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FILING CLERK

Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

RESPONSE TO REQUEST FOR COMMENTS

COME NOW First Solar Inc., Vistra Energy Corp., and the Wind Coalition (collectively, "Commenters"), and submit a copy of *Impacts of Marginal Loss Implementation in ERCOT* by the Brattle Group. Commenters hired the Brattle Group to perform an independent analysis of the potential impacts of implementing a marginal loss methodology for pricing and dispatching generation in ERCOT, as proposed by NRG and Calpine in Project 47199.[1] These comments are focused primarily on putting some of the findings from the Brattle Group analysis of marginal losses into the context of the questions posed by the Commission for comment. Commenters own, operate, or represent members with operations in ERCOT's North, South, and West zones as well as the Coastal, and Panhandle sub-regions. Collectively, peak coincident capacity in these zones amounts to 86% of ERCOT system peak coincident capacity.[2] As demonstrated in our comments below, these particular generation resources, located in the non-Houston zones, are those that will lose significant revenues upon implementation of marginal losses, creating further risk for resource adequacy in ERCOT.

The Brattle Group performed a production cost study ("Brattle Study") using Power System Optimizer software to simulate current ERCOT market dispatch as compared with the expected ERCOT market dispatch and pricing, using a marginal loss component. The modeling analyzed a 2018 study case on an hourly basis for the full year. While the paper submitted by NRG and Calpine referenced an expected $100 million in annual production cost savings in PJM,[3] what the Brattle Group's modeling shows for ERCOT is that a mere $8.6 million in

[1] Case 47199-30, "FIRST SOLAR INC., VISTRA ENERGY CORP., AND WIND COALITION," filed 10/12/2017
[2] ERCOT Capacity, Demand, and Reserves Report, May 2018, Summer Capacities
[3] William W. Hogan & Susan L. Pope (FTI Consulting, Inc.), *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, p. 42 (May 9, 2017).

production cost savings out of $6,784 million in overall production costs might be achievable – a savings of only 0.13%. The production cost savings estimated by Brattle are of a nearly identical (and miniscule) magnitude to the $11.3 million in savings identified in ERCOT's analysis, despite using a different test year with different assumptions about the generation portfolio and transmission system topology.[4] The Brattle Group's modeling also shows, consistent with ERCOT's simulation, that that savings would come at the expense of a $239 million reduction in generator net revenues, which, in the Commenters' view, would introduce a significant new challenge to the financial viability of existing generation in West and North Texas. Again, the reduction in generator net revenues identified by the Brattle analysis is similar in magnitude to ERCOT's projection.[5] Moreover, the modeling shows that the absolute reduction of generation (0.27%) is twice as much as the production cost savings (0.13%), because adding a marginal loss component would cause less efficient, more costly thermal generation in and around Houston to generate in place of more efficient, less costly generation that is sited further from the calculated center of ERCOT load ultimately impacting retail consumers as described below.

RESPONSES

1. What are the benefits of implementing the use of marginal transmission losses rather than average transmission losses in the Electric Reliability Council of Texas (ERCOT) Security-Constrained Economic Dispatch (SCED) over the long term?

The Brattle Study identified production cost savings of $8.6 million annually out of $6,784 million of overall production costs - a savings of only 0.13%. This is in line with ERCOT's "Base Case" finding of $11.4 million (or 0.117%). However, this insignificant reduction in production costs is accompanied by a massive wealth transfer of $239 million annually in generation net revenues. This wealth transfer shifts revenues to Coastal thermal generation units from nearly all other generators located in ERCOT, giving rise to the likelihood of materially triggering market exit decisions, which would in turn alter any production cost savings estimates.

[4] Case 47199-94, ERCOT, filed 6/29/2018
[5] Ibid.

2. Are the benefits identified in response to Question 1 sufficient to justify the near term costs to the market as a whole? Please consider individual stakeholder implementation costs as well as the costs to ERCOT identified in its study.

No, the benefits are dramatically less than the cost imposed on generators of implementing this new approach. The Brattle Study finds the costs to generators to be a $239 million reduction in net revenues annually, in line with ERCOT's identified revenue loss to generators of $212.5 million. Notably, the $239 million impact is inclusive of an $11.8 million benefit to combined cycle and coal units in the Coast weather zone – that is, marginal losses would reduce revenues to a majority of generators throughout the state (and even to other generators in the Coast zone, particularly nuclear) by $250.7 million to support a relatively small revenue boost to a handful of Houston-area thermal generators. This past summer, ERCOT experienced record low reserve margins, a result of generator retirements and limited near term appetite for new investments in much needed generation to provide resource adequacy. In such an environment, implementing marginal losses would further dampen generator *net* revenues by an estimated quarter of a billion dollars each year, risking additional resource adequacy concerns while providing little if any benefit and potentially harming end users as described in Question 3.

