Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal

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Table of Contents

Executive Summary

We were asked by the Electric Reliability Council of Texas (ERCOT) to evaluate the economic benefits of its proposed Future Ancillary Services (FAS) design. ERCOT proposed FAS to efficiently maintain grid reliability as inverter-based generation displaces traditional generation and as new technologies offer new ways to provide ancillary services.

The essential differences between FAS and ERCOT's Current Ancillary Services (CAS) design are that FAS unbundles ancillary services and fine-tunes service requirements to system conditions and resource capabilities. FAS unbundles CAS's Responsive Reserve service (RRS)—the service used to arrest frequency decay and restore frequency to 60 Hz in the event of the two largest contingencies—into three distinct services: Fast Frequency Response, Primary Frequency Response, and Contingency Reserve, as described in Section II.B. These services enable new technologies and more load resources to provide valuable services that are compatible with their capabilities.

Both of these broad changes—unbundling services and fine-tuning requirements—represent good market design in that they increase the possible ways to meet reliability objectives, and they avoid procuring more reserves than necessary. Our analysis informs the nature and magnitude of FAS's benefits, which ERCOT and stakeholders can compare to the implementation costs of FAS. We focused primarily on the economic benefits but, for completeness, we also describe reliability benefits and costs. We did not translate reliability benefits into measures of economic savings.

The reliability benefits of FAS include:

1. After a contingency, FAS will more readily arrest frequency decay by deploying very fast resources providing FFR1 (*e.g.*, advanced batteries). This saves other frequency response (FFR2) providers in reserve in case a larger contingency occurs shortly thereafter.
2. FAS recognizes the relative effectiveness of different types of responsive reserves (PFR and FFR) through an "equivalency ratio," which depends on hourly system inertia. In FAS, the equivalency ratio is recognized in the AS market clearing engine. This allows for a tighter procurement of frequency responsive reserves but avoids the reliability risk of substituting less effective resources for more effective ones, which is a current practice under CAS.

3. FAS rates providers of frequency response based on their past performance. This mechanism ensures that the system always has as much capability as intended and provides incentive for resources to improve their performance. In contrast, CAS allows all qualified resources to provide up to 20% of their maximum capacity towards RRS, irrespective of their performance in past events.
4. FAS separates replacement reserves from other frequency reserves. This allows for more effective procurment from a larger pool of resources that can be available in 10 minutes. This leads to faster frequency restoration following a contingency event and faster replacement of frequency response resources so they can prepare for the next event.
5. FAS ensures that regulation reserves are spread among at least four resources, which improves the system response acuracy and reliability.

The economic benefits we quantified are the production cost savings from a more efficient commitment and dispatch, as FAS enables the most economic resources to meet a more finely-tuned set of requirements. We estimated the savings by first comparing the quantities of each AS product needed under CAS and FAS designs—and we found that FAS requires less generation spinning and held for reserves. We then estimated the cost savings resulting from FAS's reduced quantities.

The quantities of ancillary services needed depend on AS design and system conditions. We analyzed three scenarios that ERCOT and stakeholders had requested: (1) a 2016 Current Trends scenario that reflects expected market and system conditions for next year; (2) a 2024 Current Trends scenario based on ERCOT's 2014 Long-Term System Assessment (LTSA) scenario (developed in 2013) with additional wind and gas resources; and (3) a Stringent Environmental scenario from the same LTSA with increased wind and solar generation and a $45 per ton price of CO_2 allowances. This scenario was originally envisioned as a system stress case in which responsive reserve requirements increases as a result of renewable generation displacing thermal generation and lowering system inertia. However, it did not prove to have lower system inertia and correspondingly higher reserve requirements as anticipated. System inertia actually increased in most hours because coal generation was displaced by not only renewable generation but also combined-cycle (CC) generation, which has nearly twice the inertia per MW as coal. As a result, we chose not to evaluate the Stringent Environmental scenario further. (An alternative scenario with low load growth and enough renewable generation to displace both coal and combined-cycle generation might have had lower inertia and greater requirements for responsive reserves, but we did not construct such a scenario).

For the remaining scenarios, ERCOT staff determined hourly requirements of each service based on PLEXOS simulations they conducted under our direction. We found that FAS requires less thermal generation spinning to provide Primary Frequency Response (PFR) since it enables efficient substitution of load resources and new technology providing Fast Frequency Response (FFR). This substitution results from:

- Incorporating a PFR-FFR equivalency ratio into the market clearing engine
- Removing the 50% limit on participation of Load Resources that exists for Responsive Reserve Service under the CAS design
- Introducing the FFR1 product to enable new technologies

On average, we found PFR reductions (compared to Gen-RRS under CAS) of approximately 9%: 140 MW in 2016 and between 129 and 186 MW in 2024, depending on how much new technology or additional Load Resources enter to provide FFR. In addition to these savings in meeting frequency responsive needs, we also found savings in providing replacement reserves. Fine-tuning requirements to system conditions allows 756 and 790 MW less non-spinning capacity to be held in reserve in 2016 and 2024, respectively. (These PFR and non-spin reductions differ under alternative assumptions discussed below).

We estimated the economic savings from FAS's reduced AS quantities, analyzing two separate and additive components of the production cost of providing ancillary services: *day-ahead energy opportunity costs*, which reflect the cost of committing and holding (often inframarginal) capacity in reserves, considering only the expected value of real-time prices across all possible real-time system conditions; and *real-time option value foregone*, considering the volatility of real-time prices around the expected value. It reflects the cost of holding reserves and losing the option to change operations as different real-time conditions are realized. The real-time cost also accounts for the possibility of committed providers experiencing a forced outage and having to replace their capacity with other resources on short notice.

