Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch

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1. Introduction

At the request of the Public Utility Commission of Texas (PUCT), ERCOT has conducted an analysis of the expected benefits from incorporating marginal losses into the Security-Constrained Economic Dispatch (SCED) process. When electricity is produced in one location and consumed at another location within the power grid, the electricity flows through the transmission and distribution system and some of it is lost. The losses vary depending on the distance the electricity is traveling and the voltage of the circuits. In ERCOT's current market design, these losses are not reflected in Locational Marginal Prices (LMPs) and are compensated for on a system-wide average basis. Incorporating marginal losses into the SCED process results in transmission losses being considered during the dispatch of resources and reflected in the dispatch outcomes and the resulting LMPs.

This benefit analysis was conducted using the same methodology that is used to conduct the economic analysis of transmission projects for the Regional Transmission Plan and for Regional Planning Group independent reviews (see Appendix A of the Regional Transmission Plan report for complete details[1]). The Uplan Network Power Model version 10.4, a production cost model that includes a security-constrained unit commitment and economic dispatch algorithm, was used to simulate expected system conditions in the year 2020 for this analysis.

This benefit analysis used the same data input assumptions that were used in the 2017 Regional Transmission Plan, with the following exceptions: The natural gas price forecast for the base case of this analysis was updated to be consistent with the natural gas price forecast currently being used in the development of the 2018 Regional Transmission Plan (an annual average cost of $3.55/MMBTU). This natural gas price forecast is based on the High Oil and Gas Resource and Technology forecast in the 2018 Energy Information Agency (EIA) Annual Energy Outlook (AEO). In addition, two other gas prices were used to show the sensitivity of the model results to this input assumption: one sensitivity case used a lower gas price ($1/MMBTU lower or $2.55/MMBTU); the second sensitivity case used a higher gas price ($3.96/MMBTU, based on the natural gas price forecast from the Reference Case in the 2018 EIA AEO). All generating units that met the criteria described in Planning Guide Section 6.9 as of February 1, 2018, were included in the study, and the recently retired generating units were removed from the model database.

For each of the three sets of analyses (the base case and the two natural gas price sensitivities), two model runs were conducted. The first run was conducted consistent with the current system dispatch. In the second run, the system dispatch included consideration of marginal losses. The differences between the outputs of these runs, as described in this summary, indicate the expected benefits from the proposed switch to incorporating marginal losses in system dispatch.

[1] http://www.ercot.com/content/wcm/lists/114740/2017_RTP_PublicVersion.zip

2. Results

This analysis quantifies the benefits resulting from implementing marginal losses in three different ways: changes in total system production costs; changes in the portion of consumer costs that are paid to generators (i.e., generator revenues); and changes in total consumer costs.

2.1. Production Costs

Production costs are the costs incurred by generators to produce electricity—specifically fuel costs, variable operations and maintenance costs, and unit start-up costs. Production cost savings are indicative of increased system efficiency. Production cost savings do not necessarily represent immediate savings to consumers, as these savings can flow to generators, consumers, or both. The table below shows the annual production costs from the three scenarios evaluated in this study.

Annual Production Costs

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	7,651.5	9,723.0	10,477.9
Marginal Losses ($M)	7,638.0	9,711.6	10,478.8
Savings ($M)	13.4	11.4	-0.9

These production cost savings derive primarily from reductions in the amount of energy required to serve the equivalent amount of customer demand, as incorporating marginal losses into economic dispatch reduces power flows on the transmission system and thus reduces transmission system losses. The lack of production cost savings in the high gas price case is likely due in part to the increased competitiveness of coal-fired units, which are more distant from urban load centers, as gas prices increase. In the three cases studied, including marginal losses in energy dispatch reduced the total generation by approximately 800-1,200 GWh per year, as shown in the following table.

Total Annual Generation

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses (GWh)	431,027	431,279	431,270
Marginal Losses (GWh)	430,200	430,200	430,018

2.2. Consumer Costs

One way to assess changes in consumer costs is to evaluate changes in generator revenues. Money paid to generators is a major component of the overall costs to consumers, and changes in generator revenues can be expected to directly affect consumers. Before the PUCT amended its rules in 2012, ERCOT considered the change in generator revenues as one criterion for justifying economic transmission projects.

The following table shows the annual generator revenues for the three scenarios evaluated in the study. While generators have multiple revenue streams, these revenues are based on energy sales only and do not take into account generator revenues due to providing ancillary services.

Annual Generator Revenues

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	9,666.4	12,136.3	13,076.5
Marginal Losses ($M)	9,498.7	11,923.8	12,852.0
Revenue Change ($M)	-167.7	-212.5	-224.5

Breaking down the generator revenue results by Load Zone indicates a significant transfer of revenues within the generation fleet—specifically from generators in the West and North Load Zones to generators in the Houston zone.