3. What are the effects on retail customers and the retail market from the implementation of marginal transmission losses?

The Brattle Study did not evaluate impacts to the retail market or retail customers. It does, however, note that implementation of marginal losses would result in an overcollection of the cost of transmission losses of $205 million. The study notes that the allocation of that over-collection among loads and generators would be subject to a separate policy decision. That allocation decision would inherently create winners and losers in the retail market, due to discrepancies between who pays more for losses (through their energy price) and how the over-collection is redistributed.

The Brattle Study indicates that consumers may realize a benefit from the implementation of marginal losses of approximately $38 million. However, it is important to note that both Brattle's and other studies have shown that the savings are not uniformly allocated across all consumers. In fact, consumers in major economic hubs of the state could be deprived of accessing the lowest-cost energy and ultimately endure higher energy costs. It would be highly speculative to draw conclusions based upon a single-year analysis because it does not address other second order effects that may arise from marginal losses implementation. The impact of lower generator revenues on generator retirements, reserve margins, reliability, and prices could cause significant adverse impacts on customers and the retail market as a whole.

5. What costs would be incurred by market participants if marginal losses were implemented in the ERCOT market? Please provide an estimate of the costs that would be incurred by your company or companies or customers represented by your organization. Please describe the elements of those costs.

The Brattle Study estimates that implementation of marginal losses would result in an annual net revenue loss of $239 million for a majority of ERCOT generators, including approximately $94 million in lost revenue for thermal units outside of the Coast and South weather zones. Total generator revenues would decrease by $248 million, including $233 million in decreased energy revenues and $15 million in decreased ancillary service revenues and uplift payments. This would be offset by $8.6 million in decreased variable costs. As noted in response to Question 2, the revenue loss to most generators would exceed $250 million; the total generator net revenue reduction figure includes the offset of the $11.8 million wealth transfer to combined cycle and coal generators in the Coast weather zone which is the area around Houston.

8. What are the effects on reliability on the ERCOT grid of using marginal transmission losses instead of average transmission losses in SCED?

ERCOT's modeling of the impact on marginal losses in SCED should raise significant concerns that the implementation of marginal losses will negatively impact reliability. As discussed in our answer to Question 2, based on the lost revenue for generators in the Brattle Study, investor appetite to support new generation would rationally be reduced. Given already tight reserves in ERCOT, new generation is needed to meet growing demand: ERCOT's latest Capacity, Demand, and Reserve (CDR) Report forecasts 7,258 MW[6] of new generation capacity to meet peak demand coming online through 2021. However, it is unclear how much, if any, of that projected capacity has or will receive financing, or if construction will begin. Without the assumed additional new generation in the CDR Report, ERCOT's planning reserve margin would fall to 4.3% by 2020, and 2.4% by 2021.

6 ERCOT May 2018 CDR

9. What effects, if any, would marginal transmission losses have on grid hardening and resilience?

The Brattle Study finds that the implementation of marginal losses would shift thermal dispatch away from the East, North, North Central, West, Far West, South Central, and to a lesser degree, South weather zones, dispatching resources located in the Coast (mainly Houston area) region of ERCOT. While it is difficult to project the impact of this shift, and the possibility that generators in the non-Coast zones may become uneconomic as a result, a meaningful shift in generator output toward the Coastal (and to a lesser degree, South) weather zones should raise serious questions regarding system resilience against disasters such as hurricanes, which commonly impact these regions. Marginal losses would have no impact on renewable generator output – only changing the revenue received by those resources. In addition, as described previously, marginal losses implementation could adversely affect grid resilience by spurring additional, unanticipated generation retirements thereby reducing resource adequacy and fuel diversity.

11. How would a decision to implement marginal transmission losses affect investment in new generation resources in ERCOT over the next five years, the next 10 years, and in the years beyond 10 years?