We estimated day-ahead cost savings using the PLEXOS model to simulate unit commitment and dispatch in FAS vs. CAS. PLEXOS approximates day-ahead as opposed to real-time conditions since it does not simulate the distribution of unexpected conditions that can occur in real time. In our 2016 simulations, FAS's reduced procurement of PFR reduces day-ahead production costs by $9.1 million per year because less combined-cycle capacity must be committed, avoiding startup costs and displacement of lower-cost coal generation. In 2024, day-ahead production costs decrease by $1.2 million per year without new technology and $3.4 million per year with new technology providing additional FFR. Simulated savings are less in 2024 than in 2016 because higher assumed net loads cause coal to become fully inframarginal, so marginal changes in CC commitment affect coal generation minimally. As for differences in replacement reserves between CAS and FAS (*i.e.*, with less Contingency Reserve under FAS than Non-Spinning Reserve under CAS), they have little effect on day-ahead production costs since they are provided mainly by offline resources.

We estimated real-time optionality savings separately, by analyzing historical capacity offers into ERCOT's AS markets. Ancillary service providers bear real-time costs when they commit their capacity for reserves because they are, in effect, restricting their participation in the real-time market and foregoing potential real-time revenue. We assume that capacity offers into the AS markets are a direct representation of these real-time opportunity costs. To estimate the associated cost of each AS on a system-wide basis, we compute the area under the offer curves to arrive at an average cost per MWh for each daily hour (1 through 24) in each month in 2014. We then conservatively apply those *average* costs to the hourly quantities of similar services procured in each future scenario.[1] We found that, with its lower quantities of PFR procured, FAS saves $3.2 million in real-time opportunity costs in 2016 and between $3.3 and $4.8 million in 2024, depending on the amount of new technology participating. In addition, with its lower quantities of replacement reserves procured (*i.e.*, with less Contingency Reserve under FAS than Non-Spinning Reserve under CAS), FAS saves $9.2 million in real-time opportunity costs in 2016 and $11.2 million in 2024.

Combining day-ahead and real-time opportunity costs, we find total annual benefits of $21.5 million per year in 2016 and between $15.7 and $19.4 million per year in 2024 under Current Trends, depending on the participation of new technology. Assuming the annual benefits found for the study years of the analysis persist at similar levels for ten years, the cumulative benefit would be on the order of $200 million, before discounting.

However, the benefits of FAS depend on how FAS and CAS are each defined. Our analysis was based on CAS and FAS specifications that were current in the spring of 2015. But since ancillary

[1] Applying the average cost is conservative since the marginal cost on the offer curve is a more economically relevant measure of the change in cost associated with marginal changes in quantities, and the marginal cost is about 4 times higher than the average cost in this case.

service market rules continue to change, we analyzed two sets of alternative assumptions reflecting recent developments. One set of these assumptions increased the benefits of FAS and the other set decreased them. The ERCOT Board recently approved an amendment to CAS that would reduce the average Non-Spinning Reserve procurement from 1,931 MW to 1,464 MW in 2016 and from 2,000 MW to 1,464 MW in 2024. These reductions in CAS requirements reduce the savings attributable to FAS's tighter replacement reserve requirements by $6.4 million in 2016 and $8.4 million in 2024. On the other hand, in mid-September 2015, North American Electric Reliability Corporation (NERC) released new standards that reduced the Minimum PFR requirement from 1,240 MW to 1,143 MW. The Minimum PFR change has a greater effect in FAS than CAS due to FAS's recognition of the equivalency ratio between FFR and PFR resources as well as the removal of the 50% limit on Load Resource participation. PFR procurement savings increase from 140 to 220 MW in 2016, resulting in $6.9 million additional savings, and from 129 to between 207 and 266 MW in 2024, depending on the participation of new technology, resulting in $2.8 to $3.4 million additional annual savings. When both the NSRS and PFR changes are applied together, however, the results are similar to the savings reported in our original analysis.

Table ES-1: Summary of Annual Benefits

Case	2016	2024*
Annual Benefits	$21.5	$19.4
Annual Benefits with Alternative Assumptions**	$22.0	$14.5

*2024 benefits include the effects of new technology enabled by FAS
**Alternative Assumptions include updated NSRS and Minimum PFR requirements

While actual benefits are uncertain, we believe the general magnitude of our estimates to be robust. Our estimates reflect a simple fact: efficient procurement by FAS reduces the quantities of ancillary services needed, which will save money as long as ancillary services are costly to provide (*i.e.*, their price is positive). Furthermore, our estimates are conservative in several ways: (1) in our CAS cases, we determined reserve requirement on a day-ahead basis, while CAS requirements are actually determined more than a year in advance, which significantly increases the quantity of reserves procured; (2) we applied average rather than marginal costs to estimate real-time opportunity costs; and (3) we did not attribute economic value to the reliability benefits of FAS.

With respect to the cost of implementing FAS, we understand that ERCOT has estimated a one-time cost of $12 to $15 million. These costs are very small compared to the estimated benefits of roughly $20 million per year. If discounting 10 years of benefits at 7.5%, their present value would be $137 million. The net present value accounting for implementation costs would be over $120 million, and the benefit-cost ratio would be approximately 10.

We do not know what costs stakeholders might incur in adjusting to FAS, but we expect any such costs could be minimized by ERCOT providing enough lead time to avoid interfering with most power supply contracts.

Some stakeholders have raised concerns about FAS's dynamic requirements imposing ongoing risks on load serving entities. Dynamic requirements (which could be adopted under either FAS or an enhanced CAS) will create uncertainty about the required quantities of ancillary services. However, we expect that the market will develop ways to financially manage those risks more efficiently than maintaining non-dynamic requirements at sufficiently high levels to meet reliability criteria under all system conditions. (Again, our benefit-cost analysis assumed that even CAS incorporates dynamic requirements; if we had not, our net benefit estimates would have been higher.)

In summary, we found that FAS is good market design, and it offers economic benefits on the order of 10 times the implementation costs. FAS will also improve reliability and provide greater flexibility for meeting reliability needs as system conditions and resource capabilities evolve.

