Control Number: 48539

Item Number: 2

Addendum StartPage: 0

OPEN MEETING COVER SHEET

MEETING DATE: August 9, 2018

DATE DELIVERED: August 2, 2018

AGENDA ITEM NO.: 14, 15, and 16

CAPTION: Project No. 48539, *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch*
Project No. 48540, Review of Real-Time Co-Optimization in the ERCOT Market
Project No. 48551, Review of Summer 2018 ERCOT Market Performance

ACTION REQUESTED: Discussion and possible action with respect to publication of questions for comment.

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- Benter, Tammy (4)
- Gonzales, Adriana (if rulemaking)

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Public Utility Commission of Texas

Memorandum

TO: Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin

FROM: Mark Bryant, Competitive Markets Division
Connie Corona, Competitive Markets Division

DATE: August 2, 2018

RE: **Open Meeting Items No. 14, No. 15, and No. 16** Project No. 48539, *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch*
Project No. 48540, Review of Real-Time Co-Optimization in the ERCOT Market
Project No. 48551, Review of Summer 2018 ERCOT Market Performance

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On June 29, 2018, ERCOT filed a Report of its studies of the benefits of real-time co-optimization of energy and ancillary services ("RTC") and the benefits of including marginal losses in security-constrained economic dispatch ("marginal losses"). On the same date Potomac Economics, the ERCOT Independent Market Monitor (IMM), filed a separate Report on its Simulation of Real-Time Co-optimization of the Energy-Only Market. Consistent with the Commission's direction at the July 12 open meeting, this memorandum proposes next steps for the Commission's review of these studies. Background on the development of these studies and a brief summary of the results are also included.

Technical review of the studies

Both the ERCOT and IMM analyses of RTC and the ERCOT analysis of marginal losses use complex models, a large number of assumptions that determine inputs to the models, and vast amounts of data. On July 27, ERCOT issued Market Notice M-A062918-02, defining the process for submitting questions relating to the models used to produce the studies to Dan Jones, ERCOT Principal Commercial Operations, at Dan.Jones@ercot.com.

Identification of policy issues

Commission staff recently has opened two new projects: Project No. 48540, *Review of Real-Time Co-optimization in the ERCOT Market* and Project No. 48539, *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch* to facilitate consideration of the RTC and marginal losses proposals. Attached to this memorandum in Attachment A and Attachment B are questions proposed by Staff for publication in the *Texas Register.*

Staff believes that the quality of comment on the policy issues surrounding these proposals will be improved if sufficient time is allowed for stakeholders to develop a thorough understanding of the ERCOT and IMM studies and the implications of the study results for the ERCOT market. Accordingly, Staff recommends that the Commission allow 45 days for response to published questions for comment. Following receipt of stakeholder Comments, staff suggests that the commission convene a workshop on each proposal, perhaps in the late September to early October time frame.

Background

Real-Time Co-optimization of Energy and Ancillary Services (RTC) and pricing of marginal losses were two among several recommendations of a paper by Prof. William W. Hogan and Dr. Susan L. Pope filed in Project No. 40000 on May 10, 2017.[1] Project 47199 was created on May 22, 2017 to assess the recommendations in the Hogan-Pope paper and to determine which, if any, should be implemented.

RTC has been a topic of discussion at the Commission and in the ERCOT stakeholder process for many years, and implementation of RTC has been a long-standing recommendation of the IMM in its annual State of the Market report. ERCOT staff, at the Commission's request, provided an estimate of the cost of implementation of RTC in a letter to the commission on September 5, 2013.[2] At that time, ERCOT estimated that the cost of RTC implementation would be approximately $42.5 million, and would require 3-5 years for development and testing. The potential benefits to the ERCOT market of RTC, however, had never been estimated and quantified.

While pricing of marginal losses was considered at the outset of the ERCOT competitive market and has been implemented in several other Regional Transmission Organizations, the costs and benefits of implementation of marginal losses have never been studied for the ERCOT market.

At the open meeting of August 26, 2017, the Commission directed ERCOT staff to develop a study of the benefits of implementing RTC and marginal losses in the ERCOT market. The IMM joined the project, focusing on the potential savings in production costs and congestion costs with RTC implementation, while ERCOT focused on the operational benefits of RTC and the potential benefits of marginal losses. The results of both studies were filed in this project on June 29, 2018.

There were several other recommendations included in the Hogan-Pope paper, including the exclusion of capacity due to Reliability Unit Commitment (RUC) deployment from online reserve capacity used in the calculation of the Operating Reserve Demand Curve (ORDC) price adder, adjustment of the Loss of Load Probability (LOLP) used in the

[1] William W. Hogan and Susan L. Pope, *Priorities for the Evolution of an Energy-Only Market Design in ERCOT* (May 9, 2017).
[2] *ERCOT's Impact Assessment of Real-Time Energy and Ancillary Services Co-optimization*, Project No. 40000, September 5, 2013.

calculation of the ORDC price adder, and modifying rules governing the pricing of resources committed through the RUC mechanism to mitigate the impact of RUC deployments on locational marginal prices. In comments submitted regarding the Hogan-Pope paper, several parties advocated that the Commission examine barriers to the participation of demand response in the energy and ancillary services markets, to determine whether those barriers could be reduced or eliminated through Commission rule changes or policy directives.

The Commission directed ERCOT to proceed with the proposal to exclude RUC capacity from the ORDC calculation at the March 8, 2018 open meeting, and the proposal was implemented by approval by the ERCOT Board of Directors of Other Binding Document Revision Request (OBDRR) 002 at the April 10, 2018 Board of Directors meeting.

The proposals to adjust the LOLP used in the ORDC calculation and to consider changes to RUC pricing rules were deferred by the Commission until after the 2018 summer peak demand season. Those proposals may appropriately be considered in Project No. 48551, following evaluation of the performance of the market this summer.

The examination of barriers to participation by demand response in the energy and ancillary services market was, by the Commission's direction at its October 26, 2017 open meeting, taken up in a pre-existing project: Project No. 41061, *Rulemaking Regarding Demand Response in the Electric Reliability Council of Texas (ERCOT) Market*. A Request for Comment was published on December 5, 2017, and a number of parties filed comments on January 19, 2018. No further action has been taken in this project since that date.