Based on ERCOT forecasts, utility scale solar is expected to be the largest contributor to new ERCOT capacity over the next 15 years. The "Current Trends" scenario in the upcoming Long-Term System Assessment ("LTSA") report currently forecasts that 14,400 MW of new utility solar generation, 5,750 MW of new combined cycle gas generation, and 3,000 MW of new wind generation will be installed in ERCOT over the next 10 years.[7] These projections are not determinative, and are developed to aid in ERCOT transmission planning. Regardless, they demonstrate that utility scale solar, combined cycle gas turbines, and wind are likely to represent the bulk of new generation investment over the foreseeable future. Marginal losses would not likely change the makeup of future investments, but it may lead to a delay in new installations and a reduction in the total amount of investment that could be attracted in total. While not explicitly modeled in the Brattle Study, the results would imply a foreseeable lower level of

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[7] ERCOT, 2018 LTSA Update, Regional Planning Group Meeting, April 24, 2018 (available at http://www.ercot.com/content/wcm/key_documents_lists/138684 2018_LTSA_Update_April_RPG.pptx).

future investment for resources negatively impacted by a transition to marginal losses than would otherwise exist under the current average cost allocation methodology.

The Brattle Study finds that net revenues for solar in Texas would decline $5.7 million as a result of marginal losses implementation. Currently investment in solar is driven by customer demand and investor confidence in the stability of the ERCOT market. Marginal losses would both reduce that confidence and reduce the value of solar installations despite no change in energy output. It is difficult to quantify this impact without further modeling, and such modeling would be highly sensitive to the methodology under which marginal losses are implemented.

The Brattle Study estimates that marginal losses would reduce generator net revenues for combined cycle, coal and wind generation resources located throughout ERCOT by $29 million, $40 million and $151 million respectively. With the severely limited ability to site new combined cycle gas generation in non-attainment zones along the coast and in Houston , this would further reduce opportunities to develop new natural gas combined cycles to meet ERCOT needs. This raises questions regarding both new investments and the potential for loss of existing peaking capacity in ERCOT due to reduced revenue.

The only revenues positively impacted by a transition to marginal losses identified in the Brattle Study would be combined cycle and coal generation in the Coastal, South, and South Central weather zones, mainly in the Houston area. It is worth noting that the Brattle Study was conducted prior to the coal plant retirements that occurred in early 2018. There is also one additional coal unit, located in the South Central zone, that is expected to close this year that was included in Brattle's analysis due to its use of a 2018 reference scenario.

12. How would the implementation of marginal transmission losses affect the composition of the generation fleet in ERCOT?

As discussed in our answer to Question 9, the theoretical impact to the composition of the generation fleet from the implementation of marginal losses would be the geographic shifting of thermal generator output toward the coastal weather zones. Due to environmental constraints and the relative lack of renewable energy drivers in those zones compared to other parts of the state, marginal losses is unlikely to drive significant new development of any types of resources in and around Houston. While marginal losses would rationally dampen investor appetite in new generation as discussed in Question 2, thereby delaying the addition of new capacity, the technology composition of new capacity entering the ERCOT generation fleet is unlikely to change. Simply put, as shown by numerous analyses, including ERCOT's Long-Term System Assessment, a combination of new natural gas, solar, and wind generation are projected to be the most cost-effective composition to meet system needs going forward.

The Brattle Study demonstrates that while the implementation of marginal losses will shift generator revenues toward those located in the coastal weather zones, it will not influence dispatch of solar and wind. This outcome emphasizes the fact that even with imposition of a marginal loss penalty; the technologies that are most cost-competitive today are expected to remain cost competitive in ERCOT's future.

13. Assuming the Commission decided to go forward with implementation of marginal transmission losses, what are the key issues related to determining the appropriate treatment and allocation of the marginal transmission loss surplus revenues?

The ERCOT analysis findings are broadly in line with the Brattle Study analysis in terms of the production cost savings and the revenue loss to generators. However, the ERCOT study fails to evaluate several key potential costs to market participants and other impacts that would be necessary for the Commission to fully evaluate before deciding to incorporate marginal losses in SCED. The ERCOT analysis does not quantify the overcollection of marginal loss payments, which according to the Brattle Study, would total $205 million annually. The proper allocation of these substantial over-collected revenues poses a serious policy question that the Commission must consider in evaluating a transition to marginal losses.

14. Does the ERCOT analysis of the benefits of including marginal transmission losses in SCED accurately measure such benefits? Are potential costs to the market or to market participants adequately accounted for?