I. Introduction

ERCOT proposed to redesign its ancillary service market so it more efficiently and effectively supports reliability as system characteristics change. Inverter-based wind and solar generation is displacing traditional generation, reducing the inertia that has historically supported frequency following contingency events; and new technologies offer new ways to provide ancillary services.[2] ERCOT and stakeholders developed a detailed proposal for a "Future Ancillary Services" (FAS) design over the past two years. Now they are poised to decide whether to implement FAS. To help inform that decision, ERCOT retained The Brattle Group to assess whether the proposed changes would reduce the costs of ancillary services, creating economic benefits in addition to reliability and strategic benefits that ERCOT had identified.

We compared the costs of providing ancillary services under FAS to the current ancillary services (CAS) design, and we did so in three steps. First, we worked with ERCOT to determine the hourly AS requirements under each design, given various future system conditions. Second, we estimated the costs to meet the hourly requirements under each design. Finally, we assessed other benefits and costs qualitatively.

Our analysis relies on market simulations that ERCOT staff ran at our direction using the PLEXOS model, as well as analyses we conducted outside of the model. Part of our analysis considers cost savings resulting from admitting new technologies under FAS. We designed that part of the analysis to inform the net benefits of the FAS proposal, not to evaluate the overall cost or viability of the technologies themselves.

II. The FAS Proposal

A. Motivation for the FAS Proposal

On average ERCOT customers spend about $500 million per year on ancillary services. Needs and costs are likely to increase over time with the growth of inverter-based generation, such as wind and solar photovoltaics (PV). These intermittent renewable resources continue to expand

2 "667NPRR-01 Ancillary Service redesign 111814," ERCOT. November 8, 2014. Accessed Online. http://www.ercot.com/content/mktrules/issues/nprr/651-675/667/keydocs/667NPRR-01_Ancillary_Service_Redesign_111814.doc

and displace generation from traditional sources in ERCOT, which leads to lower net load and reduced system inertia to support frequency after contingency events. With lower inertia, more Responsive Reserves are needed to be prepared to maintain frequency. The prospect of increasing Responsive Reserve requirements raises the question of whether reserves can be procured more efficiently or from new technologies. (Regulation needs will increase as intermittent resources increase the variability of intra-interval net load, although FAS would not significantly change Regulation procurement from the current design, so we do not focus on Regulation in this study.)

Some specific areas for current ancillary services (CAS) improvement are:

- Responsive Reserve Service (RRS) must serve two different roles: the ability to ramp up (or curtail load) very quickly to support frequency in response to contingencies, and the ability to perform for at least an hour after a contingency to provide for frequency support (and during scarcity conditions when total supplies are very tight). This may discourage participation by resources that could provide one role efficiently but not the other.
- Load-RRS resources are all triggered at a frequency of 59.7 Hz. Many contingencies are not severe enough that all the Load-RRS would be required to restore system frequency; however, once those resources are deployed, they may not be prepared to be deployed again for 3 hours.
- Furthermore, under the current design there is no role for short-duration frequency reserves, and this likely deters some valuable resources from participating.
- Even some Load Resources might be deterred by the prospect of being deployed whenever frequency drops to 59.7 Hz, without other resources (that are more willing to be deployed) responding first and protecting them from having to deploy in smaller contingencies.
- CAS does not differentiate resources' ability to provide Gen-RRS. All are assumed to be able to provide 5% droop and are thus qualified to sell up to 20% of their maximum capacity or High Sustained Limit (HSL). However, some resources can provide lower droop and could therefore provide more than 20% of their capacity. And others do not perform as well and thus their provision of RRS should be limited to less than 20%. Relatedly, under CAS, there is no feedback between resource performance and RRS qualification, so resources have no incentive to improve.

- Load Resource participation in RRS varies unpredictably, and when it is low, Gen-RRS substitutes for it MW-for-MW. However, during low inertia conditions, Gen-RRS is less effective than Load-RRS, possibly leading to lower reliability unless an extra reserve cushion is introduced into RRS requirements. Removing the 50% limit on Load Resource provision of RRS would make these risks greater.
- Under many conditions, the Non-Spinning Reserve requirement is larger than necessary for reliability because requirements do not vary with system conditions.
- Regulation provisions may be too concentrated on a few resources because there is no limit on how much regulation a single resource can provide, except for its ramp rate.

Thus the motivation of the FAS proposal is to maintain or increase system reliability by: (1) enabling a broader range of resources to help meet system needs; (2) more finely tuning requirements to system conditions; and (3) using a procurement approach that better recognizes the relative effectiveness of different ancillary services and resources under different conditions. These efforts should also reduce the system costs of procuring reserves.

B. Service Specifications of FAS Compared to CAS

The FAS design seeks to address the issues identified above. Figure 1 below compares the CAS shortcomings to FAS features created to address those shortcomings.

Table 1: FAS Design Summary

CAS Shortcomings	FAS Features
RRS bundles frequency response with contingency response, hence a 1-hour requirement that bars batteries and other fast resources that would be valuable for frequency response	• **Separate out CR** as its own service, • **Introduce "FFR1" for** fast resources willing to be triggered at 59.8Hz and able to produce for 10 min then reset in 15 min • **Convert Load-RRS into "FFR2"** still at 59.7Hz
CAS does not fully recognize the higher value of FFR than PFR during low inertia: • 50% limit on Load-RRS may prevent low-cost, high-value resources from substituting for Gen; • When Load-RRS is lower than planned, MW-for-MW substitution with Gen-RRS would not be enough without a buffer, as described in Section III.B.	**Recognize greater value of FFR when inertia is low, through equivalency ratio** • Eliminate 50% Maximum on Load/FFR • Eliminate the need for a buffer
CAS does not differentiate resources' abilities and historic performance to provide RRS—all have a limit of 20% HSL	**The amount of PFR that a resource is allowed to carry is based on past performance**

CAS Shortcomings	FAS Features
Non-Spinning Reserve requirements are higher than needed under most system conditions	**Replace Non-Spinning Reserve with CR and SR that vary with system conditions (much less most of the time)**
Regulation provision may be too concentrated on a few resources with no limits on how much a single resource can provide (except own ramp rate)	**A single resource will be limited to carrying up to 25% of the system-wide regulation requirement** so there will always be at least four providers

Regulation reserves are used to balance short-term deviations from the net load forecast, due to changes in variable resource availability and demand. The definition of Regulation Up, Fast-Responding Regulation Up, Regulation Down, and Fast-Responding Regulation Down services remain mostly unchanged between CAS and FAS.

