Rewarding Flexibility: An Analysis of the Impact of PJM's Proposed Price Formation Reform on the Incentives for Increasing Generator Flexibility

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Executive Summary

Many trends in current power systems are increasing the importance of maintaining and increasing flexibility. Such trends include increasing generation from wind and solar energy, whose variability may be poorly correlated with electricity demand changes, increasing shares of self-scheduled generation, and volatile power flow changes at the borders of RTOs driven by small price differences. There are multiple types of flexibility that can be enhanced from a dispatchable thermal generator, including a higher maximum power output, a lower minimum power output, a faster startup time with a consequent reduction in startup cost, a faster ramp rate for changing the power output level while online, or combinations of these. However, many of these features reduce the costs to the system and to the consumer by shifting the more flexible generator to provide less energy or to be online for fewer hours, reducing energy revenue.

An increased incentive for generators to invest in and offer flexibility was one of several motivations for a recent proposal by PJM to reform its reserve market pricing formation. The PJM proposal consisted of increasing the amount of both synchronized (spinning) and offline (non-spinning) operating reserves, and to increase the prices paid to generators for reserves as well as for energy. The main elements of the proposal intended to achieve this impact are new Operating Reserve Demand Curves (ORDCs) with 20-40 gradually decreasing levels of penalties in place of the 2-step curves currently in use, an increase of the magnitude of the penalties for reserve shortages, and the introduction of a new 30-minute Secondary Reserve product.

This report examines the proposed changes to the ORDCs and the addition of the 30-minute reserves, and assesses the relative impacts of these changes on the financial incentives for natural gas combined cycle generators to invest in technology to increase the flexibility of their plants. The analysis simulates the Electricity Reliability Council of Texas (ERCOT) for the year 2016, superimposing either the current PJM ORDCs or the proposed ORDCs, and calculates the system costs, net revenues to each generator, and other metrics. The simulations are then repeated where one combined cycle generator receives a hypothetical upgrade to increase its flexibility. The change in net revenues to the owner of the upgraded generator offers a way to quantify the (dis)incentive to invest in flexibility. The comparison of this metric between the two reserve market designs provides a way to assess whether the proposed reserve market design improves or weakens the incentive for flexibility.

The results of the analysis strongly suggest that the proposed changes to the reserve market by PJM would in fact increase the incentives to invest in most types of flexibility. Upgrades to increase the maximum output, decrease the minimum output, increase the ramp limit, and combinations of all features would lead to a greater increase in net revenues (a proxy for generator profit) under the proposed design, as compared with current reserves. Only the incentive to invest in a faster startup time in is not improved by the proposed market change.

Table ES.1: Change (due to Reserve Design) in the Change (due to flexibility upgrade) of Annual Net Revenues to Owner ($M)

	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	4.3	1.5	2.2	0.0	2.4
G37	-0.2	0.4	2.2	-0.9	0.7
G50	3.2	2.2	1.6	0.5	-1.9

1. Background

Generator Flexibility

The recent and projected future increases in the share of variable renewable generation has been driving increased concern about the need for flexibility in the electric power system. Specifically, the combined effects of variability in demand, solar generation, and wind generation require that the dispatchable generation resources be constantly adjusted to maintain the demand-supply balance. Additional sources of stress on dispatchable generation resources include self-scheduled resources, for example cogeneration, and rapidly changing flows of power across the seams between RTOs driven by small price differences. To the extent that generation resources have wider operating ranges (higher maximum and/or lower minimum output limits), can ramp more quickly, or can startup more quickly and/or at lower cost, these resources can make it easier for the system to maintain balance between dispatchable supply and the net load.

Many previous studies have explored aspects of the value of increased flexibility from a variety of resource types, including renewables, storage, transmission, demand response, and more flexible thermal generators. In particular, there exist currently technological improvements via operational and physical changes that would enable natural gas combustion turbines, both simple cycle and combined cycle units, to operate at a lower minimum output, to operate at a higher maximum output, to ramp more quickly up or down while online, to start up more quickly from an offline state with corresponding lower startup costs, or any combination of the above. Any enhancement to the operating parameters will require investment by the unit owner and will require targeted R&D investments on the part of turbine manufacturers.

The potential barrier to many of these technologically feasible upgrades is that the generation resource owner will not make additional investments to enable flexibility, and subsequently offer this flexibility to the market, unless the change will improve the financial position of the resource. Some of the flexibility that can lower cost and improve the reliability of the system would entail shifting the use of the now more flexible resource to provide less energy and instead provide greater reserve capability. Unless the net revenue from the increased reserves and other ancillary services provision is greater than the reduction in energy revenues, the generator owner has no incentive to make such investments.

PJM's Reserve Market and Proposed Design Changes

Starting in 2017, and continuing up through early 2019, PJM developed a set of proposed reforms to their reserve market design and price formation to address shortcomings in the current design. The three main features that PJM has identified as problematic are:

- Synchronized reserves are separated into two products, Tier 1 and Tier 2, that face different rules and different compensation;
- The magnitude of penalties and the shape of the current operating reserve demand curve (ORDC) does not sufficiently encourage performance by resources providing reserves;
- There is misalignment of reserve products between the day-ahead and real-time markets that leads to insufficient procurement of reserves in advance.

The motivations for PJM to modify the reserve market design include providing transparency, maintaining reliability, providing incentives to follow commitment and dispatch instructions, and incentives to make continuing efficient investments. In particular, the latter motivation includes specifically an expressed desire in PJM documents to incentivize an increase in flexibility on the part of generation resources, recognizing the growing need for this flexibility to maintain reliability and simultaneously keep consumer costs low.

A series of stakeholder meetings in late 2018 and early 2019 failed to produce a positive vote to adopt the proposed reforms within the stakeholder voting rules for PJM. PJM subsequently submitted a filing to the Federal Energy Regulatory Commission (FERC) on March 29, 2019, arguing that current reserve market rules are unjust and unreasonable, and requesting that FERC order the new rules be adopted.

At the time of writing of this report, this filing remains open for public comment.

Objective of this Analysis

In this analysis, I examine one aspect of the proposed reforms in PJMs filing to FERC, and its impact on one of the criteria identified as a motivation. Specifically, I analyze the proposed changes to the ORDCs from the current curves used to the proposed new curves. The main objective of the analysis is to evaluate the assertion by PJM that the revised ORDCs would improve the incentive for flexible investments and operations by generators.

To perform this assessment, I adapt a modeling framework developed in collaboration with General Electric to quantify the economic value of several hypothetical flexibility enhancements that could be made to existing natural gas combustion turbines within combined cycle units. The model simulates a power system before and after each type of flexibility enhancement and calculates the net change in total system costs and the change in net revenue to the generation owner due to the upgrade. To explore the PJM proposal, I perform the analysis twice, once for the current ORDCs and a second time using the proposed ORDCs. The difference between the change in net revenue from the upgrade under the current ORDCs and the change under the proposed ORDCs provides an illustrative measure of the relative change in the incentive to invest in generator flexibility.

2. Methodology and Assumptions

Unit Commitment Model

The computational model used in this analysis is a deterministic unit commitment (UC) model. The UC model solves for the minimum cost schedule of commitment status and power output from all dispatchable generators subject to balancing supply and demand at every time period and the operational constraints of the generators. The UC model is used to determine which generators are online and which are offline for each hour of the simulation time horizon; when a generator is online, its power output must be between its minimum and maximum output levels; for some technology types, the minimum power output is significantly above zero.

The model minimizes the total variable cost over the entire time horizon, which includes the fuel cost of generation, the non-fuel variable operations and maintenance (O&M) cost of generation, and the costs of starting up generators when they transition from offline to online. In addition, the objective function that is minimized includes several penalty factors to ensure realistic solutions, including a penalty if demand is not completely satisfied in any given hour and a penalty if any renewable energy is curtailed. None of the results shown in this report contain any non-served demand or curtailed renewables. Finally, the ORDCs in this analysis are implemented also using a penalty in the objective function, defined by ORDC for the total procured reserves in each hour. This is described in more detail below.