The ERCOT analysis does provide detail regarding the regional and technology breakdown of expected changes to LMPs and order of dispatch, and the results appear largely consistent with the Brattle Study. These studies help to identify some of the potential costs to some market participants. However, these impacts should also be evaluated in the context of long-term resource adequacy and system reliability.

The ERCOT analysis did not, however, evaluate whether changes in thermal unit dispatch are viable given constraints on criteria pollutant emissions in the coastal and Houston areas of ERCOT. The impact of additional emissions of SO2, NOx, and other ozone precursors on non-compliance regions as a result of increased dispatch of Houston area thermal resources and the decreased dispatch of most other thermal units, may create additional costs or even lead to new environmental restrictions on thermal generation in those regions. While this effect may be difficult to quantify fully, it must be evaluated to allow the Commission and market participants to evaluate the full impact of this proposed change. Additionally, ERCOT's analysis was for a single year. It is difficult to determine the total impact to market participants, particularly consumers, with only one year's worth of data that does not fully flesh out the true impact of marginal losses implementation. While we have identified in these comments some of the shortcomings of implementing marginal losses, "we don't know what we don't know," and one year's worth of data does not come close to highlighting the true effects of moving forward with this policy decision.

15. What ERCOT operational changes would need to be made that are not considered in ERCOT' s studies?

Regarding solar and wind generation, based on the findings of the Brattle Study, in general, marginal losses is unlikely to impact dispatch or operation. Because of their low marginal cost, solar and wind units will likely continue to be dispatched as one of the lowest marginal cost resources when available. The sole effect of this policy to existing solar and wind power in Texas would be to penalize installations by reducing the revenue that was reasonably expected when projects were being financed and developed. Such a change would likely chill investor confidence in the ERCOT market. It is also unclear how a change of this nature will impair collateral and impact off-take agreements and other forms of financing generation projects.

While the Brattle Study did not delve into operational implications for ERCOT, the reduction in both prices and dispatched volumes that the Brattle Study estimated for most thermal resources naturally raises questions about economic viability of thermal generation resources outside of the Coast weather zone. Any operational suspensions or retirements of existing thermal capacity that the implementation of marginal losses would likely have implications for ERCOT's operations – but those implications would differ depending on the resources in question.

17. Assuming that the implementation of marginal transmission losses results in the location of generation closer to load, what advantages and disadvantages would there be during an emergency event or a market restart to having generation located closer to load?

This outcome is unlikely. Marginal losses may provide some limited incentive to locate generation closer to the "center of load" in ERCOT based on the results from the Brattle Study. However, the reality is that marginal losses would primarily penalize existing generators and reduce investor confidence in the market until investors are able to observe the true impact of the proposed policy change. Thus, any signal to locate new resources closer to the "center of load" would remain weak relative to existing competitive market signals including nodal pricing, congestion pricing, resource/fuel availability, and siting constraints.

The incentive from marginal losses will not be to locate generation closer to all load, but rather closer to the "center of load" as identified by a yet to be determined methodology. To the extent that this change would result in the location of generation closer to the ERCOT "center of load," the lack of black start capability in those areas farther from the Houston area could risk additional reliability impacts. If marginal losses do influence generator location as purported, they may reduce black start capabilities in load centers located further from the "center of load," such as along the I-35 corridor.

CONCLUSION

In short, given the magnitude of disruption to most generators when compared to the negligible and tenuous production cost savings, Commenters are convinced that the implementation of a marginal loss component would not be beneficial in ERCOT. Commenters appreciate the Commission's deliberate approach to analyzing the proposed changes to ERCOT's market design.

Respectfully submitted,

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PROJECT NO. 47199

PROJECT TO ASSESS PRICE-FORMATION RULES IN ERCOT'S ENERGY-ONLY MARKET	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

ANALYSIS OF MARGINAL LOSSES PROPOSAL

COME NOW First Solar Inc., Vistra Energy Corp., and the Wind Coalition (collectively, "Commenters"), and file a copy of *Impacts of Marginal Loss Implementation in ERCOT* by the Brattle Group. Commenters hired the Brattle Group to perform an independent analysis of the potential impacts of implementing a marginal loss methodology for pricing and dispatching generation in ERCOT, as proposed by NRG and Calpine in the current Project.