Frequency reserves are used to help the system to stabilize and arrest frequency excursions after contingency events, and to restore frequency, within normal bounds (59.97 Hz)

- In CAS, all frequency reserves are provided by a single product, Responsive Reserve Service, up to half of which can be served by Load Resources.
- FAS splits frequency reserves into three services (and five separate products), with the first three products providing initial frequency response, and the other two providing longer timescale Contingency Reserve to help restore frequency and relieve frequency response providers so they are prepared for the next event.
  - PFR, FFR1, and FFR2 are used to arrest frequency decay after contingencies or other significant events.
  - Additionally, PFR is used to limit frequency increases in cases of over-generation.
  - Contingency Reserve (CR) will be used to help restore frequency to within normal bounds (59.97 Hz) after a contingency. The deployment of CR replaces the deployed PFR/FFR providers to position the system to be able to respond should another contingency take place. The Contingency Reserve service includes two products: Contingency Reserve 1, which can be deployed by SCED, and Contingency Reserve 2, which must be manually deployed.

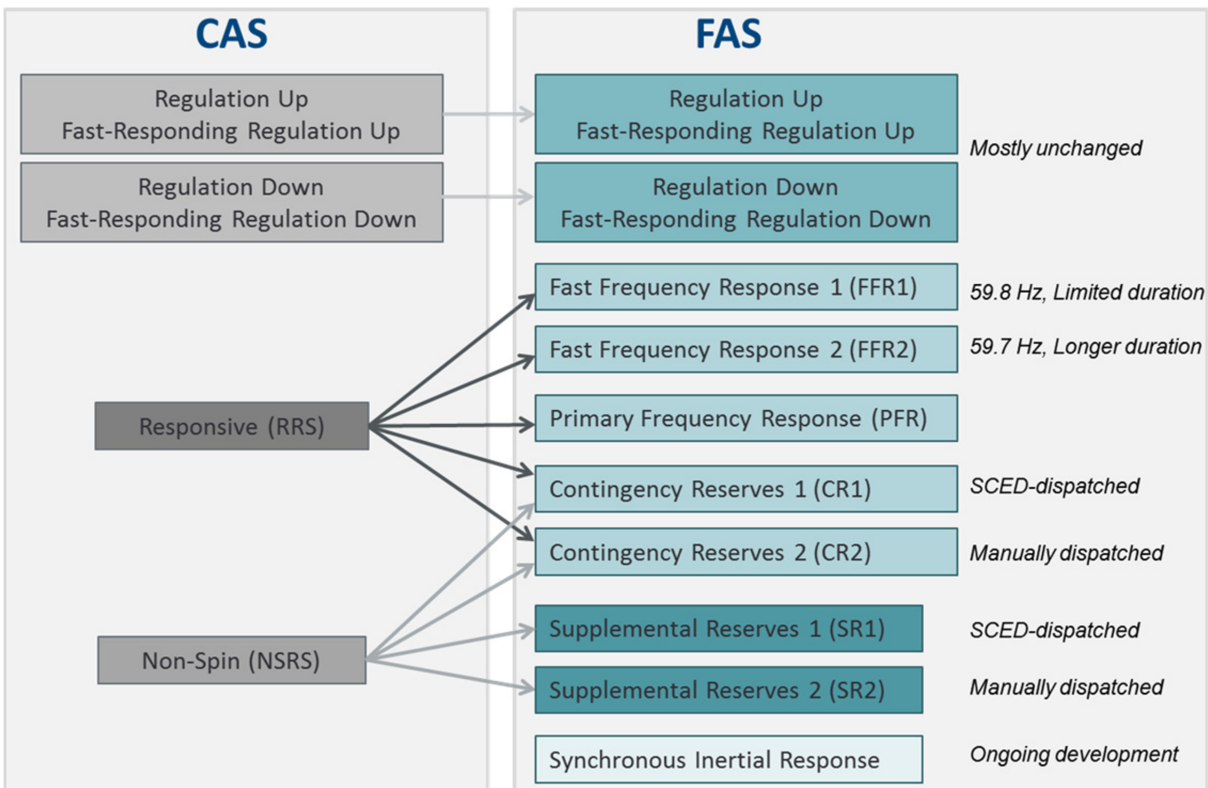
Replacement reserves are used to meet unexpected increases in net load resulting from forecast error and to replace the loss of generating capacity.

- In CAS replacement reserves are provided by Non-Spinning Reserve (NSRS)

- In FAS these replacement reserves will come from two separate products:
  - Supplemental Reserve 1, which are dispatched by SCED
  - Supplemental Reserve 2, which are manually dispatched.

Figure 1 illustrates the mapping of CAS products to FAS products. Note that all the reserve products in the FAS design are services (*e.g.*, Fast Frequency Response Service 1), but we have removed "service" from the FAS product names and abbreviations to help distinguish between CAS and FAS products and to make product names more distinct in our writing. We find the products are more difficult to distinguish when all product abbreviations end with "S."[3]

Figure 1: Mapping of Current and Proposed Future Ancillary Services



Note: Contingency Reserve has arrows from both Responsive Reserve and Non-Spinning Reserve because its capacity is released for dispatch based on frequency, similarly to Responsive Reserve in CAS,, but it also serves a replacement reserve role since its restoration of frequency to 60 Hz automatically unloads used PFR. Furthermore, Contingency Reserve could be served by many of the same resources currently providing Non-Spin.

3 In this report, "PFR" always refers to Primary Frequency Response Service. In other contexts, "PFR" could refer more broadly to the primary frequency response available from all generators, even those not being paid to provide Primary Frequency Response Service.