Annual Generator Revenue Changes by Load Zone

	Low Gas Price Case	Base Case	High Gas Price Case
Houston Zone ($M)	172.0	216.4	257.6
North Zone ($M)	-222.0	-331.9	-415.3
South Zone ($M)	38.3	86.8	125.9
West Zone ($M)	-153.0	-180.7	-190.2

Again, this table provides the marginal loss result minus the average loss result, so a negative number indicates a reduction in generator revenues. The positive numbers for the Houston and South zones indicate that generators in these zones in aggregate would be expected to have higher revenues if marginal losses were implemented.

The model output also indicates that wind generation units in West Texas do not show a reduction in energy production due to including marginal losses in the system dispatch, just a reduction in the price they are paid for the energy they produce. However, the reductions in generator revenues for thermal generation units in the West and North Load Zones reflect both reduced production and lower prices for the energy they produce.

The analysis of changes in generator revenues described above indicates cost-savings for consumers across the system. However, these results do not indicate any expected differential impacts to consumers in different parts of the grid.[2] Evaluating changes to LMPs alone is also not informative because 1) LMPs in systems with average losses do not include a cost component for losses, whereas systems with marginal losses do include the cost of losses in the LMPs; and 2) in systems with average losses, the energy losses are accounted for in the energy usage charged to each customer rather than in the cost of the electricity. As a result, the LMPs in the two runs are not directly comparable.

When evaluating the consumer impacts resulting from switching from average losses to marginal losses by zone, one must evaluate the combined impact of changes to both the amount of energy charged to consumers as well as the cost of that energy. The following table provides these results, but it should be noted that the net costs to consumers may differ based on the specific arrangements between customers and their Load Serving Entities (LSEs). The congestion cost components of the payments in the table below are capable of being hedged through the Congestion Revenue Rights (CRR) market, which may result in additional payments or charges to consumers in Real-Time. In addition, any excess revenues derived from the loss components of the consumer payments in the marginal loss scenarios would presumably be redistributed, although the manner in which this would be done has not yet been determined.

Annual Changes in Total Consumer Costs by Load Zone

	Low Gas Price Case	Base Case	High Gas Price Case
Houston Zone ($M)	21.9	-21.8	-58.5
North Zone ($M)	-62.2	-73.6	-81.3
South Zone ($M)	-13.8	-18.5	-12.1
West Zone ($M)	-22.0	-21.1	-18.4
Total ($M)	-76.1	-135.0	-170.4

[2] The preceding table showing impacts to generator revenues in each Load Zone does not necessarily reflect the impact to consumers in the corresponding Load Zones.

These results are calculated by subtracting the average loss result from the marginal loss result, so negative numbers indicate savings to consumers. The one positive number, for the Houston zone in the low gas price case, indicates that consumer costs would be expected to rise in the Houston zone following implementation of marginal losses if gas prices are low.

2.3. Unit Revenue Shortfalls

In addition to the results indicating reductions in system production costs and system-wide consumer costs, the Uplan model results also indicate that unit revenue shortfalls would be expected to increase if marginal losses were implemented. These results are provided in the following table.

Annual Unit Revenue Shortfalls

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	98.9	152.7	203.9
Marginal Losses ($M)	120.4	196.4	269.8

The Uplan simulation model does not simulate the ERCOT Day-Ahead Market (DAM) or the ERCOT Reliability Unit Commitment (RUC) process, both of which provide the opportunity for units to receive make-whole payments if they do not make adequate revenue through real-time energy prices to cover their operating costs. However, the Uplan model does track the difference between the operating costs of units committed to maintain local grid reliability and their daily energy revenue. (The model refers to these revenue shortfalls as “No Load and Start-up Revenue.”)

The increased revenue shortfalls in the table above could indicate that implementing marginal losses would result in an increase in units being committed out of merit order so as to maintain local reliability and an increase in unit make-whole payments. It should also be noted that these revenue shortfalls are included in the generator revenue changes described in the previous section. So, even with these increased costs for running units out of merit, the model is still showing significant reductions in generator revenues.

One possible reason for an increase in unit revenue shortfalls may be a corresponding increase in unit startup costs. These results are provided in the following table.

Unit Startup Costs

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	69.3	72.6	73.5
Marginal Losses ($M)	82.5	107.7	127.0

It is not clear from the model results why the start-up costs increase in the marginal losses runs or why the difference grows as the gas price increases. Start-up costs in these simulations are not tied to gas prices in the model input, so the increased costs reflect an increase in the number of unit starts and/or an increase in the number of starts of units with higher start-up costs.

The ERCOT market design does not necessarily ensure system-wide optimization of start-up decisions. These commitment decisions are made independently by resource owners based on their expectations of future on-peak and off-peak market prices. The Uplan model incorporates a simplistic representation of this start-up process, and while the Uplan algorithm cannot predict changes in startup decisions by resource owners, it does suggest a potential change in system costs. As these increased start-up costs would not necessarily be reflected in LMPs, they could be part of the reason that the model shows unit revenue shortfalls increasing in the marginal loss simulations.

3. Conclusion

In summary, this analysis indicates that both production cost savings and reductions in consumer costs are likely results of incorporating marginal losses in system dispatch decisions. The model results also project increases in unit make-whole payments and unit startup costs, which could indicate possible additional costs if marginal losses are implemented.