Results of the ERCOT and IMM Studies

a. Real-Time Co-optimization

According to the ERCOT report, co-optimization would yield substantial operational benefits. Among these are "...more timely procurement of [ancillary services] when necessary, more effective congestion management, a reduction in manual actions by operators, and an improved management of Resource-specific capabilities in assigning and deploying [ancillary services]."[3] Co-optimization also would lead to some reduction in Reliability Unit Commitment (RUC) deployments, and would virtually eliminate the need for Supplemental Ancillary Services Markets (SASMs), while increasing liquidity in the day-ahead ancillary services market.

Currently, ancillary services (AS) are procured in the day-ahead market based on forecasts of demand for and supply of electricity from various resource types. If system conditions change in real time, or if procured AS cannot be delivered for any reason, ERCOT conducts a SASM to procure additional AS or to replace undeliverable AS. Determining the

[3] *Study of the Operational Improvements and Other Benefits Association with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services* (ERCOT Report). ERCOT, June 29, 2018, at 3. (Attached hereto as Attachment C).

need for additional AS and setting up and running the SASM are time-consuming manual processes, and the reliability of the grid may be jeopardized in the interval between the identification of a need for additional AS and the procurement of that additional AS in the SASM. Because RTC can automatically assign AS to any available resource within five minutes, RTC would result in more timely procurement of additional AS when needed, and would free ERCOT operators from the time-consuming tasks of monitoring the need for additional AS and procuring additional AS through the SASM mechanism.

When transmission congestion develops on the ERCOT grid and no committed Resource with sufficient capacity and in the correct location to resolve the constraint exists, ERCOT may use a Reliability Unit Commitment (RUC) instruction to compel an uncommitted Resource to provide energy to relieve the congestion and ensure grid reliability. While sometimes necessary, this out-of-market action by ERCOT may have adverse impacts on price formation in the energy-only market, and it is therefore desirable to limit the number of RUC deployments as much as possible. Because RTC would allow Resources assigned with assigned AS responsibility to be re-assigned to provide energy to resolve transmission constraints, it may reduce the number of RUC commitments needed. ERCOT staff studied 165 RUC cases from 2016 and found that in nine of those cases, RTC would have completely eliminated the need for a RUC deployment. In an additional 27 cases, the decision to issue a RUC instruction could be deferred, and in some of these cases, a RUC instruction may not have been needed. In 103 other cases, the capacity required from RUC-committed resources would have been reduced if RTC had been implemented.

As noted above, SASMs are used by ERCOT to procure additional AS when required whether because of changing market conditions or because AS procured in the day-ahead market is unavailable or undeliverable. According to the ERCOT Report, prices for AS are generally much higher than the prices for AS in the day-ahead market; in ERCOT's analysis by an average of $100/MW. Because SASMs would be virtually eliminated under RTC, significant cost savings in prices paid for AS may be realized. The elimination of SASMs also would have the effect of reducing risk to generation resource owners who participate in the day-ahead AS market, particularly to smaller market participants with fewer opportunities to shift AS responsibilities among Resources in their fleet, thus potentially increasing participation in the day-ahead market.

The IMM study,[4] using actual bids and resource commitments from 2017, constructed a computer simulation of the performance of the ERCOT market with RTC in place. A second simulation of the same time period was conducted by ERCOT staff using a different computer model as a reasonableness check – the two models were found to produce very similar results. The market outcomes from the IMM simulation were then compared to actual results for 2017 to produce an estimate of the benefits of RTC implementation.

The IMM study showed significant cost savings on a number of metrics of market performance, summarized in the following table:

[4] *Simulation of Real-Time Co-Optimization of Energy and Ancillary Services for Operating Year 2017.* Stephen Reedy, Potomac Economics, June 29, 2018. (IMM Report). (Attached hereto as Attachment D).

Metric	$M Savings/year
Production Costs	11.6
Reduced RegUp, Reduced Overloading of Constraints	4.3
System Congestion Costs	257
Ancillary Service Costs	155
Energy Costs	1,600

The IMM notes in its description of the study that, due to some assumptions made in the model, actual savings may be even greater than estimated in the simulation.

b. Marginal Losses in SCED

Currently, the cost of energy lost as electricity flows through transmission lines from the point of generation to the point of consumption is recovered on a system-wide average basis: the total cost of transmission losses is charged to load-serving entities (LSEs) based on each LSE's share of total system load. The marginal losses proposal instead would incorporate the cost of transmission losses into the locational marginal price paid to generators based on the distance of each generator from the theoretical center of load, or reference bus – the further the generator from the reference bus, the greater the reduction in the LMP paid to that generator.

ERCOT staff conducted a study, using the same methodology and computer software used in the regional transmission planning process, to estimate the benefits of implementing marginal losses in ERCOT's Security Constrained Economic Dispatch (SCED). The analysis incorporated system changes anticipated by 2020, and estimated production costs, generator revenues and consumer costs using three different assumptions regarding natural gas costs.

In the study's base case scenario for natural gas prices, implementation of marginal losses might result, system-wide, in production cost savings of $11.4 million annually, a reduction in generator revenues of $212.5 million annually, and a reduction in consumer costs of $135 million annually. Because the marginal losses proposal recovers transmission losses based on the geographic location of Generation Resources, the impact of marginal losses is quite different for the four main ERCOT load zones. Generator revenues, for example, decrease in the North and West load zones, but actually increase in the Houston and South load zones.

ERCOT notes that the cost savings projected by the model may be mitigated by increases in make-whole payments and start-up costs. The model also does not consider the impact on costs if the revenue reduction to Generation Resources in the North and West zones leads to accelerated retirements of units in those zones.

The IMM did not study the costs or benefits of marginal losses implementation.

Attachment A

Project No. 48539 – *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch*

Proposed Questions for Stakeholder Comment

PUBLIC UTILITY COMMISSION OF TEXAS
PUBLIC NOTICE OF REQUEST FOR COMMENTS

PUC PROJECT NO. 48539

REVIEW OF THE INCLUSION OF MARGINAL LOSSES IN SECURITY-CONSTRAINED ECONOMIC DISPATCH

The staff of the Public Utility Commission of Texas (commission) requests comments on questions regarding Project No. 48539, *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch.* Written comments may be filed by submitting 16 copies of such comments to the commission's Filing Clerk, Public Utility Commission of Texas, 1701 North Congress Avenue, P.O. Box 13326, Austin, Texas 78711-3326 within 45 days of the date of publication of this notice. Comments longer than ten (10) pages should also be filed in digital native format via the commission's electronic filer at: http://interchange.puc.texas.gov/filer. Reply comments are not requested at this time. All responses should reference Project Number 48539.