C. Qualification Criteria for Resources to Provide FAS products

For this study we assumed that all resources that are currently qualified for RRS would qualify for either FFR or PFR. Generators are assumed to provide PFR, and current load resources are assumed to provide FFR2. New load resources or new technologies, including batteries, could qualify for FFR1. Resources currently qualified for Non-Spinning Reserve (NSRS) are assumed to qualify for Contingency Reserve (CR) or Supplemental Reserve (SR), depending on their known capabilities. Units currently qualified as quick starts are modeled as offline CR resources in the model, while all other units currently qualified for NSRS are modeled with SR capability. New units, added as a result of generation expansion in the studied scenarios, are assumed to qualify for PFR as well as CR and SR from online status while limited by their ramping capability.

D. Other Procurement Assumptions

We focused on the cost differences between FAS and CAS by comparing the designs, with requirements under each design being sufficient to meet reliability criteria. CAS has already evolved from a fixed RRS requirement to one that varies with anticipated system conditions by estimating AS needs in October for the following year. However, our study assumes that CAS determines AS requirements on a day-ahead basis to account for expected inertia and availability of load resources in order to make CAS assumptions consistent with our assumptions for FAS. Absent this assumption about tuning CAS procurements to system conditions, the efficiencies offered by FAS would increase.

III. Analysis of AS Quantities Needed under Each Design

A. Approach

The amount of frequency response needed depends on system inertia. Inertia reflects the amount of spinning mass that determines frequency decay following a contingency. Inertia is lowest during periods of low net load (*i.e.*, load minus renewable generation), when less thermal generation capacity with rotating mass is committed. With less inertia, frequency decays faster following contingencies, and more responsive reserves are needed to maintain frequency.

For the purposes of this study, ERCOT staff determined the requirements for both designs based on the methodologies they described to the Technical Advisory Committee in July 2015.[4] The CAS requirements are determined as follows:

- **Responsive reserve** requirements are determined using dynamic simulations, with the objective of limiting the frequency nadir to 59.4 Hz for the loss of largest two units (2,750 MW). ERCOT develops 12 system stability cases representing a range of inertia conditions. For each hour, ERCOT sets the total responsive requirements based on the system stability case that is closest to the expected inertia amount in that hour. The final responsive requirement is adjusted based on equivalency ratio, the 50% load resource limit, and a Minimum Gen-RRS limit. The Minimum Gen-RRS limit is set based on NERC reliability requirements and must be met in every hour of the year. In our analysis, we assume total responsive requirements increase when expected Load-RRS participation falls below 50%, although ERCOT currently sets requirements based on an assumption of a constant 50% Load-RRS participation. This assumption allowed us to compare CAS to FAS on a roughly equivalent basis in terms of reliability.
- **Regulation reserves** requirements are determined to meet the 98.8th percentile of the 5-minute change in net load. They vary by month-hour based on load and generation patterns.
- **Non-Spinning Reserve** requirements are set for 6 four-hour blocks for each month by analyzing the quantity necessary to meet the 95th percentile of net load forecast error minus the corresponding Regulation-Up requirement. The maximum Non-Spinning Reserve requirement in any hour is capped at 2,000 MW, and the minimum requirement during peak hours is 1,375 MW.

FAS's requirements differ from CAS's as follows:

- **PFR/FFR** requirements are determined using the same dynamic simulations as in CAS. However, FAS removes the 50% limit on Load participation (as FFR), admits other FFR resources, and counts the inertia-dependent equivalency ratio recognizing FFR's greater effectiveness in arresting frequency decay under low inertia conditions. ERCOT will define the final requirement in PFR terms and the equivalency ratio between PFR and

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[4] ERCOT, "FAST CBA AS Quantities," PowerPoint presented at an ERCOT TAC Meeting. Austin, Texas, July 30, 2015. Accessed at http://www.ercot.com/calendar/2015/7/30/31901-TAC.

FFR. This definition ensures that reliability requirements are always met independent of the cleared FFR/PFR mix. Furthermore, there is no need to adjust requirements beforehand based on expected participation of resources providing FFR. The final requirement will have a Minimum PFR limit, similar to the Minimum Gen-RRS limit in CAS, based on NERC requirements.

- **Regulation** requirements are the same as under CAS.
- **Contingency Reserve** (CR) requirements are determined using the same 12 system stability cases used to determine PFR/FFR requirements. ERCOT matches hourly expected system inertia conditions to the appropriate system stability case to determine the CR requirement for that hour. The CR requirement has a floor of 1375 MW during peak hours.
- **Supplemental Reserve** (SR) serves as a placeholder to fill any additional needs that may arise, but ERCOT has not found any need for Supplemental Reserve under anticipated system conditions.

To translate the above rules into hourly requirements that are amenable to cost-benefit analysis, ERCOT staff conducted hourly simulations using the PLEXOS unit commitment and dispatch model. They used the model to derive the hourly system inertia and associated AS requirements through an iterative process since requirements affect unit commitment and inertia. This process was applied to three future scenarios that ERCOT and stakeholders had agreed to include in our study:

- A 2016 "Current Trends" (CT) scenario that reflects expected market and system conditions for next year;
- A 2024 "Current Trends" scenario based on ERCOT's Long-Term System Assessment (LTSA) scenario developed in 2013, but with 3,977 MW of additional wind generation (21,528 MW total installed) that had a signed interconnection agreement and financial security posted by May 2015, and 2,200 MW additional gas-fired generation to meet a reserve margin consistent with the "economic equilibrium" reserve margin from Brattle's EORM study.[5] We also analyzed a variant of this scenario in which new technologies respond to new opportunities FAS would offer, although the requirements themselves did not differ from the case without new technology.

5 See Appendix Section I.B.1.a for further explanation

- A 2024 "Stringent Environmental" scenario from the same LTSA, with 28,204 MW of installed wind, 9,246 MW of installed solar PV capacity, and ~1,000 MW of coal retirements relative to the 2024 Current Trends scenario. This case had a $45 per ton price of CO_2 allowances.