The model minimizes the total cost while enforcing a number of system constraints, including:

- Demand is satisfied in all hours;
- Required reserves of each type are procured in each hour up to the point where the penalty from the ORDC exceeds the marginal cost of acquiring one more MW of reserve from a generator;
- Generators are either online or offline in each hour;
- Output from online generators are between their minimum and maximum output
- Changes in the power output between consecutive hours may not exceed the maximum ramp limit for that unit;
- If a unit is started up, it must remain online for a minimum number of hours;
- If a unit is shutdown, it must remain offline for a minimum number of hours;
- When a unit is started up, there is a delay before the unit becomes available to dispatch, and during these times it follows a prescribed power profile. The time lag, power profile during the startup ramp, and the startup costs all depend on the elapsed time since the generator last shutdown (i.e., its temperature).

The UC model used is implemented as a mixed integer linear program, using the GAMS software system, and solved using CPLEX 12. The detailed mathematical formulation and numerical parameter assumptions are provided in the technical appendix, and all code and data files are publicly available in a GitHib archive (http://github.com/mortpsu/PJMFlexibilityStudy).

The model used is the same fundamental approach as the software used to clear PJM's day-ahead market and those of other RTOs. The primary differences between the simulation here and actual markets are the absence of transmission grid detail that RTOs use to enforce security constraints, and the use of assumed cost parameters (described below and in the appendix in detail) rather than market bids. There is also no treatment in the simulation of load or renewable forecast uncertainty. Therefore, there is no equivalent in the simulations here of a real-time market, in which generator outputs are modified to adapt to revised load forecasts. Because there is no treatment of uncertainty in this analysis, the results most likely understate the value of the flexibility, which would increase in the presence of forecast uncertainty and subsequent adjustments to the dispatch.

ERCOT Simulation

In an effort to provide timely information about PJM's proposed reserve market reform, I have adapted a pre-existing model of the Electric Reliability Council of Texas (ERCOT), the power system that covers the majority of Texas. The data to model the PJM grid with the precision necessary to be informative was not available within the desired time frame. Nevertheless, the analysis in this report using the simulation of ERCOT with the addition of the PJM ORDCs provides qualitative and illustrative insights into the impact of the proposed reform on the incentives to increase flexibility. Here we provide high-level description of the assumptions used for the ERCOT representation; more details can be found in the technical appendix and the online archive.

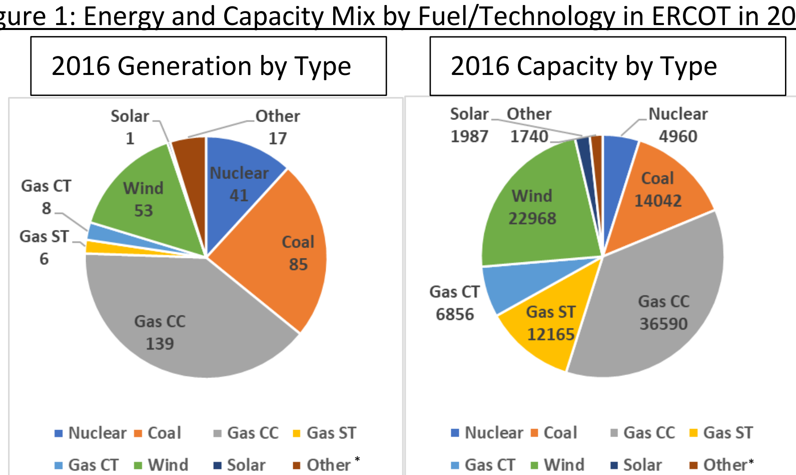
The analysis presented in this report is based on a simulation of ERCOT for the year 2016. The data and assumptions specific to ERCOT include the generator characteristics, the hourly pattern of demand, wind generation, and solar generation, and the historically observed real-time energy locational marginal prices (LMPs). The primary sources for the data are ERCOT's website, the U.S. EPA's eGRID database, and S&P Global Insight's SNL Energy commercial database.

The relative shares of capacity and of energy in 2016 are shown in Table 1 and Figure 1. The largest share of energy is from natural gas combined cycle generation, followed by coal steam and then wind generation. ERCOT has two operating nuclear plants for a total capacity of just under 5000 MW. ERCOT also retains a fair amount of older natural gas steam turbine units, which are largely used for load-following and peaking. Roughly one third of the natural gas combined cycle and natural gas combustion turbine (simple cycle) are co-generation units; the majority of these are self-scheduled and do not fully participate in the competitive energy market. The "Other" category in Table 1 and Figure 1 is an aggregate of internal combustion units (mostly diesel or natural gas), biomass, hydro, waste-steam, and other less common fuels and technologies.

Table 1: Energy and Capacity by Fuel/Technology in ERCOT in 2016

	Generation (millions of MWh)	Summer Capacity (MW)
Nuclear	41	4960
Coal	85	14042
Gas CC	139	36590
Gas ST	6	12165
Gas CT	8	6856
Wind	53	22968
Solar	1	1987
Other	17	1740

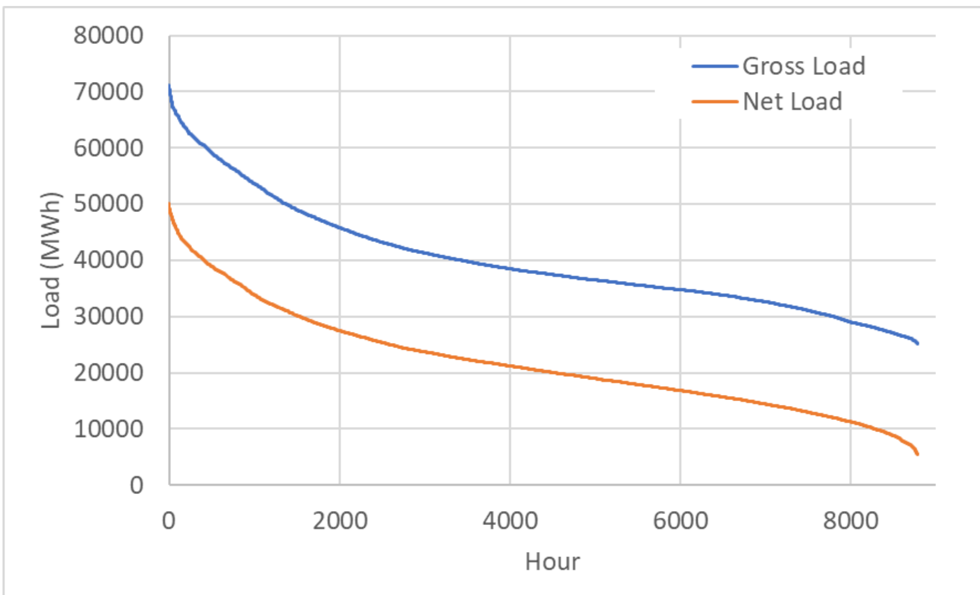
Figure 1: Energy and Capacity Mix by Fuel/Technology in ERCOT in 2016



*Other Includes: Internal Combustion/Diesel, Biomass, Hydro, Waste Steam, and other fuels.

The hourly load, wind, and solar generation in ERCOT in 2016 are available at ERCOT's website. The load duration curve for 2016 ERCOT native gross load is shown in Figure 2 below. Because the objective of the analysis here is to quantify the economic impacts of changes to the reserve markets and technology changes to generators that enhance their flexibility, the modeling approach focuses on representing the dispatchable portion of the ERCOT energy market, rather than explicitly modeling all generators. Specifically, the goal is to simulate the generators that participate in the ERCOT market and respond to ERCOT dispatch instructions. The model is therefore designed to meet the hourly net load, which is defined as the load minus the sum of nuclear generation, wind generation, solar generation, co-generation (non-dispatchable), and other non-dispatchable resources. The resulting net load is also shown in Figure 2; note that the load duration curves for the gross and net load do not necessarily occur in the same hours. In the model, the historically observed hourly net load in chronological order defines the demand in each hour.