Questions concerning this notice should be referred to Mark Bryant at (512) 936-7279 or mark.bryant@puc.texas.gov. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission through Relay Texas by dialing 7-1-1.

1. Please describe the benefits of implementing marginal losses over the long term.
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.

3. What are the effects of marginal losses on reliability?

4. What effects, if any, would the implementation of marginal losses have on grid reliability in regions of the ERCOT grid where asynchronous generation is more prevalent?

5. How would a decision to implement marginal losses affect investment in new generation resources in ERCOT over the next five years and the makeup of the generation fleet in ERCOT? Over the next 10 years and beyond?

6. Please explain the nature and the extent of changes to market participants' settlement-related systems that are required to implement marginal losses. Are other systems affected?

7. Assuming implementation of marginal losses, what are the key issues related to determining the appropriate treatment and allocation of the marginal loss surplus?

8. The ERCOT study of marginal losses simulated one year. How might cumulative multi-year impacts of implementation be different, if at all?

9. How would implementation of marginal losses change the transmission planning process and transmission build-out?

10. What costs would be incurred by market participants if marginal losses were included in Security-Constrained Economic Dispatch 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.

11. What effects, if any, would marginal losses have on grid hardening and resilience? What advantages and disadvantages would there be to incentivizing generation to locate close to load, in an emergency event, and with respect to market restart?

12. What effects, if any, would the implementation of marginal losses have on the CRR market?

13. How could the Commission implement marginal losses in a way that mitigates any deleterious effects on CRRs?

14. Does your assessment of the incorporation of marginal losses change based on the timeline of implementation?

15. What operational changes do you foresee that are not considered in the studies?

16. What are the effects of implementing both RTC and marginal losses on reliability and price formation? Are there any synergies that may result from contemporaneous adoption of both RTC and marginal losses?

17. What are the effects to ratepayers and the retail market on the implementation of RTC and marginal losses?

ISSUED IN AUSTIN, TEXAS ON THE _____ DAY OF ______ 2018 BY THE PUBLIC UTILITY COMMISSION OF TEXAS ADRIANA A. GONZALES

Attachment B

Project No. 48540 – *Review of Real-Time Co-optimization in the ERCOT Market*

Proposed Questions for Stakeholder Comment

PUBLIC UTILITY COMMISSION OF TEXAS
PUBLIC NOTICE OF REQUEST FOR COMMENTS

PUC PROJECT NO. 48540

REVIEW OF REAL-TIME CO-OPTIMIZATION IN THE ERCOT MARKET

The staff of the Public Utility Commission of Texas (commission) requests comments on questions regarding Project No. 48540, *Review of Real-Time Co-optimization in the ERCOT Market.* Written comments may be filed by submitting 16 copies of such comments to the commission's Filing Clerk, Public Utility Commission of Texas, 1701 North Congress Avenue, P.O. Box 13326, Austin, Texas 78711-3326 within 45 days of the date of publication of this notice. Comments longer than ten (10) pages should also be filed in digital native format via the commission's electronic filer at: http://interchange.puc.texas.gov/filer. Reply comments are not requested at this time. All responses should reference Project Number 48540.

Questions concerning this notice should be referred to Mark Bryant at (512) 936-7279 or mark.bryant@puc.texas.gov. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission through Relay Texas by dialing 7-1-1.

1. Please describe the benefits of implementing real-time co-optimization of energy and ancillary services (RTC) over the long-term.
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.
3. What are the effects of RTC on reliability?
4. How would a decision to implement RTC affect investment in new generation resources in ERCOT over the next five years? Over the next 10 years and beyond?

5. Please explain the nature and extent of changes to market participants' settlement-related systems that are required to implement RTC. Are other systems affected?

6. What is the appropriate funding mechanism for the ERCOT implementation costs associated with RTC? How should these costs be recovered?

7. How might RTC change the ancillary services market?

8. What effects, if any, would the implementation of RTC have on the Congestion Revenue Rights (CRR) market?

9. What are the effects of implementing both RTC and marginal losses on reliability and price formation? Are there any synergies that may result from contemporaneous adoption of both RTC and marginal losses?

ISSUED IN AUSTIN, TEXAS ON THE _____ DAY OF ______ 2018 BY THE PUBLIC UTILITY COMMISSION OF TEXAS ADRIANA A. GONZALES

Attachment C

Study of the Operational Improvements and Other Benefits Association with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services.

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

ERCOT, June 29, 2018

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June 29, 2018

Public Utility Commission of Texas
Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin
1701 N. Congress Ave.
Austin, Texas 78701

Re: *PUC Project No. 47199 – Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*

Dear Chairman and Commissioners:

As requested by the Commission at its October 27, 2017 open meeting, Electric Reliability Council of Texas, Inc. (ERCOT) hereby submits its *Study of the Operational Improvements and Other Benefits Associated with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services* (Attachment A) and its *Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch* (Attachment B). ERCOT also notes that the Independent Market Monitor (IMM) for the ERCOT region, Potomac Economics, is today filing its assessment of the benefits of co-optimization with respect to Security Constraint Economic Dispatch in the ERCOT market.

ERCOT appreciates the opportunity to provide this information to the Commission and would be pleased to provide any additional information or analysis the Commission may request.

Respectfully,

Nathan Bigbee
Assistant General Counsel
(512) 225-7093
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ercot

Study of the Operational Improvements and Other Benefits Associated with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services

June 29, 2018

1. Introduction

Electric Reliability Council of Texas, Inc. (ERCOT) provides this report in response to the October 27, 2017, Open Meeting discussion directing ERCOT and the Independent Market Monitor of Texas to study the expected benefits of the potential implementation of Real-Time Co-optimization (RTC) of energy and Ancillary Services (AS). This report addresses the implications of RTC on the actions of ERCOT's operators to manage system reliability and provides a quantitative analysis of the effects of RTC on historical Reliability Unit Commitment (RUC) and Supplemental Ancillary Service Market (SASM) activity. ERCOT has also provided support to the Independent Market Monitor (IMM) in its historical analysis of the impact of RTC on Security-Constrained Economic Dispatch (SCED), which is being submitted separately.