The Brattle Group performed a production cost study using Power System Optimizer software to simulate current ERCOT market dispatch as compared with the expected ERCOT market dispatch and pricing using a marginal loss component. The modeling analyzed a 2018 study case on an hourly basis for the full year. While the paper submitted by NRG and Calpine referenced an expected $100 million in annual savings in PJM,[1] what the Brattle Group's modeling shows is only $8.6 million in production cost savings could be realized in ERCOT – a savings of only 0.13%. The Brattle Group's modeling also shows that that savings would come in the form of a $239 million reduction in generator net revenues, which, in the Commenters view, would introduce a significant new challenge to the financial viability of existing generation in West and North Texas. Moreover, the modeling shows that the absolute reduction of generation is twice as much as the production cost savings, because adding a marginal loss component would cause less efficient thermal generation in and around Houston to generate in place of more efficient generation that is sited further from the center of load.

In short, given the magnitude of disruption to certain generators when compared to the very small production cost savings, Commenters are convinced that the implementation of a marginal loss component would not be beneficial in ERCOT, and plan to elaborate further on the associated policy issues in subsequent comments.

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[1] William W. Hogan & Susan L. Pope (FTI Consulting, Inc.), *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, p. 42 (May 9, 2017).

Commenters appreciate the Commission's deliberate approach to analyzing the proposed changes to ERCOT's market design, and look forward to discussing these and other policy issues in future comments.

Respectfully submitted,

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Impacts of Marginal Loss Implementation in ERCOT

2018 Reference Scenario Results

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October 11, 2017

THE Brattle GROUP

Disclaimer

This report was prepared for Ad Hoc Group that includes Vistra Energy, The Wind Coalition, and First Solar. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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Overview of Analysis

Executive Summary

- Implementing marginal losses reduces system production costs, transmission losses, and generator net revenues.
  - Would reduce system production cost by **0.13% per year** (**$8.6 million out of $6,784 million**).
  - Would reduce system-wide load inclusive of losses by **0.27% per year** (**1.06 TWh out of 402 TWh**).
  - Would decrease generator net revenues by **7.54% per year** (**$239 million out of $3,166 million** before potential allocation of over-collected ML payments).
    - $248 million reduction in revenues, offset by $8.6 million reduction in variable costs.
- Marginal loss implementation changes load LMPs and payments:
  - Annual average LMP (ERCOT-wide) increases by 2.06% ($0.50/MWh increase from $24.33/MWh).
  - LMP payments by load decrease by **$38 million** (before potential allocation of over-collected ML payments).
    - Lower payments in North ($52 million) and West ($47 million) load zones.
    - Higher payments in Houston ($53 million) and South ($8 million) load zones.
- Over-collection of marginal loss payments would be **$205 million**—allocation of these revenues would be subject to a separate policy decision.
- Generation resources closer to the center of load are dispatched more than remote resources.
  - Increased dispatch of higher cost generation resources near center of load offsets the production cost savings coming from the reduction in losses.
  - Generation in Coast, South, and South Central zones increases by 14.2 TWh, offset by a decrease of 15.3 TWh in other weather zones.

Study Objective and Method

Assess the impact of marginal loss (ML) implementation in the ERCOT Market on system production costs, LMPs, and shift in payments/revenues among market participants.

- Modeled the ERCOT Day-Ahead Market under a Reference Scenario (most likely future world in 2018, given what we know today) to quantify impacts.
  - Compared the Base Case (without Marginal Losses) and Marginal Loss Case
  - Assumed mandatory participation of all market players.
  - Base Case calibrated to historical data without the Houston Import Project ("HIP"), then added HIP in mid-year 2018.
  - Marginal Loss Case was run using Base Case assumptions but with marginal losses implemented. All else is equal.

This study does <u>not</u> account for:

- Impacts of changing locational price signals on economics of entry/exit decisions (including environmental constraints on siting new generation);
- Dynamic impacts of potential changes in entry/exit decisions on market prices and system costs; and
- Implementation costs of marginal loss.

Overview of Analysis
Model Calibration

We calibrated the model (without ML implementation) against market outcomes in recent years.

- The Reference Scenario modeled 2018 without HIP and showed model results on zonal congestion patterns, implied market heat rates and generation capacity factors are either similar to actuals during 2014-16 or can be explained by the changes in market fundamentals.
  - Total modeled 2018 congestion cost of $341 million, compared to $497 million actual congestion cost in 2016 and $352 million in 2015.
    - 2016 congestion was higher than other recent years due to system upgrade related outages. 2018 congestion is highest in the Panhandle constraint, consistent with ERCOT's expectations[1]
  - Modeled capacity factors are consistent with recent years by unit type and zone. Except for:
    - Low modeled capacity factors for Gas Turbine/Internal Combustion Engine generators, as expected when modeling DA conditions. High modeled capacity factors for the Combined Cycle generators in the West, due to higher gas price differential than recent years.
- The 2014 Test Case (with load, installed wind capacity, and natural gas basis differentials consistent with 2014 levels) had modeled transmission losses of 7.1 TWh similar to the 6.2 TWh of actual losses in 2014.