Figure 2: Load Duration Curves for ERCOT Gross and Net Load in 2016



PJM Reserve Market Representation

To explore the impact of changes to the ORDCs for PJM, each set of ORDCs (current and proposed) are represented within the ERCOT simulation model. The current PJM ORDCs consist of one curve for 10-minute synchronized reserves for all hours of the year, and a second curve for 10-minute primary reserves for all hours. The synchronized reserve target can only be procured from online (spinning) resources, while the primary reserves met by the sum of spinning and non-spinning (offline quick-start) reserve capacity. Both curves have only two steps with penalties defined as:

Synchronized Reserve ORDC:

0– 1450 MW	\$850 / MW
1450–1640 MW	\$300 / MW
> 1640 MW	No penalty

Primary Reserve ORDC:

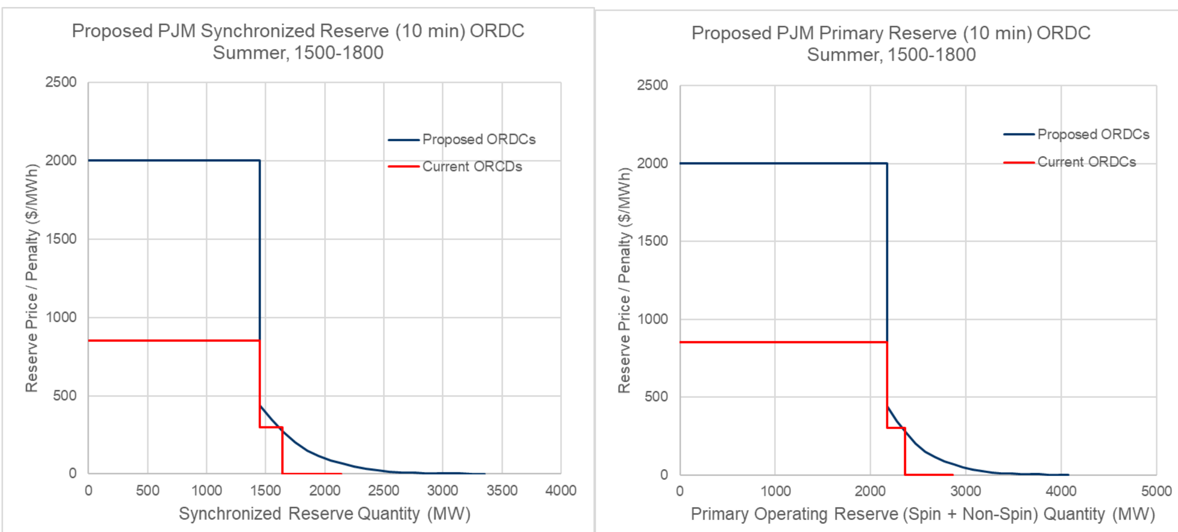
0– 2175 MW	$850 / MW
2175–2365 MW	$300 / MW
> 2365 MW	No penalty

The current ORDC curves are shown in Figure 3 below.

The proposed ORDCs are described elsewhere by PJM. In their proposal, PJM has defined six curves for each season, each for a four-hour period of the day, resulting in 24 curves for each reserve type. As an example, the proposed curves for summer hours 1500-1800 are shown below in Figure 3, along with the current PJM ORDCs, for both 10-minute Synchronized and 10-minute Primary reserves.

In addition to the Synchronized and Primary Reserves, the PJM proposal would add a third category, Secondary Reserves, which are a 30-minute product, and can be provided from either spinning or non-spinning reserves that can be delivered within 30 minutes.

Figure 3: Proposed and Current ORDCs for 10-minute Synchronized and 10-minute Primary Reserves (Summer 1500-1800).



The penalty from the ORDC is not necessarily the actual price of the reserve product. The solution of the unit commitment model includes the shadow prices of each constraint, which represents the marginal cost of meeting that constraint. The shadow prices on the reserve requirements of each category are the basis for the compensation for providing reserves. In the case of the proposed reserve market, there are three prices:

- Price of 10-minute Synchronized Reserves
- Price of 10-minute Primary Reserves
- Price of 30-minute Secondary Reserves

The cleared reserves from any given generator, however, consist of four types: 10-minute spinning (from online units), 10-minute non-spinning (from offline units that can start within 10 minutes), 30-minute spinning (from online units), and 30-minute non-spinning (from offline units that can start in less than 30 minutes).

The rules for determining payments to generators are as follows

1) For an online unit providing 10-minute spinning reserves, the unit receives the sum of all three prices (10-minute Synchronized Reserve Price, the 10-minute Primary Reserve Price, 30-minute Secondary reserve Price) for each MW of 10-minute reserve provided;
2) For an offline quick-start unit, the unit can receive the sum of the 10-minute Primary Reserve Price and the 30-minute Secondary Reserve Price for each MW of 10-minute non-spinning reserve provided;
3) For an online unit that provides 30-minute spinning reserves, the difference between the 10-minute and 30-minute reserves is paid at the Secondary Reserve Price;
4) For an offline quick-start unit that provides 30-minute non-spinning reserves, the difference between the 10-minute and 30-minute reserves is paid at the Secondary Reserve Price.

The analysis here does not distinguish between Tier 1 and Tier 2 reserve categories, and for simplicity treats all synchronized reserves consistently. No bidding by generators for reserves is assumed, and the prices paid are solely determined by the shadow prices in the model solution.

Experimental Design

The simulation of ERCOT is performed for every day of 2016, with the exception of Jan 1, Dec 30, and Dec 31 (to account for boundary conditions). The simulation for each day is repeated for different ORDC cases and different flexibility upgrade cases. For any given natural gas combined cycle generator in ERCOT that is identified as a potential candidate for upgrades, 12 simulations of each day are performed. The two ORDC cases are the current PJM ORDCs and the proposed ORDCs, as described above. For each ORDC case, a base case is simulated, assuming characteristics for all generators that approximate the historically observed generation patterns. In addition, five hypothetical upgrade cases are simulated in which the characteristics of the candidate generator are modified as follows:

- "Pmin": The minimum output of the generator is 15% lower than its previous minimum
- "Pmax": The maximum output of the generator is 20% higher than its previous maximum
- "Start": The startup time (from offline to at or above minimum output and available for dispatch) is reduced by as much as half and the startup cost is reduced by 75%
- "Ramp": The ramp limit of the generator is double its previous ramp limit
- "All": All four of the above modifications are made simultaneously.

The key results of each set of simulations for one candidate generator consist of the system savings, defined as the difference in total cost between the base case and one of the flexibility cases, and the change in net revenue to the upgraded generator. The net revenue in each case is calculated as the revenues (energy plus reserves) minus the costs (generation fuel costs, variable non-fuel O&M costs, and startup costs). The difference in net revenue between the base case and an upgrade case provides a measure of the incremental financial benefit to the owner of the increased flexibility. These quantities are calculated under the current PJM ORDCs and again under the proposed PJM ORDCs; the difference between the change in net revenue then provides a measure of the relative incentive to the generator owner to adopt the flexibility under each reserve market design.

The analysis presented below consists of the complete set of simulations for three candidate combined cycle generators in ERCOT, summarized in Table 2. We do not identify the actual plants in ERCOT and will refer to them using their ID within the model. These three units are chosen because they represent different dispatch patterns. G37 is a unit that runs more as a baseload unit, with the largest number of fired hours per year and the fewest starts per year from among these three. G35 is a mid-range unit that cycles frequently but not every day and has fewer fired hours than G37. G50 is at the lower end of the merit order among the combined cycle plants, and it cycles every day, and sometimes twice a day, with the fewest fired hours, the least energy provided, and the largest number of starts per year over 2016 from among these three.