ERCOT's analysis has yielded several key findings. First, ERCOT anticipates significant operational benefits from the implementation of RTC, including more timely procurement of additional AS when necessary, more effective congestion management, a reduction in manual actions by operators, and an improved management of Resource-specific capabilities in assigning and deploying AS. Regarding RUC activity, a study of 165 historical RUC cases from 2016 indicates that co-optimization would have eliminated Resource commitments in at least 9 of the cases. Finally, ERCOT has executed 391 SASMs covering more than 2,200 operating hours since the beginning of the nodal market at clearing prices averaging approximately $100/MWh more than the corresponding Day-Ahead Market (DAM) price for the same operating day, hour, and AS product. The number of MW procured in these SASMs, when priced at the $100/MW premium, is a cost difference of approximately $11 million. RTC would eliminate the need for these SASMs. Also related to SASMs, the ability of Market Participants to buy back their AS in Real-Time under RTC and reduce their risk of a Day-Ahead AS obligation due to a SASM would likely increase the liquidity of the Day-Ahead AS market.

2. Operational Benefits of Co-optimization

Under the current market design, ERCOT procures required quantities of AS in the DAM to ensure grid reliability in Real-Time. AS procured in the DAM acts as insurance for system events ranging from forecast error to unit trips. ERCOT operators rely on SASMs to replace AS responsibilities that are declared infeasible due to congestion or that the responsible Qualified Scheduling Entity (QSE) fails to provide. The approximate two-hour period required to announce a SASM, allow Market Participants to update their offers, execute the SASM, post the results, and allow Market Participants to update their Current Operating Plans (COPs) reflecting awards, effectively prevents ERCOT from replacing the AS responsibility within the two hours following identification of the insufficiency, potentially extending AS shortages during that period. ERCOT operators have, in fact, experienced these shortages while awaiting procurement. By contrast, under RTC, SCED would dynamically assign AS responsibilities during its next execution and replace that responsibility. RTC thus resolves the reliability concerns associated with the delay in procuring infeasible or insufficient AS.

RTC would also improve ERCOT's ability to manage changing AS needs associated with the evolving Resource mix in the ERCOT region. As ERCOT's Resource mix continues to change, identifying risks associated with forecasted demand, wind, and solar will be key to ensuring reliable grid operations. ERCOT expects these changes will also result in more efficient and nimble unit commitments by Market Participants. The excess headroom capacity that the grid has enjoyed in Real-Time has often covered the historical risk associated with infeasible and insufficient AS and AS that QSEs fail to provide; but a decrease in this capacity could result in lower margins of error in both identifying AS requirements as well as replacing AS responsibilities. RTC would allow ERCOT to dynamically adjust AS quantities in Real-Time as uncertainties associated with demand, wind power, and solar power change. Without RTC, the changes to ERCOT's Resource mix would require ERCOT to be more conservative in estimating the needed AS quantities to ensure reliability, which may add costs to the market.[1]

The implementation of RTC would also allow ERCOT to more efficiently resolve congestion on the transmission system. RTC would enable SCED to recognize and act on the preference for having energy, as opposed to AS, at a given location on the transmission system, including during periods of non-scarcity. While locational pricing will indicate this preference under the current design, individual Market Participants cannot always respond to this preference in the near-term, especially those with small Resource portfolios. Additionally, the ability to act on this preference automatically and immediately will reduce the volatility of dispatch of Resources across the system.

Implementing RTC would also allow ERCOT operators to focus on other reliability issues. Significant operator attention is currently allocated to various activities associated with monitoring and addressing system AS needs. These activities include (1) identifying the conditions that will trigger the need to deploy AS and release additional capacity for economic dispatch, (2) tracking the ability of individual Resources to meet scheduled AS responsibilities, and (3) detecting cases in which the provision of AS is infeasible due to congestion on the transmission system. These manual activities would be automatically performed with the implementation of RTC and would be done without adversely impacting market pricing, which is a risk when using manual processes. Automating these activities through RTC would allow ERCOT operators to refocus their attention on various other concerns arising on the grid during Real-Time operations. RTC would also result in more consistent, predictable outcomes for Market Participants, due to the replacing current manual reliability actions with a market solution, and would allow Market Participants to better prepare for and respond to conditions on the grid.

Finally, the implementation of RTC would result in improved management of Resource-specific capabilities in assigning and deploying AS through continuous Real-Time adjustments of individual AS responsibilities. Today, the scenarios in which this does not occur can lead to degradation of the services. For example, in transitioning from one operating hour to another, Resources may take multiple SCED intervals to adjust to their updated AS responsibilities, which means the full amount of AS they are obligated to provide may not necessarily be available for deployment during this transition period. Similar concerns arise with the deployment of Regulation Service at the portfolio level where the system is not designed to consider individual Resource capabilities and the total

[1] The quantities of AS that are procured in the DAM are typically determined between 1 month and 13 months ahead of the operating period during which they will be in effect. With these values being determined far in advance, the amount of AS procured may not necessarily truly reflect the needs in Real-Time. The methodology for determining the minimum amount of AS can be found at
http://www.ercot.com/content/wcm/key_documents_lists/89135/ERCOT_Methodologies_for_Determining_Minimum_Ancillary_Service_Requirements.zip.

expected output of the Resource cannot be fully attained. The continuous adjustments enabled through RTC would increase the likelihood that procured AS would be fully provided.

In a related manner, implementation of RTC would allow ERCOT to better utilize limited-duration Resources such as batteries and Controllable Load Resources. RTC would allow ERCOT to use system-wide information updated every five minutes to identify the optimal AS responsibility quantities for each Resource while considering and respecting the Resource's limits and status. This will remove unnecessary barriers to participation in the AS markets.

