Develop if deficiencies in congestion hedging options are identified
8g. Operational benefits of HVDC transmission				√	Document and consider operational benefits of HVDC technology as projects are planned

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1. Additional Production Cost Savings

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1a. Reduced impact of generation outages and A/S designations	Consideration of generation outages (and A/S unit designations) will increase impact	Consider both planning and (at least one draw of) forced outages in market simulations. Set aside resources to provide A/S in non-optimized markets.	Outages considered in most RTO's
1b. Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
1c. Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
1d. Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
1e. Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
1f. Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	N/A
1g. Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study

1. Additional Production Cost Savings (cont'd)

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1h. Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
1i. Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)

2+3. Resource Adequacy and Generation Capacity Cost Savings

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
2a. Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
2b. Reduced loss of load probability **<u>Or:</u>**	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
2c. Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3a. Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
3b. Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
3c. Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4+5+6+7. Market, Environmental, Public Policy, and Economic Stimulus Benefits

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits	4a. Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
	4b. Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits	5a. Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
	5b. Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	N/A
6. Public Policy Benefits	Reduced cost of meeting public policy goals	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7. Employment and Economic Stimulus Benefits	Increased employment, economic activity, and tax revenues	Increased full-time equivalent (FTE) years of employment and economic activity related to new transmission line	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

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8. Other Project-Specific Benefits

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
8a.Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
8b. Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
8c.Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
8d. Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
8e. Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
8f. Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
8g. Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

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