Table 2: Candidate Generators for Hypothetical Flexibility Upgrade

Generator ID	TYPE	Capacity	Avg Heat Rate	CF	Hours Fired	# of Starts
G35	3x1 NGCC	650	7400	0.47	5680	249
G37	2x1 NGCC	520	7200	0.76	7884	28
G50	2x1 NGCC	550	7150	0.35	4243	400

3. Results of the Analysis

Comparison of ORDC Impacts for Base Case (No Upgrades)

Before presenting the impacts of flexibility upgrades on individual generators, the simulated prices and cleared quantities for reserves are summarized for the Base case (all generators assumed to have current operating parameters). Table 3 summarizes the hourly prices for energy and for the three reserve products in terms of percentiles of all hours in the 2016 simulations. The energy prices are only slightly higher under the proposed ORDCs. However, the 10-minute Synchronized and 10-minute Primary reserve prices are significantly higher. Under the current ORDC, the simulated 10-minute reserve prices are zero more than 50% of the time (similar to historical prices in PJM). In contrast, the 10-minute prices under the proposed ORDCs have a much higher probability of being non-zero, and a correspondingly higher probability of higher values. For example, only 2% of the hours have prices above $10/MWh for 10-minute Synchronized under the current ORDCs but 6% of the hours have prices above $10/MWh under the proposed ORDCs.

The cleared quantities of all reserve products (10-minute spinning and 10-minute non-spinning for both market designs, and 30-minute spinning and 30-minute non-spinning for the proposed design), are shown in Table 4. The proposed ORDCs clear higher amounts of 10-minute spinning reserves than the current ORDCs for almost every hour of the year, and slightly higher but comparable amounts of 10-minute non-spinning reserves for most hours of the year. In addition, the proposed design would clear significant quantities of 30-minute spinning reserves.

Table 3: Prices under Current and Proposed ORDCs for Base Case Simulations

	Energy Price		10-min Synch		10-min Primary		30-min Secondary
Percentile	Current	Proposed	Current	Proposed	Current	Proposed	Proposed
0.05	9.55	9.66	0.00	0.15	0.00	0.00	0.00
0.25	15.37	15.58	0.00	0.92	0.00	0.46	0.00
0.50	18.26	18.53	0.00	2.44	0.00	2.14	0.00
0.75	22.11	22.44	0.96	4.73	1.80	4.73	0.92
0.95	35.03	35.56	5.29	12.37	6.35	13.43	9.16
0.99	99.16	100.79	14.50	32.67	12.53	31.60	33.42

Table 4: Cleared Quantities of Reserves under Current and Proposed ORDCs for Base Case Simulations

	10-min Spinning		10-min Non-Spin		30-min Spin	30-min Non-Spin
Percentile	Current	Proposed	Current	Proposed	Proposed	Proposed
0.05	1640	2484	396	401	2393	401
0.25	1640	2750	561	559	3296	559
0.50	1665	2867	709	703	4336	703
0.75	1806	2981	929	950	4806	950
0.95	1969	3159	1393	1376	5227	1376
0.99	2050	3304	1614	1662	5454	1662

Annual Aggregate Impacts of Flexibility Upgrades

The 2016 ERCOT simulations were performed for the three candidate combined cycle units as described in the previous section, and the total system cost and net revenues to the candidate unit were determined for each of the ORDC/Flexibility combinations. The difference between the total system cost for each day between each flexibility upgrade case and the base case (for the same ORDC assumptions) were calculated for each day and summed over all days. The resulting cumulative change in total costs are given in Table 5, in Millions of $. This savings quantifies the reduction in the total variable costs to meet the load and reserve requirements over the simulated year due to the increased flexibility of the generator (all other generators remain unchanged). The reduction in costs is a useful proxy for the reduction in the cost of electricity costs, since the generation costs would be paid by the distribution utilities, and then reflected in the rates that consumers pay.

The pattern of savings under the current ORDCs and reserve market design are similar across the three candidate generators. The greatest savings would result from an increase in flexibility for all the characteristics at the same time: lower Pmin, higher Pmax, faster/cheaper startup, and faster ramp. After that, the next greatest savings occurs from an increase in the maximum output. The other three types of flexibility result in savings of a similar magnitude.

The relative savings by type of flexibility also follows the same trend under the proposed ORDC and reserve market design. However, an upgrade undertaken if the new reserve market were in place would lead to significantly greater savings, from a 60% increase to a doubling of savings from the very same technological modification. This provides suggestive evidence that flexibility will be more valuable to the system and to the consumer under the proposed reserve market design.

Table 5: Annual System Savings from Flexibility Upgrade ($ Million)

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	Current	$15 M	$5 M	$7 M	$4 M	$4 M
	Proposed	$26 M	$8 M	$14 M	$10 M	$10 M
G37	Current	$12 M	$4 M	$7 M	$2 M	$3 M
	Proposed	$24 M	$8 M	$13 M	$7 M	$10 M
G50	Current	$15 M	$4 M	$8 M	$4 M	$3 M
	Proposed	$23 M	$8 M	$13 M	$9 M	$9 M

In a competitive market, whether PJM, ERCOT, or any other, a generator owner is less concerned with system savings than with the financial returns on their asset. Therefore, a critical outcome is the relative change in the net revenue to that unit from the upgrade. Table 6 shows the change in the cumulative annual net revenue to the upgraded generator in millions of $, calculated as the difference between the net revenue after the upgrade minus the net revenue before the upgrade (for the same ORDC case). Under the current ORDC and reserve market design, the greatest increase in net revenue would come from upgrading all the flexibility features at the same time, and the second greatest would be the faster startup only upgrade. For some of the plants, an upgrade to lower the minimum output or to have a faster ramp rate would actually lead to lower net revenues. Thus, under the current PJ ORDCs, there is a financial disincentive for owners to adopt these upgrades, even though the system cost would be lower.

The relative pattern of net revenue changes from upgrades remains the same under the proposed ORDCs, but in almost all cases, the increase in net revenue is larger under the proposed ORDCs relative to the current curves. The upgrades that under the current ORDCs would have resulted in a decrease in net revenue would result in a modest but positive increase in net revenue under the proposed ORDCs. Only in the case of G50 with the ramp rate only upgrade would net revenues decrease more under the proposed ORDCs.

In general, the pattern of results indicates that the gains to the generator owner of increasing the flexibility of their plant would be greater under the proposed reserve market design. In a system with greater procurement of reserves by the system, higher reserve prices, and higher energy prices, the incentives for investing in flexibility are substantially greater.

Table 6: Change in Annual Net Revenue to Generator Owner from Flexibility Upgrade ($ Million)

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	Current	5.1	-0.5	0.3	3.9	-1.6
	Proposed	9.4	1.0	2.5	3.9	0.9
	Difference	4.3	1.5	2.2	0.0	2.4
G37	Current	7.2	0.5	0.4	4.5	0.0
	Proposed	6.9	0.9	2.5	3.6	0.7
	Difference	-0.2	0.4	2.2	-0.9	0.7
G50	Current	4.0	-1.3	0.2	2.3	0.0
	Proposed	7.2	0.9	1.8	2.7	-1.9
	Difference	3.2	2.2	1.6	0.5	-1.9

An alternative calculation provides another way to assess to the impact of the reserve market design on incentives for flexibility. Whereas the results above compared the net revenues before and after an upgrade for the same reserve market, we can also compare the net revenues for the same plant and same technological characteristics between the current and the proposed ORDCs, as shown in Table 7. For example, for G35 as operated today (no upgrade), just the change in the ORDCs would increase the annual net revenue to the owner by $1.5M. However, the version of G35 with higher max output, lower min output, faster startup, and faster ramp would increase its net revenue by $4.7M from the reserve market change alone. In other words, the more flexible version of the generator gains much more from the market change than the original less flexible version. The pattern of greater gains from the market change for more flexible versions is generally consistent.

