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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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 not 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.

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.

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.

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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

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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

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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

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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**

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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

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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
Marginal Loss Case	120.4	131.9	108.7	31.7	392.6
Delta	-1.4	-4.1	-2.7	-1.5	-9.6

Base Case: Including Tx Losses
Marginal Loss Case: Excluding Tx Losses

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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