3. Reliability Unit Commitment (RUC) Analysis

3.1. Impact of RTC on the Need for RUC Commitments

If RTC were to be implemented in the ERCOT market, ERCOT presumes that the optimization engine for the RUC process would also be modified to co-optimize energy and AS. As a result, the RUC engine would have improved capability to resolve projected congestion on the transmission system with Resources that are already committed by their Qualified Scheduling Entity (QSE) to be on-line. Co-optimization would allow all on-line capacity from Resources, including capacity that is currently reserved by Market Participants to provide AS, to be used in the most effective way to meet all of the constraints of the system: balancing power needs, meeting AS requirements, and managing transmission constraints. This would lead to an overall reduction in the need for ERCOT to instruct additional Resources on-line.

Currently, each QSE decides which of its Resources will be responsible for satisfying the QSE's AS obligation in Real-Time. These obligations can result from DAM awards, SASM awards, self-schedules of AS, or trades with other Market Participants. The decisions are communicated to ERCOT through Resource COPs, and the COPs are used as inputs to the RUC optimization engine. The RUC optimization engine is unable to modify the AS assignments of Resources, even if the reserved capacity could help resolve transmission congestion and avoid out-of-market Resource commitments. Incorporating the co-optimization of energy and AS in the RUC process would provide the RUC optimization engine the flexibility to determine the most efficient way to make use of the Resources projected to be on-line and available.

Two conditions need to be met in order for co-optimization to reduce the need for RUC instructions by ERCOT. First, at least one Resource with an AS responsibility must be located at a point in the system where it could help manage transmission congestion that cannot be resolved through the re-dispatch of other on-line Resources. Second, there must be other Resources elsewhere in the system that are both qualified to provide the service and not currently needed to help resolve other constraints on the system. In cases where these conditions are not met, co-optimization will not affect the need for RUC instructions. In cases where these conditions are met, the magnitude of the benefit will depend on the amount of capacity being reserved on the Resource to provide AS, the sensitivity of the Resource in helping to resolve the transmission congestion, and the magnitude of the projected overloading of the transmission equipment prior to rearranging the AS responsibilities.

3.2. Impact of RTC on Historical RUC Activity

ERCOT performed an analysis to quantify the effect of co-optimization on historical RUC cases. In this analysis, 165 historical RUC cases from 2016, during which a RUC instruction occurred, were executed with the inputs modified to determine whether there was a reduction in commitment recommendations from the RUC engine if it were able to co-optimize energy and AS. These 165 cases account for all cases in 2016 where the RUC engine recommended the commitment of the Resource that was instructed on-line by ERCOT. In the cases where a RUC instruction was not recommended by the RUC engine (e.g., a Verbal Dispatch Instruction (VDI) or a manual selection by the operator), a change to the commitment recommendation from the RUC engine would not clearly indicate a change in the decision to commit the Resource. It should also be noted that not all recommendations from the RUC engine are accepted and issued as instructions by ERCOT. For example, a recommendation is typically deferred if there is ample time to commit the Resource during a later RUC study.

To simulate the effects of co-optimization for this study, ERCOT modified the RUC cases to remove all AS responsibilities from on-line Generation Resources in order to provide the optimization engine flexibility to resolve transmission constraints with all on-line capacity. After executing the RUC optimization with these modified cases, the results were analyzed to determine whether there was still sufficient qualified on-line capacity available to which the AS responsibility could be reallocated. If sufficient capacity was identified in the solution, the analysis concluded that a RUC engine with co-optimization would have reached that solution while still honoring on-line AS requirements.[2] This approach is conservative and will not identify all cases in which co-optimization would have reduced the need for a RUC instruction. Even in a case where the solution did not have sufficient on-line capacity to meet the AS requirements, it is possible that a co-optimized solution could have found an alternative solution meeting both transmission and AS requirements by shifting dispatch from AS-qualified capacity elsewhere in the system to unused capacity on Resources not qualified to provide AS.

[2] RUC with co-optimization would not ensure that there is a specific amount of on-line capacity providing Non-Spinning Reserve but would instead ensure that there is a sufficient combination of on-line and off-line capacity available. For this reason, this analysis did not require that the Non-Spinning Reserve be provided by on-line Resources.

The results from this analysis can be found in the following table:

Result	Expected Co-optimization Impact	Number of Cases
All originally committed Resources would still be recommended.	The RUC-committed Resource would still have been committed.	109
At least one originally committed Resource was no longer recommended, and the decision to commit one or more of the Resources in the new set of recommendations could not be deferred.	A different Resource would have been committed instead of the RUC-committed Resource.	20
At least one originally committed Resource was no longer recommended, and the decision to commit all Resources in the new set of recommendations could be deferred.	The RUC-committed Resource would not have been committed, and the decision to commit an alternative Resource would have been deferred. No Resources would have been RUC-committed in some of these cases.	27
The committed Resources were no longer recommended, and no alternative Resources were recommended. There was sufficient remaining capacity for AS.	No Resource would have been RUC-committed.	9
Total		165

Table 1. 2016 RUC re-run results comparing recommended resources

These results show that, in 109 of the 165 cases, removing AS responsibilities did not change the Resource commitment recommendations, suggesting that RTC would not likely have impacted the decision to commit the Resource. There are two likely reasons that the commitment recommendations did not change in these cases: either the case had few or no Resources that were carrying AS and that also had the ability to reduce flow on the constrained element, or the initial constraint violations were so large that the capacity reserved for AS would be insufficient to resolve the constraint.

In 47 of the 165 cases, the analysis recommended commitment of a new Resource in place of one or more originally recommended Resources. In 20 of these 47 cases, the recommendation could not be deferred due to Resources' startup times. In these cases it is likely that co-optimization would not have impacted the decision to commit a Resource. However, in 27 of the 47 cases, the decision to commit all of the recommended Resources could be deferred for at least one hour, indicating that the operator could wait until closer to Real-Time to see if system conditions changed or there were self-commitments that obviated the need for a RUC instruction. It is likely that in some of these 27 cases, co-optimization would have eliminated the need for the RUC instruction.

In the 9 remaining cases, removing the AS responsibilities from the RUC cases resulted in the elimination of all RUC recommendations. In each of these cases, there was sufficient qualified capacity remaining to fulfill AS requirements, indicating that co-optimization would have eliminated the need for the RUC instruction. Thus, in total, ERCOT's analysis suggests that RTC would have eliminated the need for RUC instructions in at least 9 of the 165 cases studied; but, as noted above, it might also have eliminated the need for RUC instructions in some of the 27 cases in which the decision to commit could be deferred.