The one type of flexibility that would not gain from the reserve market change are units that only have faster startup capability. The modified reserve price formation and reserve targets does not appear to improve the incentives for decreasing the startup time for generators. If this greater fast start capability is needed to improve reliability or reduce costs to a system, some alternative ancillary market or incentive would need to be developed.

Overall, the pattern of findings from examining several different candidate plants, several different flexibility upgrades, and comparing the financial impacts on the generator provide evidence that PJM's proposed reserve market and ORDCs would increase the incentive for investments in flexibility.

Table 7: Change in Annual Net Revenue to Generator Owner from Reserve Market Change ($ Million)

	Current Unit	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	1.5	4.7	2.9	3.5	1.5	3.6
G37	3.5	2.6	3.8	5.2	2.2	4.2
G50	0.4	3.1	2.6	1.5	0.7	-1.4

Examples of Individual Days

To provide additional insight into the annual aggregate results presented in the previous section, we present the detailed results from two examples of one specific day and one specific upgrade to one of the generators.

Example #1: June 8, 2016, G35, Upgrade All Features

As a first example, this section shows the detailed results from June 8, 2016. This day is a representative example of a summer day. The load and net load are high but are not extreme peak episodes. The load, wind generation, and net load for this day are all roughly the 80th percentile for 2016. However, the pattern of renewable generation causes the net load to peak earlier than the actual load; the load and net load for this day are shown in Figure 4.

To establish the reference point before examining the impact of the upgrade, Figure 5 shows the impacts of the reserve market change on the base case (no flexibility upgrade) in terms of prices. In the upper left, the real-time LMPs over the simulated day are shown for both ORDC cases, which have minimal differences. Under the current PJM ORDCs, there is a shortage of spinning reserves at 1500, due to insufficient online resources, causing a price spike of $300 from the penalty. At most other times, the higher demand for spinning and primary 10-minute reserves under the proposed ORDCs results in higher prices, and the additional demand for 30-minute resources provides additional potential reserve revenue.

The change in net revenues to the owner of G35 due to the upgrade for the one day are shown in Table 8 for both ORDC cases and for every upgrade case. If G35 has upgraded all the flexibility features, the net revenue would increase by $18K under current ORDCs and by $40K under the proposed ORDCs, more than a doubling. The incremental gain to the owner from the upgrade is roughly doubled by the change in the ORDCs. If the owner had already made the upgrade to the more flexible version, the change in market rules would have increased the net revenue, but the original, less flexible current unit would have been worse off after the market rule change for this day.

Figure 4: Gross and Net Load for June 8, 2016 Simulations

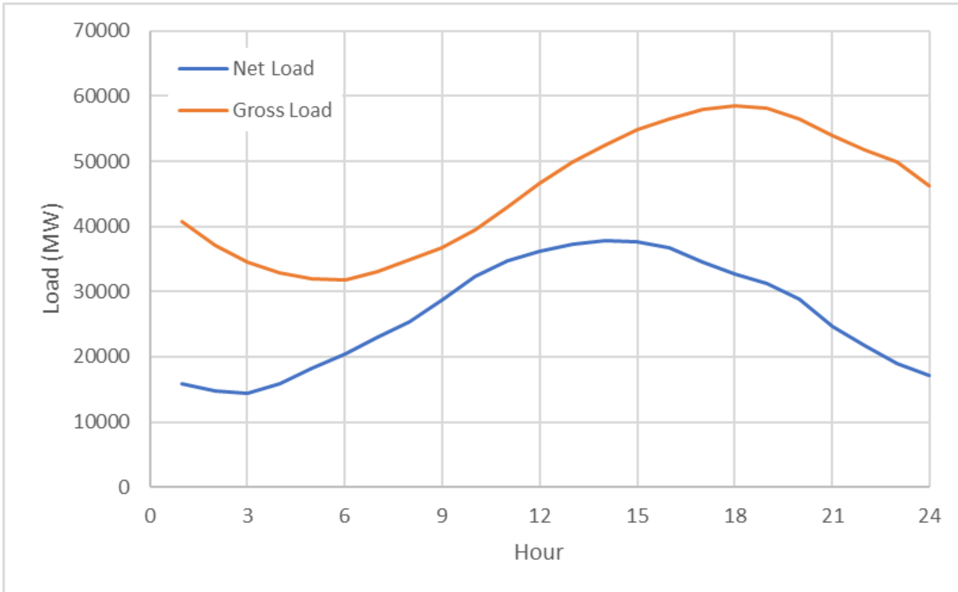


Figure 5: Prices for both ORDC cases for June 8, 2016 Simulations (No Upgrade)

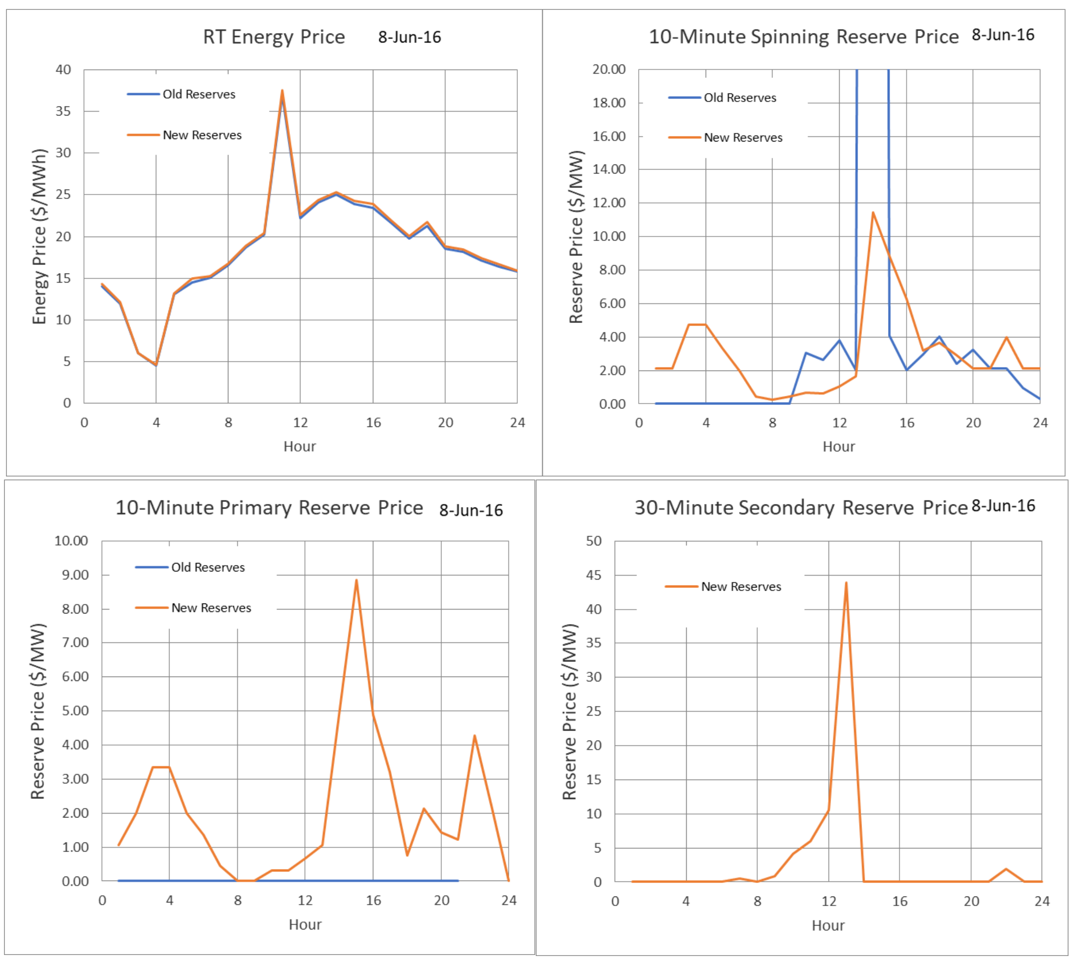


Table 8: Net Revenue to Owner of G35 for June 8, 2016 Simulations

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
Change in Net Revenue	**Current**	$18K	-$8K	$0.9K	$14K	$0.6K
	Proposed	$40K	$5K	$10K	$22K	$3K
Change due to Reserve Market Design Change	Current Unit	$17K	$9K	$5K	$4K	-$2K
	-4K					

Figure 6 shows the generation from G35 for each hour of the day before and after the ALL upgrade under both reserve market designs. For the current reserve market, the impact of the upgrade is that G35 would start up slightly later (because it starts faster) and begin the evening ramp-down slightly sooner. Under the proposed reserve market, the base version of G35 would remain online overnight at its minimum output in order to provide reserves. However, after the upgrade, the faster startup capability allows the system to take G35 offline overnight (keeping a different unit online to provide the reserves), and then bring it online for the peak hours. The upgraded unit is able to provide more energy during the peak hours and also more reserves (see Figure 7). Under both reserve markets, the upgraded G35 provides more reserves than the base version of the unit.