We found, somewhat surprisingly, that the Stringent Environmental scenario did not have the lower system inertia and correspondingly higher reserve requirements that ERCOT and stakeholders had originally expected when choosing this scenario as a stress case. On average the Stringent Environmental case had *higher* inertia because the $45/ton carbon price (an assumption from the LTSA) caused combined-cycle generation to displace coal for baseload duty, and combined-cycles have higher inertia constants than coal units of the same MVA rating. We chose not to evaluate the Stringent Environmental case further since it was not the anticipated stress case. Table 2 below compares the net load and inertia levels between the three cases.

Table 2: Net Load and Inertia

Measurement		2016	2024 CT	2024 SE
Load (MW)	Average	45,167	51,393	50,828
Renewable Gen (MW)	Average	6,959	9,419	13,982
Net Load (MW)	Average	38,209	41,974	36,907
	Max	73,450	77,487	71,908
	Min	14,616	17,553	11,457
Inertia (MW-Seconds)	Average	211,129	219,076	235,132
	Max	379,334	407,725	376,781
	Min	113,692	107,423	89,887

The resulting requirements for CAS and FAS products in the Current Trends scenario are summarized in Table 3 on an annual average basis (note: the study was conducted on an hourly basis with requirements that vary hourly). As the table indicates, FAS reduces AS procurement in two ways: (1) reduction in Non-Spinning Reserve requirements, net of the increase to Contingency Reserve; (2) reduction in Responsive Reserves, resulting from incorporating the equivalency ratio into market clearing and removing the 50% limit on Load Resource provision of RRS that exists under CAS. Detailed descriptions of these quantities for both PFR and CR/NSRS procurement are provided in the sections below.

Table 3: Summary of Reductions in AS Procurements

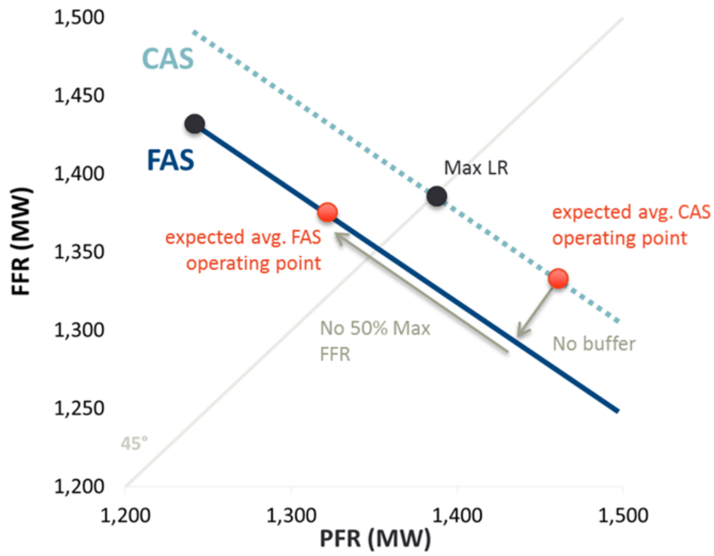
	CAS	FAS	Savings	Comment
Procure Less PFR by recognizing equivalency ratios and allowing more FFR (incl. FFR1)				
2016 Avg MW	1,468	1,329	**140**	Allow > 50% FFR; no need for buffer. Increase FFR by 24 MW on average.
2024 Avg MW	1,453	1,325	**129**	Slightly less than 2016 due to higher net load & inertia. Increase FFR by 13 MW on average.
2024 Avg MW *w/new tech*	1,453	1,267	**186**	62 MW assumed new batteries reduce avg. PFR by 57 MW; small because residual avg. FFR opportunity (after load resources) is only 62 MW and highly variable
Replace Non-Spinning Reserve with less CR and SR (products comparable because of common NSRS/CR/SR duties and supply base)				
2016 Avg MW	1,931	1,175	**756**	FAS adapts requirements to system conditions; additionally CR is determined based on frequency obligations, and Non-Spinning Reserve is determined to meet deviations in net load.
2024 Avg MW	2,000	1,210	**790**	See above (note: assumptions about new tech do not affect CR)

B. Reductions in PFR Quantities

FAS reduces PFR procurement quantities compared with Gen-RRS by providing more efficient FFR/PFR substitution and allowing more FFR participation by removing the 50% limit on Load Resource provision of RRS. FAS has more efficient FFR/PFR substitution because it explicitly incorporates the equivalency ratio in FAS's market clearing engine. Under the system conditions we modeled, the equivalency ratio varied from 1-to-1 to 2.2-to-1 as inertia decreased.

As a result of the relieved limit and equivalency ratio, PFR reductions are substantial, but still only 9% on average. The PFR reductions are limited by the Minimum PFR constraint as FFR participation, which is already near maximum, increases. Figure 2 below illustrates how FAS allows for more FFR procurement and less PFR than CAS, based on annual average requirements for 2016.

Figure 2: Frequency Response in 2016: FAS vs. CAS



Two main improvements of the PFR FAS design are illustrated in the above chart: (1) recognizing the FFR/PFR equivalency ratio in the market clearing engine allows PFR to adequately substitute for any FFR shortfalls and maintain reliability without the "buffer" needed under CAS, as explained below; and (2) removing the 50% limit on Load Resources participation in frequency reserves allows more FFR to substitute for PFR that is more costly and less effective, when the equivalency ratio is more than 1.

The "buffer" noted above is an increased RRS requirement we assumed CAS would need in order to maintain reliability when Load-RRS is unexpectedly low. CAS substitutes MW-for-MW between Load Resources and Generation even during system conditions when the equivalency ratio exceeds 1; CAS therefore does not recognize when Load-RRS is more effective than Gen-RRS. To calculate the buffer, we assumed average load participation based on 2014 average load participation rates (as percent of maximum allowed Load-RRS) for each hour-month; and we treated variation within each hour-month as a random variable. We then calculated the amount of additional RRS buffer needed to meet needs 95% of the time. On average across all hour-months in 2016, the buffer was 42 MW, but varied from 0 to 282 MW. Adding the buffer increases assumed RRS requirements relative to the tightly-calculated requirements based on day-ahead inertia and treating the expected load participation for each hour-month as guaranteed. (Note: ERCOT may not be explicitly including a buffer in its current CAS requirements nor does it determine CAS requirements on a daily basis; we designed our study so we could compare the costs of two designs that are nearly-equivalent in terms of reliability. In

Section VI.B we discuss the implicit buffer built into CAS requirements based on the year-ahead forecasts.)