Source 1: December 2016 ERCOT Report on Existing and Potential Constraints and Needs

Key Modeling Assumptions

System Load (w/o ML implementation)

- Total annual energy of 402 TWh. This includes 364 TWh from ERCOT Load and T&D losses, and an additional 38 TWh of Private Use Network (PUN) load.
- Total peak load of 78.3 GW. This includes 74 GW from ERCOT load and T&D losses, and an additional 4.3 GW from PUN load.
- PUN load is modeled as flat hourly load throughout the year.

Generation

- The total modeled generation capacity (as of January 1, 2018) is 102 GW (21 GW of Wind):
  - This includes 3 GW (2.2 GW of Wind) that comes online in 2017 and excludes 0.6 GW that retired in 2016.
  - An additional 3 GW (2.6 GW of Wind) of generation is added and 0.8 GW is retired during 2018.
- PUN generation is dispatched similarly to other generation (modeled separately from PUN load), but committed at minimum operating limit.
- Planned and forced generation outages are modeled based on information from NERC.

Key Modeling Assumptions (cont'd)

Transmission

- Houston Import Project coming online on June 1, 2018.
- No transmission outages, forced or planned, were accounted for in the simulation.
- No modeled transactions over DC-ties.

Reference Bus

- Distributed reference bus that represents the center of ERCOT load ("center of load").
- Note: The selection of a reference bus impacts the loss and congestion components of LMPs, thus impacting payments to CRRs and loss payments/refunds.

Overview of Analysis

Marginal Loss Methodology

This study implements marginal losses with full marginal loss pricing, consistent with the current marginal loss implementations in the U.S. RTOs. Traditionally, there have been two methods:

- **Marginal Loss Pricing:** Under this method, transmission losses are priced according to their marginal loss factor. This results in over collection of loss revenues, by a factor of 2. These revenues will be refunded by the market operator.
- **Scaled Marginal Loss Pricing:** Under scaled marginal loss pricing the marginal loss factor of LMP is reduced to prevent the over collection of loss revenues. This reduction can be done in different ways, and may distort the incentives to generators for least-cost dispatch.

Sources:

Leslie Liu and Assef Zobian, "The Importance of Marginal Loss Pricing in an RTO Environment." Accessed October 4, 2017. http://www.ces-us.com/download/Reports_and_Publications/Losses%20paper%20-%20web.pdf

Laurence D. Kirsch, "Pricing the Grid: Comparing Transmission Rates of the U.S. ISOs." Public Utilities Fortnightly (February 15, 2000) accessed October 4, 2017. https://www.fortnightly.com/fortnightly/2000/02-0/pricing-grid-comparing-transmission-rates-us-isos

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Change in Losses

Implementing marginal losses reduces system transmission losses by 0.27% of the 393 TWh of total energy served (or a reduction of 1.06 TWh) in 2018.

- Losses are approximately 9.51 TWh in the Base Case and 8.45 TWh in the Marginal Loss Case.

Change in Losses – Reference Scenario

Case	Effective Load (TWh) [1]	Transmission Losses (TWh) [2]	Transmission Losses (% of Effective Load) [3]	Change in Losses (TWh) [4]
Base Case	393	9.51	2.42%	
Marginal Loss Case	393	8.45	2.15%	-1.06

[1]: Load Served
[2]: Transmission Losses
[3]: [2]/[1]
[4]: Marginal Loss Case Transmission Losses - Base Case Transmission Losses

- In the peak hour (August 1 HE 16), transmission losses are only reduced by 30 MW (0.04% from 1.67% to 1.63%).
  - Transmission losses (as a % of load) under Base Case are lower during the peak load hour (1.67%) than the annual average since there is more generation from peaking units close to the center of load during this hour.
  - This dispatch pattern means that ML implementation has a lower impact on losses (0.04% reduction) since most generation near the center of load is already running in the Base Case.

Change in Production Costs

Implementing marginal losses reduces system production costs by 0.13% from the Base Case ($8.6 million reduction from $6,784 million).