Figure 6: Generation from G35 on June 8, 2016 (Base vs. All Upgrade, both ORDC cases)

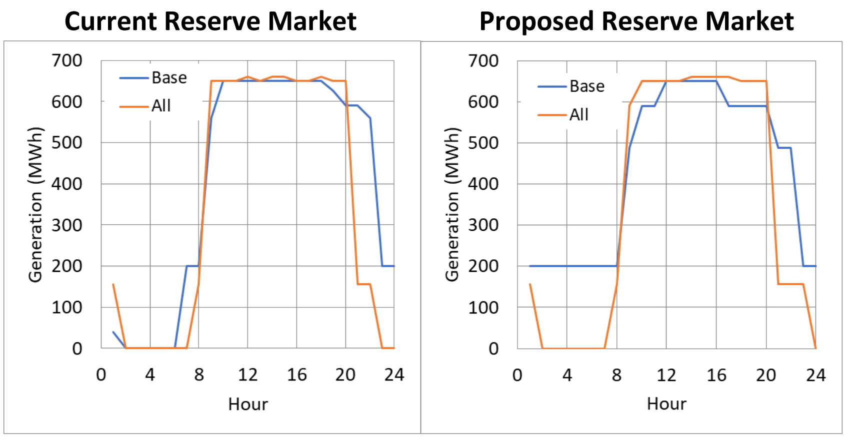


Figure 7: Reserves Cleared from G35 on June 8, 2016 (Base vs. All Upgrade, both ORDC cases)

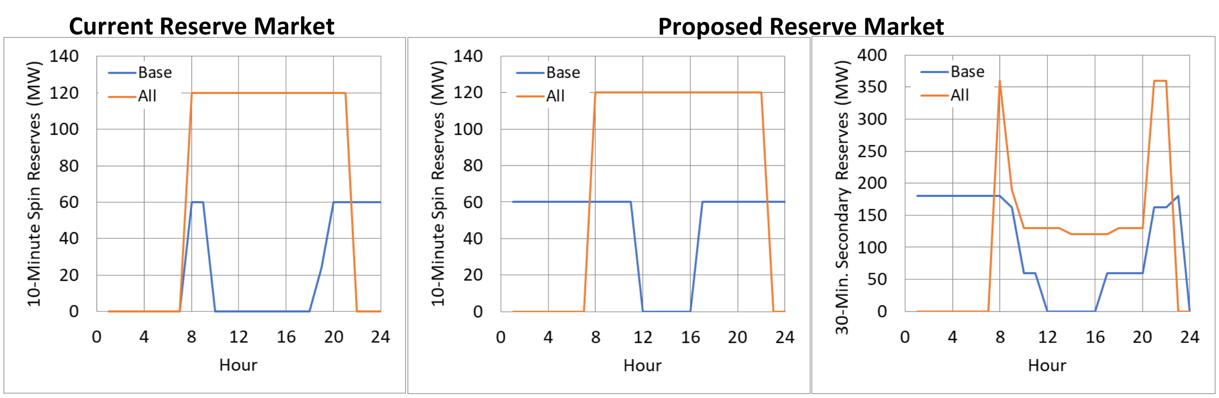
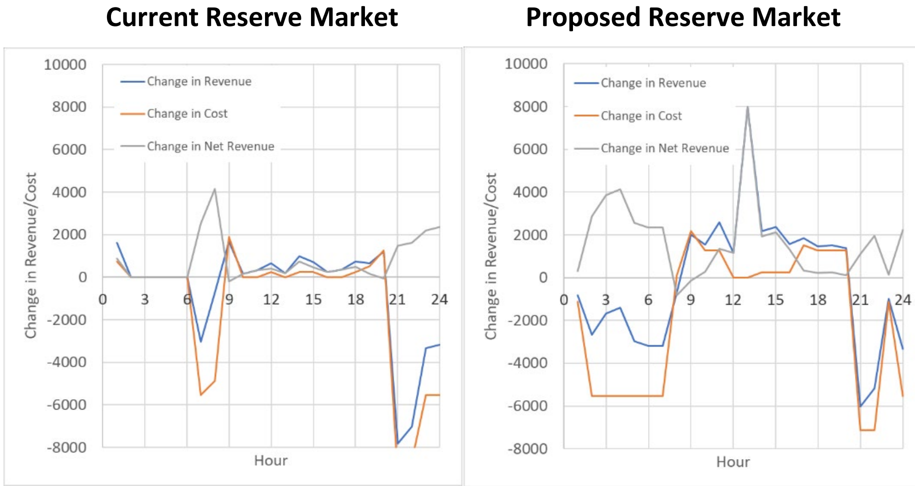


Figure 8: Changes to Revenue, Cost, and Net Revenue for G35 on June 8, 2016 (All Upgrade - Base)



Under the current reserve market design, the increase in net revenue from the upgrade is mainly due to savings from reducing production during less profitable offpeak times. This also occurs under the proposed reserve market, but in addition there is a significant gain in revenue from reserves during the peak hours (1100 – 1700). The breakdown of changes to costs and revenues due to the upgrade are shown in Table 9. Under both reserve designs, the energy revenues and the costs decrease after the upgrade, but under the proposed design, an increase in reserve revenues offsets much of the energy revenue reduction.

Table 9: Changes in Costs and Revenues from ALL Upgrade to Owner of G35 for June 8, 2016

Impact of Upgrade ALL Features	Current	Proposed
Change in Revenue ($)	$36K	$95K
Change in Cost ($)	-$14K	-$14K
Change in Net Revenue ($)	$50K	$109K
Change in Energy Rev ($)	$34K	$90K
Change in Reserve Rev ($)	$2K	$5K
Change in Gen (MWh)	-438	-450
Change in Reserves (MW)	540	480

Example #2: November 22, 2016, G35, Upgrade All Features

The majority of the days on which the gains from upgrading are substantially better under the proposed reserve market relative to the current market are in the spring and fall seasons. As a second example, this section shows the detailed results from November 22, 2016. This day is a representative example of a fall/winter day. The load and net load are relatively low, and the share of generation from wind is large. However, the wind decreases during the overnight hours, requiring dispatchable generation to increase output and leading to a temporary shortage of reserves; the load and net load for this day are shown in Figure 9.

Figure 10 shows the impacts of reserve market change on the base case (no flexibility upgrade) in terms of prices. In the upper left, the real-time LMPs over the simulated day are shown for both ORDC cases, which have minimal differences. The overnight shortage of reserves due to the decrease in wind generation causes price spikes under both market designs. However, the proposed ORDCs would result in higher reserve prices at their peak.

The change in net revenues to the owner of G35 due to the upgrade for the one day are shown in Table 10 for both ORDC cases and for every upgrade case. If G35 has its current capabilities, the net revenue would increase by $45K under current ORDCs and by $217K under the proposed ORDCs. If the owner had already upgraded to the more flexible version, the change in market rules would have substantially increased the net revenue, but the original, less flexible current unit would have been worse off after the market rule change on this day.