As part of this analysis, ERCOT also considered the impact of RTC on the total amount of capacity recommended for commitment by the RUC engine. For example, if co-optimization allowed a 50 MW HSL Resource needed for one hour to replace a 100 MW Resource needed for two hours, the out-of-market capacity would decrease from 200 MW-hours to 50 MW-hours (i.e., a reduction of 150 MW-hours).

The results from this additional analysis are shown in the following two tables:

Result	Number of Cases
Cases with fewer recommended HSL MW-hours	103
Cases with equal recommended HSL MW-hours	32
Cases with more recommended HSL MW-hours	30
Total	165

Table 2. 2016 RUC re-run results comparing recommended HSL MW-hours

Result	Number of Cases
Cases with fewer recommended LSL MW-hours	103
Cases with equal recommended LSL MW-hours	33
Cases with more recommended LSL MW-hours	29
Total	165

Table 3. 2016 RUC re-run results comparing recommended LSL MW-hours

The above tables illustrate that, out of 165 RUC cases studied, 103 of the cases (62%) recommended fewer HSL MW-hours in total after releasing AS responsibilities, 32 of the cases (19%) recommended the same number of HSL MW-hours, indicating that co-optimization had no effect on the need to issue RUC commitments, and 30 of the cases (18%) had more HSL MW-hours recommended. The impact to LSL MW-hour recommendations is nearly the same. In the cases where RUC recommended more HSL or LSL MW-hours, the RUC engine was able to resolve more transmission violations with the individual Resource AS responsibilities relaxed. While resulting in more MW-hours, this result illustrates that co-optimization would increase the reliability of the system by providing the dispatch engine more options to resolve transmission constraints. In total, the analysis reduced the total HSL MW-hours recommended in the 165 cases from approximately 712 GW-hours to 577 GW-hours, a reduction of 19%, and reduced the total LSL MW-hours from approximately 207 GW-hours to 164 GW-hours, a reduction of 21%.

An example illustrates how co-optimization can eliminate the need for a RUC commitment. On May 31, 2016, ERCOT issued a RUC instruction to commit Capitol Cogen, a Combined-Cycle Generation Resource in the Houston area, for three hours to relieve congestion on the Singleton-Zenith lines that carry power into Houston. In this particular case, co-optimization would have allowed RUC to access approximately 1,500 MW of capacity that could have helped relieve the constraint, but was reserved for AS. The Resources with this capacity had varying sensitivities to the projected congestion, but in aggregate could have provided up to 136 MW of relief on the congested transmission line and removed the need to commit Capitol Cogen. In fact, there was one on-line Resource alone that had 120 MW of capacity reserved for AS that could have otherwise resolved the transmission constraint on its own, without needing to reassign AS from any of the other Resources in the system.

This analysis only studied the RUC commitments that occurred in 2016, and the number and impact of RUC instructions can vary and are hard to predict. While this analysis is only an indication of the impact of co-optimization on future RUC instructions, the results show that co-optimization would have reduced the need for RUC instructions by at least 9 of the 165 cases studied. To the extent that changes in market conditions or system complexity and uncertainty increase the need for ERCOT to issue RUC instructions, co-optimization would likely further mitigate the impact of those commitments.

4. Impacts of Co-optimization on the Supplementary Ancillary Service Market

SASMs are one mechanism ERCOT uses to reassign AS obligations when one or more QSEs are unable to provide their AS obligation in Real-Time. SASMs are often less liquid than the DAM, resulting in clearing prices that are significantly higher than DAM and not reflective of either the DAM or RTM conditions. With RTC, the RUC process would ensure that sufficient AS-qualified capacity is available and AS responsibilities would be dynamically assigned to the optimal set of on-line qualified Resources in Real-Time by RTC. As a result, the liquidity for reassigning AS responsibility would be increased in Real-Time. ERCOT expects that SASM would not be necessary with RTC, particularly for the cases in which a SASM is being used to reassign AS for a QSE that is unable to meet its AS obligations.

Clearing prices are higher in SASMs than in the DAM for several reasons. First, SASMs typically have much less liquidity than the DAM, which is primarily attributable to the infrequent and unpredictable nature of SASMs. Market Participants do not set aside capacity from DAM to offer into a SASM, and capacity that was cleared in the DAM is also no longer available in a SASM. Liquidity is also limited because Market Participants may not have the fuel arrangements necessary to provide AS. The second reason SASM clearing prices are higher is that offer prices are higher. SASM offers are generally higher than DAM offers because the more economic AS capacity already cleared in the DAM and because there is no make-whole guarantee, so QSEs have to include any applicable startup and minimum generation costs in their SASM offer without knowing what volume of AS they will be awarded. All these factors tend to result in higher clearing prices, potentially significantly higher, in a SASM, relative to the DAM.

These higher prices can result in disproportionate impacts on QSEs with fewer Resources in their portfolios. If a QSE fails to meet its AS obligation, it is required to pay a financial penalty, which may be based on the SASM clearing price. A QSE with a larger fleet is more insulated from the risk of paying this penalty as it is more likely to be able to shift the AS responsibility to another Resource within its portfolio. This asymmetry in risk for Market Participants is present in both energy and AS products, but is of greater significance in the AS market because the financial penalties are often higher for AS than for energy. RTC would reduce this asymmetry and would create an opportunity for increased participation in the DAM AS market.

To quantify the risk of high penalties due to failing to meet an AS obligation, ERCOT studied historical SASM and DAM AS prices from Nodal Go-Live through January 2018 to determine the price spread between the two markets. During this period, ERCOT executed 391 SASMs to replace approximately 130,000 MWh of AS covering more than 2,200 operating hours. Table 4 below contains statistics for the differences between each SASM clearing price and the DAM clearing price for the same operating day, delivery hour, and AS product. The average difference is $99.78/MWh, which is a substantial risk for products that normally clear between $1/MWh and $20/MWh in the DAM. The total difference in cost of these SASMs was approximately $11 million. RTC would eliminate SASMs and their associated risk and would also likely increase the liquidity of the DAM AS market as a consequence.