FAS will allow PFR and FFR to substitute for each other according to the equivalency ratio and would obviate the need for a buffer. In 2016, eliminating the buffer reduces expected Gen-RRS procurements by 21 MW on average; in 2024, eliminating the buffer reduces expected Gen-RRS procurement by 19 MW on average. This is a non-trivial effect but not the dominant source of savings. The dominant sources are from eliminating the 50% limit on Load Resource participation, which increases the expected amount of FFR and reduces PFR by another 119 MW on average in 2016 and 110 MW in 2024.[6]

Originally, we hypothesized that there would be large benefits in FAS from substituting new technology in place of traditional generation. However, the opportunity for FFR beyond existing load resources was modest because simulated inertia actually increases by 2024, resulting in lesser requirements for responsive reserves overall. Existing load resources are sufficient to meet most of the FFR opportunity, leaving little incremental opportunity for new technology. FFR opportunity for new technology could be greater if load resource participation decreased. Moreover, participation by new technologies would certainly not be limited to the incremental FFR opportunity we are ascribing to FAS. New technologies may also provide energy, regulation, and other services.

Figure 3, below, shows the average reduction in the PFR requirement in FAS compared to Gen-RRS requirement in CAS for 2016. The reduction in the requirement is greatest during off-peak periods and during winter and shoulder seasons.

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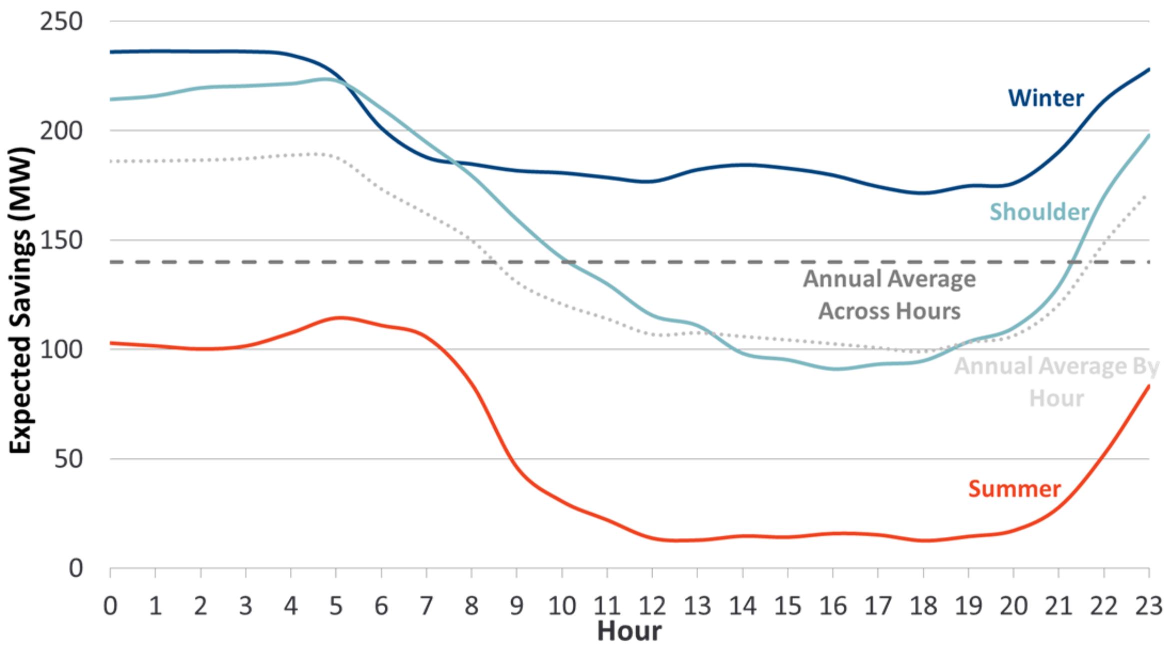
6 The reduction in PFR MW presented here relate to our assumptions on FFR resource availability presented in the Appendix I.B.1.f

Figure 3: PFR Savings under FAS Relative to Gen-RRS under CAS in 2016 (Average MW by Hour)



It is notable that PFR procurements decrease substantially more than FFR procurements increase (*i.e.*, a PFR reduction of 140 MW and a FFR increase of only 24 MW on average in 2016, as shown above in Table 3). This imbalance is caused by the buffer we assumed in CAS, the Minimum PFR constraint, and the 50% Load-RRS rule. In our CAS requirements, the buffer increases the necessary amount of RRS. FAS does not need such a buffer, which helps reduce PFR procurement but also reduces FFR procurement. When we isolate the effect of the buffer we find that in the 79% of hours during which the Minimum PFR constraint is not binding, FAS increases the availability of FFR by the same quantity (based on the equivalency ratio) by which it decreases the PFR requirement. However, in the 21% of hours that the Minimum PFR constraint binds, both the PFR and FFR amounts decrease under FAS. Under CAS, load is always allowed to provide 50% of the RRS requirement. Therefore, in hours when the Minimum Gen-RRS constraint binds and the total RRS requirement is less than twice that minimum, the final requirement is increased, and additional Load Resources are allowed to meet half of that increase[7]. Under the FAS design, however, in hours that the Minimum PFR constraint is binding

7 Consider an RRS Requirement of 2,240 MW and Min Gen-RRS requirement of 1,240 MW in CAS. The total RRS requirement increases to 2,480 MW to meet the Min Gen-RRS requirement and the allowed 50% participation of Load-RRS. In FAS, the total PFR/FFR requirement remains at 2,240 MW, the PFR requirement would be 1,240 MW, and the FFR requirement would be 1,000 MW. This example is for an hour with an equivalency ratio of 1, for simplicity.

and the total requirement is low, the FFR requirement will simply be less than the PFR requirement.