Figure 11 shows the generation from G35 for each hour of the day before and after the ALL upgrade under both reserve market designs. For the current reserve market, the impact of the upgrade is that G35 would come online sooner, produce more energy during the two peak periods, and remain at a lower minimum output (providing reserves) at other times. The generation patterns are similar under the proposed reserve market, except that with or without the upgrade, less energy is produced during the first morning peak in order to provide more reserves. Under both reserve markets, the upgraded G35 provides more reserves than the base version of the unit, and can begin providing reserves sooner, taking advantage of the reserve price spike.

Figure 9: Gross and Net Load for November 22, 2016 Simulations

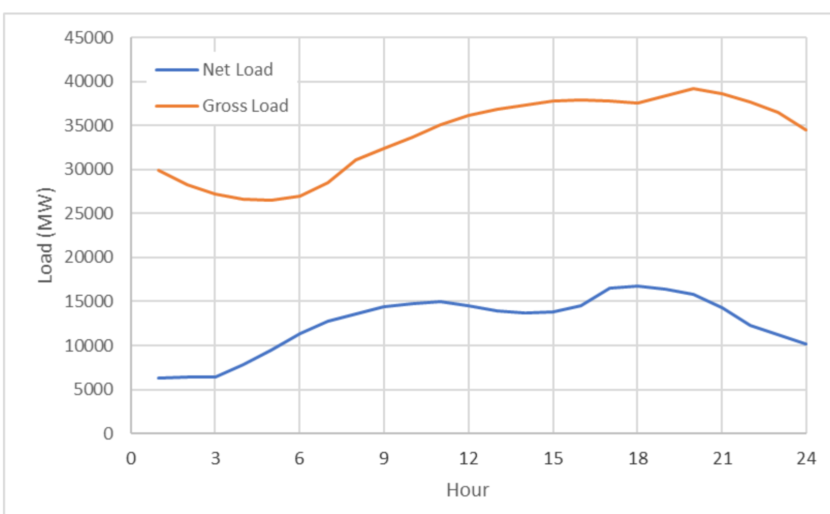


Figure 10: Prices for both ORDC cases for November 22, 2016 Simulations (No Upgrade)

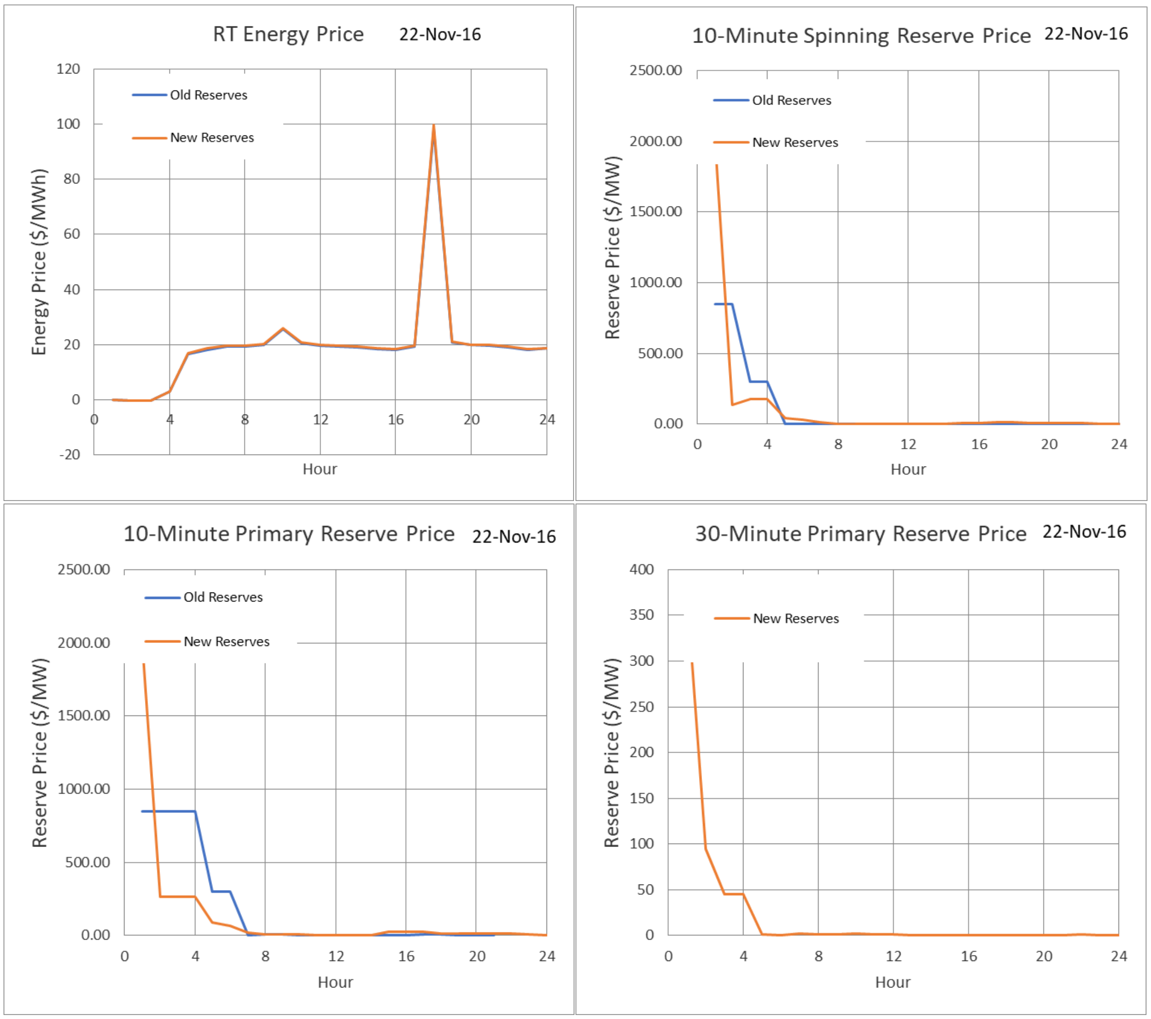


Table 10: Net Revenue to Owner of G35 for November 22, 2016 Simulations

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
Change in Net Revenue	Current	$45K	-$31K	-$27K	$154K	$95K
	Proposed	$217K	$4K	$5K	$42K	$184K
Change due to Reserve Market Design Change	Current Unit -3K	$170K	$32K	$30K	-$114K	$87K

Figure 11: Generation from G35 on November 22, 2016 (Base vs. All Upgrade, both ORDC cases)

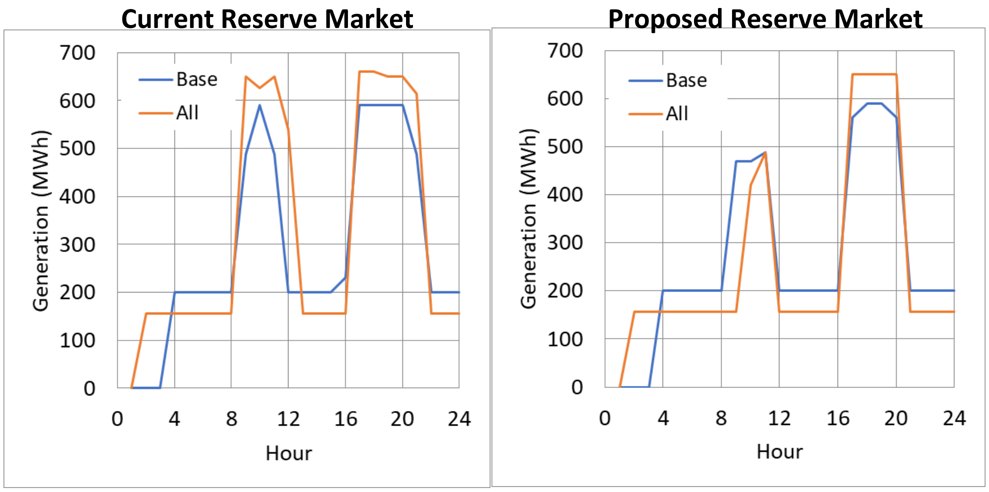


Figure 12: Reserves Cleared from G35 on November 22, 2016 (Base vs. All Upgrade, both ORDC cases)