- Marginal losses increase generation from resources closer to the center of load.
- Marginal cost of generation ($/MWh) is higher in zones near the center of load (i.e., less efficient generators are dispatched in the Marginal Loss Case).
- Therefore, implementing marginal losses reduces production cost by only half as much (0.13%) as it reduces total load plus losses (0.27%).

Production Costs ($ million)

Case	Total Production Costs	Production Cost Savings
Base Case	$6,784	-
Marginal Loss Case	$6,775	$8.6

Base Case Average Marginal Costs ($/MWh)

	Combined Cycle	Coal
Coast	24.8	17.4
South	22.9	17.2
S. Central	21.2	19.4
East	20.7	14.3
N. Central	20.9	16.9
North	21.3	21.7
West	20.3	0.0
Far West	19.0	0.0

Change in Generation

ML implementation shifts generation closer to the center of load (shaded rows).

Change in Generation (TWh)

		Total	CC	Coal	GT	STOG	Nuclear	Biomass	IC	Hydro	Wind	Solar	Storage
Base Case	Coast	**95**	54	14	6	2	20	0	0	0	0	0	0
	South	**38**	14	7	0	0	0	0	0	0	17	0	0
	S. Central	**43**	14	28	0	1	0	0	0	0	0	0	0
	East	**61**	8	53	0	0	0	0	0	0	0	0	0
	N. Central	**77**	30	21	0	0	20	0	0	0	6	0	0
	North	**38**	12	2	0	0	0	0	0	0	24	0	0
	West	**24**	4	0	0	0	0	0	0	0	19	1	0
	Far West	**26**	10	0	0	0	0	0	0	0	14	1	0
	Total	**402**	145	124	7	3	40	0	0	0	80	3	0
Marginal Loss Case	Coast	**105**	62	16	6	2	20	0	0	0	0	0	0
	South	**39**	15	7	0	0	0	0	0	0	17	0	0
	S. Central	**45**	16	29	0	0	0	0	0	0	0	0	0
	East	**54**	6	48	0	0	0	0	0	0	0	0	0
	N. Central	**74**	27	20	0	0	20	0	0	0	6	0	0
	North	**33**	8	2	0	0	0	0	0	0	24	0	0
	West	**24**	4	0	0	0	0	0	0	0	19	1	0
	Far West	**26**	10	0	0	0	0	0	0	0	14	1	0
	Total	**401**	146	122	7	3	40	0	0	0	80	3	0
Delta (Marginal Loss - Base)	Coast	**10**	8	2	0	0	0	0	0	0	0	0	0
	South	**1**	1	0	0	0	0	0	0	0	0	0	0
	S. Central	**3**	2	1	0	0	0	0	0	0	0	0	0
	East	**-7**	-2	-4	0	0	0	0	0	0	0	0	0
	N. Central	**-4**	-3	0	0	0	0	0	0	0	0	0	0
	North	**-5**	-5	0	0	0	0	0	0	0	0	0	0
	West	**0**	0	0	0	0	0	0	0	0	0	0	0
	Far West	**0**	0	0	0	0	0	0	0	0	0	0	0
	Total	**-1**	1	-2	0	0	0	0	0	0	0	0	0

Increase

Decrease

No Significant Change

Change in Average Generator LMPs

Marginal loss implementation impacts on Generator LMPs:

- LMPs increase near the center of load (Houston Load Zone).
- LMPs decrease based on distance from the center of load.
  - North and South Load Zone both decrease.
  - West Load Zone decreases significantly.

Annual Average Generator LMPs by Load Zone ($/MWh, Generation-weighted average)

	Houston	North	South	West	ERCOT
Base Case	$25.11	$24.62	$24.56	$19.62	$23.78
Marginal Loss Case	$25.30	$24.30	$24.23	$17.62	$23.26
Delta	$0.19	-$0.32	-$0.33	-$2.00	-$0.51

Change in Generator Net Revenues

- Marginal loss implementation lowers the net revenues paid out to generators overall, driven by decreasing gen LMPs in remote zones and total generation decrease.
  - Net revenues increase for some classes of thermal generators near center of load.
- Total net revenues across all generation units decline by 7.54% per year ($239 million out of $3,166 million).
  - Total revenues decrease by $248 million.
    - $233 million decrease in energy revenues, $15 million decrease in ancillary service revenues and uplift payments.
  - Revenue decrease is offset by $8.6 million decrease in variable costs.