Statistic	SASM Price Minus the DAM Price for the Same Hour and AS Type
Min	-$491.14
10%	-$8.40
25%	-$2.23
Median	$2.05
75%	$15.90
90%	$253.45
Max	$6,969.49
Mean	$99.78

Table 4. Statistics on differences between SASM prices vs. corresponding DAM prices (Dec. 2010 - Jan. 2018). Positive values indicate SASM price cleared higher than the corresponding DAM price for the same operating day, hour, and AS product.

5. Conclusions

ERCOT's analysis of the impacts of RTC on operations and on RUC and SASM procurement identified a number of potential benefits.

The study of historical RUC cases suggests that co-optimization would have reduced the need for a RUC instruction in at least 9 of the 165 cases studied, due to the optimization engine having the flexibility to use all of the on-line capacity to meet the energy and AS requirements of the system.

ERCOT's analysis of 391 historical SASMs found that SASM clearing prices averaged nearly $100/MW higher than the corresponding DAM price for the same operating day, hour, and AS product. The number of MW procured in the 391 historical SASMs priced at the approximate $100/MW premium is a cost difference of approximately $11 million. RTC would eliminate the need for these SASMs and the associated risk. This, combined with the ability of Market Participants to buy back their AS obligation in Real-Time through the clearing of AS awards under RTC, will increase the liquidity of the DAM AS market.

ERCOT believes that implementation of RTC would provide significant operational and reliability benefits as the complexities of managing a changing resource mix continue to grow through more timely procurement of AS when additional AS is required or Resources are unable to provide those services, more effective congestion management, and a reduction in manual actions by operators.

Finally, RTC will also provide a framework that will provide a mechanism for improved management of Resource-specific capabilities in assigning and deploying AS.

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

June 29, 2018

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.

Attachment D

Simulation of Real-Time Co-Optimization of Energy and Ancillary Services for Operating Year 2017.

Stephen Reedy, Potomac Economics, June 29, 2018.

Potomac Economics, Ltd.
7620 Metro Center Drive
Austin, Texas 78744

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June 29, 2018

Public Utility Commission of Texas
Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin
1701 N. Congress Ave.
Austin, Texas 78701

Re: *PUC Project No. 47199 — Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*

Dear Chairman and Commissioners:

As requested by the Commission at its October 27, 2017 open meeting, Potomac Economics, the Independent Market Monitor (IMM) for ERCOT, hereby submits its *Simulation of Real-Time Co-Optimization of Energy and Ancillary Services for Operating Year 2017*, to be filed in Project No. 47199, *Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*.

The IMM appreciates the opportunity to provide this information and would be pleased to provide any additional information or analysis the Commission may request.

Sincerely,

Ralph J. Daigneault
Counsel, Potomac Economics
(512) 225-7148
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POTOMAC ECONOMICS

Simulation of Real-Time Co-Optimization of Energy and Ancillary Services for Operating Year 2017

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POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

June 29, 2018

1. Introduction

Potomac Economics, the Independent Market Monitor ("IMM") for the wholesale market in the Electric Reliability Council of Texas, Inc. ("ERCOT") region, provides this report in response to the discussion at the open meeting of the Public Utility Commission of Texas ("Commission") on October 26, 2017, directing ERCOT and the IMM to assess the expected benefits of the potential implementation of Real-Time Co-optimization ("RTC") of energy and Ancillary Services ("AS") in the ERCOT wholesale electricity market. In this study, the IMM used the actual offers and commitment status of resources in ERCOT (along with other information not considered Protected Information under the ERCOT Protocols) for operating year 2017 to simulate the effect RTC would have had on dispatch, prices, costs, and system conditions under the assumption that market participant behavior remained unchanged.

Key findings from the simulation include:

- A significant reduction in production costs (as measured by offer curves) to serve load ($11.6M);
- A significant improvement in system reliability due to reduced overloading of network constraints and reduced use of Regulation Up Service ($4.3M);
- A significant reduction in system congestion costs ($257M);
- A significant reduction in AS costs ($155M): and
- A significant reduction in energy costs ($1.6B or approximately $4/MWh).

2. Simulation Method and Assumptions

The IMM simulated RTC for operating year 2017 using open source tools (python, CVXOPT, and MIPCL-PY) and a combination of published and publishable (i.e., information not considered Protected Information under the ERCOT Protocols) data including, but not limited to, 60-Day Security Constrained Economic Dispatch ("SCED") Disclosure Reports, binding constraints, and shift factors to model changes in market results if RTC had been used to allocate reserve capacity. The simulation program code, data, and use instructions are published at http://www.ercot.com/mktinfo/rtm/immtool.

The IMM used the following assumptions and methods in its simulation:

- Offers remained constant (SCED step 2 offers as published in the 60-Day report);
- Commitment remained consistent (the simulation used the status of each resource as published in the 60-Day report);
- If a resource had provided a particular AS in the trailing twelve months, it was considered qualified to provide that service in real time with an assumed offer of $0/MWh;
- AS provided by load and offline resources were held constant and not co-optimized;
- Regulation Down Service awards were held constant and not co-optimized;
- Each interval was simulated individually, with no dependence upon the results of previous interval simulations;
- If a resource was awarded Responsive Reserve Service (RRS), any Non-Frequency Responsive Capacity (NFRC) was subtracted from its high limit;
    - NFRC was determined as either the telemetered NFRC (if the resource was originally carrying RRS), or the highest value of High Sustainable Limit (HSL) – RRS – Regulation Up – High Ancillary Service Limit (HASL) recorded in the trailing twelve months);
- Only the 35,040 intervals that were previously published in the 60-Day reports were simulated and the results were extrapolated to the intervals that were not published;
- AS awards followed the requirements as outlined in *Ancillary Service Market Transactions in the Day-Ahead and Real-Time Adjustment Period* Business Practice Manual;
- Production costs, congestion, reliability, and energy prices were compared to simulations of the current real-time market (SCED) to reduce effects of possible data errors; and
- The results of the simulation using open source tools were compared to the results of a simulation run by ERCOT using similar assumptions performed using proprietary software (SAS). Of the 35,040 intervals simulated, 34,946 produced results that were

virtually indistinguishable[1] in both simulations; only those intervals are included in the results presented in the next section.