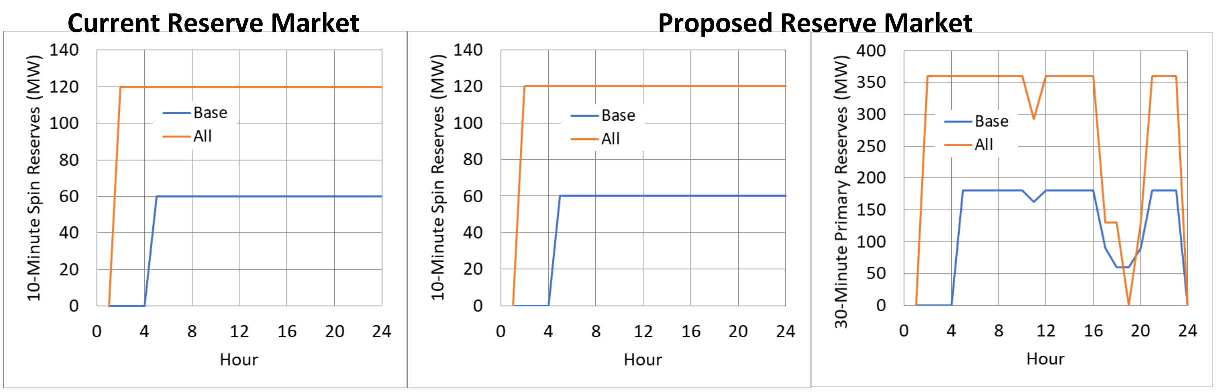
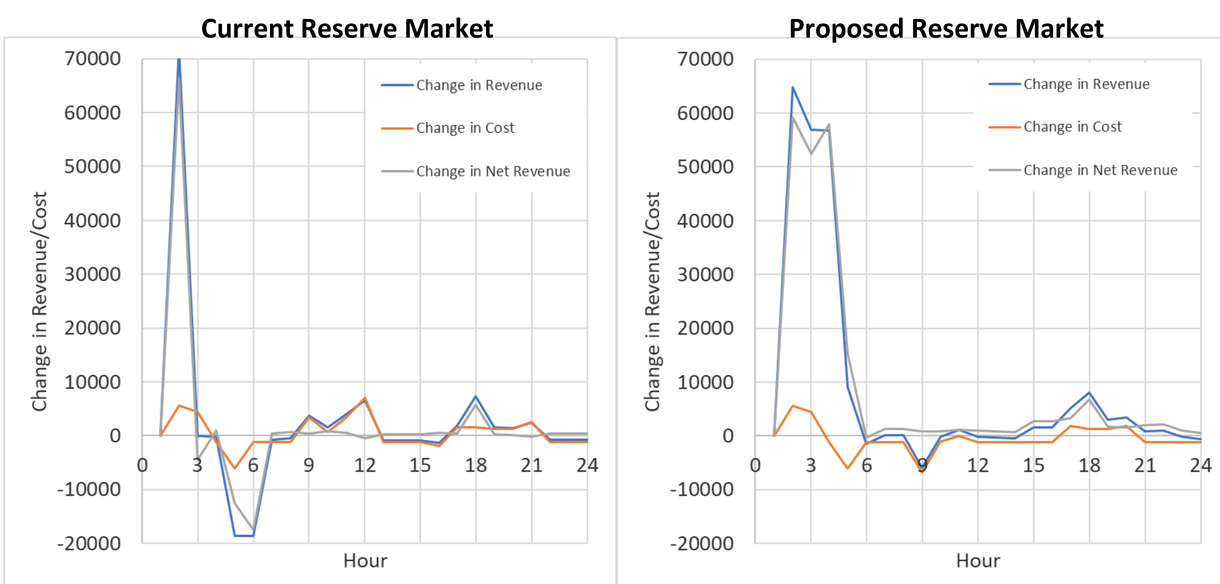


Figure 13: Changes to Revenue, Cost, and Net Revenue for G35 on November 22, 2016 (All - Base)



Under both reserve markets, G35 would increase its net revenue with the greater flexibility by receiving more of the reserve revenue from the price spike in the first few hours of the day. The impact of the proposed reserve market design is a larger increase in the reserve revenues for more hours. The higher reserve prices would reward the flexibility from the upgrade more than the current design.

Table 11: Changes in Costs and Revenues from ALL Upgrade to Owner of G35 for November 22, 2016

Impact of Upgrade ALL Features	Current	Proposed
Change in Revenue ($)	$58K	$204K
Change in Cost ($)	$14K	-$12K
Change in Net Revenue ($)	$45K	$217K
Change in Energy Rev ($)	$18K	-$8K
Change in Reserve Rev ($)	$41K	$213K
Change in Gen (MWh)	841	-368
Change in Reserves (MW)	1560	1560

4. Conclusions

As in all simulation studies, the analysis presented here is a simplified representation of the dynamics involved in scheduling and dispatching of generators in a competitive energy market. Many aspects of actual electricity markets are omitted for simplicity and tractability, such as transmission network flows, strategic bidding by market participants, uncertainty and the adjustments between day-ahead and real-time markets, and many others. Furthermore, the numerical simulations are an artificial experiment, layering a representation of the main features of the ERCOT market with the specific operating reserve market designs (current and proposed) from PJM.

Nevertheless, the results from the simulations suggest a clear directional trend: a change in reserve markets that procures more operational reserves and sets a higher and more gradually increasing penalty on reserve shortages, which induces higher prices, increases the incentives for investments in flexibility. The greater incentive for flexibility is suggested by the increase in net revenue to the generator owner from enhancing flexibility is greater under the proposed reserve market. In addition, the increase in net revenue to the generator from the reserve market design change is greater for the more flexible version of the otherwise identical generator, so the more flexible generators would gain the most from the market design changes.

The greater incentives for flexibility from increased system demand for reserves and higher reserve prices is consistent with how each type of flexibility allows the system to reduce costs. A lower minimum output results in a generator being dispatched lower during off peak times, reducing energy revenues. However, a lower output level and faster ramp rate both allow that unit to provide more reserves. If reserves are priced higher, that can offset some of the losses. If a generator has a higher maximum output, it will be dispatched higher during peak hours to displace less efficient generators. In this situation, the increase in energy prices that is a consequence of the greater demand for reserves would increase the benefit to the generator. The only type of flexibility that receives little benefit from the change in reserves is a faster startup capability. This feature tends to lead to the system scheduling the unit offline for more hours per year, with more startups, and often delays the startup time until later in the day. With fewer hours online, there is less opportunity to receive either energy or reserve revenues.

Several of the omitted aspects of actual power systems would most likely further increase the benefits from increasing flexibility to the system and also would likely increase the gain from a change in the reserve market design. One important factor is uncertainty in load and renewable generation forecasts. If the projected net load over the next few hours from any point in time is greater, the need for flexibility and reserves will increase. If a sudden change in renewable output occurs over a short time, insufficient synchronized reserves would require starting high-cost and inefficient peaking units. If the renewable output increased rapidly, generators that can dispatch lower without shutting down also save the system the costs of starting up again later. The additional benefits under uncertainty would be further increased if examined over smaller time steps than hourly, such as 5-minute or 10-minute increments. Finally, the current trend of an increasing share of energy from wind and solar over the next several years and beyond will also further increase the stress on the dispatchable generators, and will require more flexibility from the units that will likely need to cycle more, ramp more quickly over a wider operating range, and remain financially viable with fewer operating hours.

Changes such as the reserve pricing proposal from PJM will be increasingly needed by RTOs as these trends continue. In the absence of ancillary service market changes or other changes that reward those resources that keep demand and supply in balance and maintain reliability, the technological changes to provide these services are less likely to be adopted.

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