Generator Net Revenue Change Between Base and ML Cases ($k)

	CC	Coal	GT	STOG	Nuclear	Biomass	IC	Hydro	Wind	Panhandle Wind	Solar	Storage	Total
Coast	$6,963	$4,842	-$864	-$514	-$2,150	$0	$3	$0	$70	$0	$1	$0	**$8,352**
South	-$1,260	$899	-$81	$7	$0	$7	-$67	-$38	-$24,673	$0	$0	$0	**-$25,205**
S. Central	-$1,662	-$11,922	-$17	-$115	$0	$0	-$84	-$280	$0	$0	$2	$0	**-$14,078**
East	-$4,436	-$26,568	-$0	-$46	$0	-$311	$0	$0	$0	$0	-$0	$0	**-$31,362**
N. Central	-$10,899	-$6,789	-$1	$22	-$7,134	$0	$57	-$69	-$8,393	$0	$1	$0	**-$33,205**
North	-$7,945	-$894	-$15	$0	$0	$0	-$91	-$56	-$20,552	-$28,549	-$1,729	-$63	**-$59,895**
West	-$1,695	$0	-$2	$0	$0	$0	$1	-$51	-$40,334	$0	-$664	$0	**-$42,744**
Far West	-$8,332	$0	-$17	$0	$0	$0	-$4	$0	-$28,985	$0	-$3,340	-$78	**-$40,756**
Total	**-$29,266**	**-$40,431**	**-$996**	**-$646**	**-$9,284**	**-$304**	**-$185**	**-$494**	**-$122,866**	**-$28,549**	**-$5,729**	**-$141**	**-$238,891**

Change in Average Load LMPs

Marginal loss implementation would increase annual average load LMPs by 2% ($0.50/MWh on average across ERCOT).

- Implementation of losses increases cost of marginal generator—raising average prices in ERCOT.
- Offset in the West zone (distant from center of load) by highly negative MLC, and exacerbated in areas near center of load by positive MLC.

Annual Average Load Zone LMP ($/MWh, Load-weighted average)

	Houston	North	South	West	ERCOT
Base Case	$24.28	$24.43	$24.46	$23.73	$24.33
Marginal Loss Case	$24.99	$24.79	$25.13	$23.34	$24.83
Delta	$0.71	$0.37	$0.67	-$0.38	$0.50

Annual Average Load Zone LMP Components ($/MWh, Load-weighted average)

		Houston	North	South	West
Marginal Energy Component	Base Case	24.20	24.49	24.38	23.97
	Marginal Loss Case	24.63	24.97	24.84	24.47
Marginal Congestion Component	Base Case	0.08	-0.06	0.07	-0.25
	Marginal Loss Case	0.01	0.00	0.04	-0.15
Marginal Loss Component	Base Case	0	0	0	0
	Marginal Loss Case	0.35	-0.17	0.25	-0.98

Change in Load Payments

Marginal loss implementation would reduce the total load payments in ERCOT by $38 million (before loss refunds), driven by 9.6 TWh decrease in volume subject to LMP payment (but offset by the increase in the average load LMP).

- Under ML settlement, load pays for marginal losses as part of the MLC of LMPs. Therefore, load is charged the LMPs for the metered load (not grossed up for average losses) to avoid paying for losses both in the LMPs and in the volume.
- Load payments in the North and West zones decrease since the impact of the reduction in load volume is larger than the impact of the increase in load LMPs.
- The reverse effects applies to the Houston and South zones (small reduction in load volume, and large increase in LMPs).

Over-collection of ML payments would be $205 million.

- Allocating over-collected ML payments among loads and generators would be subject to a separate policy decision.
- Loss refund calculated as (Nodal Load * MLC) – (Nodal Gen * MLC) – (System Losses * MEC).

Total Annual Load (TWh)

	Houston	North	South	West	ERCOT	
Base Case	121.7	136.0	111.3	33.1	402.2	Including Tx Losses
Marginal Loss Case	120.4	131.9	108.7	31.7	392.6	Excluding Tx Losses
Delta	-1.4	-4.1	-2.7	-1.5	-9.6	

Annual Load Zone LMP Payments ($ Millions, before loss refunds)

	Houston	North	South	West	ERCOT
Base Case	$2,956	$3,323	$2,722	$786	$9,786
Marginal Loss Case	$3,009	$3,271	$2,730	$739	$9,748
Delta	$53	-$52	$8	-$47	-$38

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