3. Simulation Results

3.1. Production Cost Savings

The main feature of RTC of energy and AS is the resulting movement of reserves away from low cost resources that can efficiently produce energy and towards higher cost resources. The amount of savings that energy producers would realize by having their reserves and energy co-optimized is an important metric in deciding whether RTC is worth the implementation costs. Although there is no granular public information regarding the production costs of each resource in ERCOT, all of the offers for 2017 have been published in the 60-Day reports. Assuming that resource offers are competitive and therefore reflective of its marginal costs, a resource's production cost is determined by its start-up offer, its minimum run offer, and the area under its offer curve (more precisely, the value of its offer curve integrated from the low limit to the dispatch level.) Because commitment decisions in this simulation remained unchanged from actual commitment decisions in operating year 2017, the start-up costs and the minimum runs costs are not affected by RTC and can be ignored. With the ability to move reserve capacity away from less costly resources and towards more expensive resources, however, the IMM estimates that the production costs for 2017 would have dropped by $11.6M with RTC.

Because the simulation assumed that commitment remained constant, this estimate of production costs savings is likely lower than what would be expected. Prices would be lowered by RTC leading to resources being less likely to commit, thus forgoing start-up costs and minimum run costs and further increasing the production cost savings. The IMM has made no attempt to quantify this effect.

1 "Virtually indistinguishable" intervals met the following three criteria: 1). SCED objective functions within $1000, 2) RTC objective functions within $1000, and 3) SCED system lambdas within $10.

3.2. Reliability Improvements

Two features of RTC of energy and AS that can improve reliability are:

1. The movement of reserves away from – and energy production to – locations that need more energy to reduce overloading of constraints; and
2. A more efficient use of ramping capability and non-frequency responsive capacity to reduce the reliance on Regulation Up Service during scarcity.

3.2.1. Network Overloading Reductions

Current market design will move energy production to prevent network constraints from exceeding their limit as long as the cost of doing so remains below a dollar amount that varies by voltage level (the shadow price cap). A monetary metric for the reliability improvement of reducing or eliminating constraint overloading is the amount of overload reduction multiplied by the shadow price cap for that constraint.

3.2.2. Reduced Reliance on Regulation Up Service

By more efficiently assigning RRS, and thus more efficiently deploying NFRC, as well as by more efficiently using the ramp capacity available in the system, RTC reduces the amount of Regulation Up Service used to serve energy via the Power Balance Penalty Factor mechanism.

3.2.3. Total Reliability Effect

The total effect on reliability for 2017 seen with RTC was an improvement of $4.3M.

3.3. Congestion Cost Reduction

The geographical movement of energy and reserves discussed above in Section 3.2.1 would also have reduced real-time congestion in a similar way to how it reduced network constraint overloading. The geographical movement of reserves and energy in the 2017 simulation of RTC reduced congestion costs, as measured by the shadow price of the constraint multiplied by the flow on the constraint, by $257M, a 26% reduction.

3.4. Ancillary Services (AS) Cost Reduction

Allowing AS to be provided from all of the available reserves in the system, rather than just those offered in the day-ahead market, significantly increased the supply of reserves and produced a significant reduction in the price of AS. Also, without the risk components inherent in offering products in the day-ahead market, the offer prices for reserves were $0/MWh.

To measure the reduction in AS costs, the IMM compared the day-ahead prices of Non Spin Reserve Service, Responsive Reserve Service, and Regulation Up Service and multiplied them by the quantities originally provided by online generation resources. The IMM then compared that amount to the prices generated by the RTC simulation multiplied by the same quantities. The increased supply and lowered offer prices in the simulation lowered the amount of money spent on AS by $155M.

Because the simulation assumed that commitment remained constant, this estimate of AS cost reduction is likely higher than expected outcomes. RTC is expected to lower prices leading to resources being less likely to commit, thus reducing the amount of reserve capacity online and offered into the market, ultimately reducing the amount of the price decrease. The IMM has made no attempt to quantify this effect.

3.5. Energy Cost Reduction

Energy prices were significantly reduced in the RTC simulation for the following reasons: 1) energy production was shifted away from higher cost units and toward lower cost units, 2) energy production was shifted geographically to relieve congestion, and 3) energy and reserves were shifted to improve use of units' NFRC and ramping capability. As a result, in a year with relatively few occurrences of scarcity pricing, scarcity pricing levels were eliminated and energy prices were reduced. The amount of price reduction, as measured by the average price paid by load (system lambda) multiplied by the total generation for each interval, was $1.6B, or approximately $4/MWh.

Because the simulation assumed that commitment remained constant, this estimate of energy price reduction is likely higher than would be expected. Prices would be lowered by RTC leading to resources being less likely to commit, thus reducing the amount of reserve capacity online and offered into the market, ultimately reducing the amount of the price decrease. The IMM has made no attempt to quantify this effect.

4. Conclusion and Recommendation

Substantial benefits can be achieved by implementing RTC of energy and AS. First, jointly optimizing all products in each interval allows AS responsibilities to be continually adjusted in response to changing market conditions. This is seen in the simulation for operating year 2017 in the substantial reduction in production costs, reliability improvements, and congestion, even under a set of conservation simulation assumptions. Second, RTC improves the accuracy of shortage pricing. Even in 2017, a year with high installed reserves, the simulation found that there were many intervals where the average load price was at a level which would imply scarcity. With RTC, however, the number of those intervals decreased significantly. In an energy only market that depends on scarcity pricing signals to provide incentive for proper levels of investment, it is important the scarcity pricing reflects actual scarcity rather than the inefficient assignment of reserve capacity.

The IMM has consistently and continually recommended implementation of RTC since the implementation of the nodal market.[2] ERCOT has estimated a total cost of $40M and a project duration of 4 to 5 years to implement RTC if the Commission decides to move forward with the implementation of RTC and after applicable Protocol changes have been approved by the ERCOT Board of Directors.[3] This simulation of RTC for operating year 2017, and in particular the projected production costs savings of $10M-$12M annually, provides quantitative evidence of the benefits and improved market efficiencies of RTC that more than justify the implementation costs. Therefore, we recommend the Commission and ERCOT move forward with implementation of RTC as expeditiously as possible.

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2 *See Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to SUBST R. §25 50.1*, Docket No. 31540, Direct Testimony of David B. Patton, Staff Ex. 1 at 23-28 (Nov. 10, 2005).

3 *Electric Reliability Council of Texas, Inc 's Progress Report Regarding Real-Time Co-optimization*, Project No. 41837, at 5-9.