C. Reductions in Non-Spinning Reserve/Contingency Reserve Quantities

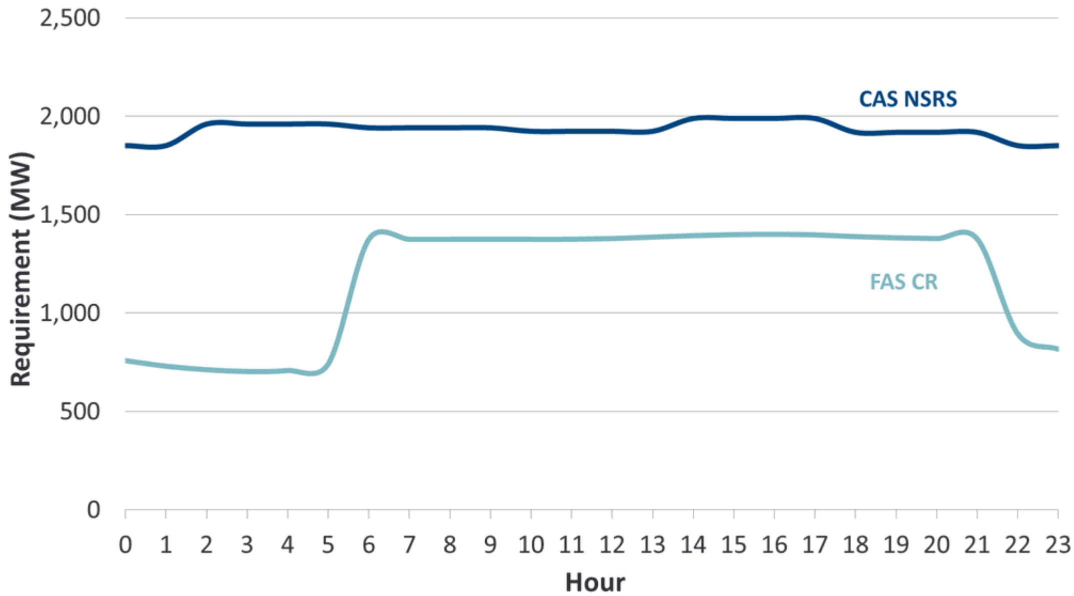
The second significant portion of our savings comes from reduced Contingency Reserve (CR) needs in FAS relative to Non-Spinning Reserve (NSRS) needs in CAS. We compare NSRS and CR because they provide similar services and are provided by similar resources:

- Both help meet unanticipated energy needs that arise when net load exceeds forecasts.
- Following contingencies, both provide energy to allow frequency response providers to back down so they are ready for the next contingency.
- Both are largely provided by 10-min startup resources—in FAS this is a formal requirement and in CAS it historically has been true.

As discussed above, Non-Spinning Reserve requirements are set to cover increases in net load due to forecast errors and to replace responsive reserves when deployed. In peak hours, the requirement is subject to a minimum of 1,375 MW to cover against loss of the single largest unit. Similarly, FAS Contingency Reserve requirements are based on the capacity necessary to restore the system to normal frequency and relieve PFR/FFR resources. Additionally, Contingency Reserve requirements are determined for every individual hour of the month (potentially 744 different values), whereas Non-Spinning Reserve requirements are set as one daily shape built in 6 four-hour blocks applied to every day of the month (only 6 potential values). If there is one hour with a large expected net load forecast error, it will increase the total procurement of Non-Spinning Reserve for the month and have a significant impact on the average procurement for the year. Under FAS, one hour with high inertia and high Contingency Reserve requirements will have an insignificant impact on average procurement.

The system is able to maintain reliability overnight with smaller quantities of Contingency Reserve because system inertia is low and frequency recovers faster than during high inertia conditions. Thus, less Contingency Reserve is needed to bring frequency back to 60 Hz. Under FAS, ERCOT can account for that while determining amounts of replacement reserves. Figure 4 below shows how the FAS Contingency Reserve requirements compare to the CAS Non-Spinning Reserve requirements in 2016; similar trends are seen in 2024.[8]

Figure 4: CAS NSRS and FAS CR Requirements in 2016 (Average MW by Hour)



IV. Economic Benefits

A. Summary

One would expect that FAS would reduce the cost of ancillary services due to its effects on both demand and supply. On the demand side, it reduces the quantities of comparable services by fine-tuning needs to system conditions and provides a mechanism to recognize (during the procurement process) the relative effectiveness of the ancillary services. On the supply side, it expands the amount of resources able to compete and recognizes resources' special capabilities—a hallmark of good market design.

To quantify the economic savings, we compared the cost to provide each type of ancillary service under FAS vs. CAS. One high-level way to estimate benefits would be to multiply the reductions in quantities by typical prices for the services, since prices reflect marginal costs. For example,

8 Note that reductions in the CAS Non-Spinning Reserve (NSRS) requirement were recently approved by the ERCOT board. While FAS CR procurement is still lower than these recently approved NSRS quantities, the lowered NSRS requirement will reduce benefits of adopting FAS. The reductions are explained below in Section V.

the average reduction in PFR procurement was 140 MW in 2016; multiplying by the $14.16/MW average price in 2014 suggests approximately $17 million of annual benefits. Similarly, multiplying the 756 MW average CR/NSRS savings in 2016 by the $5.48/MW average price in 2014 suggests approximately $36 million in annual benefits.

However, we developed a more detailed and granular benefits estimate accounting for unit commitment and dispatch and potential changes in future market conditions. We estimated the economic savings from the reduction in AS quantities, analyzing two separate and additive components of the production cost of providing ancillary services: *day-ahead energy opportunity costs*, which reflect the cost of committing and holding (often inframarginal) capacity in reserves, considering the expected value of real-time prices across all possible real-time system conditions; and *real-time option value foregone*, considering the volatility of real-time prices around the expected value. It reflects the cost of holding reserves and losing the option to change operations as different real-time conditions are realized. The real-time cost also accounts for the possibility of committed providers experiencing a forced outage and having to replace their capacity with other resources on short notice.

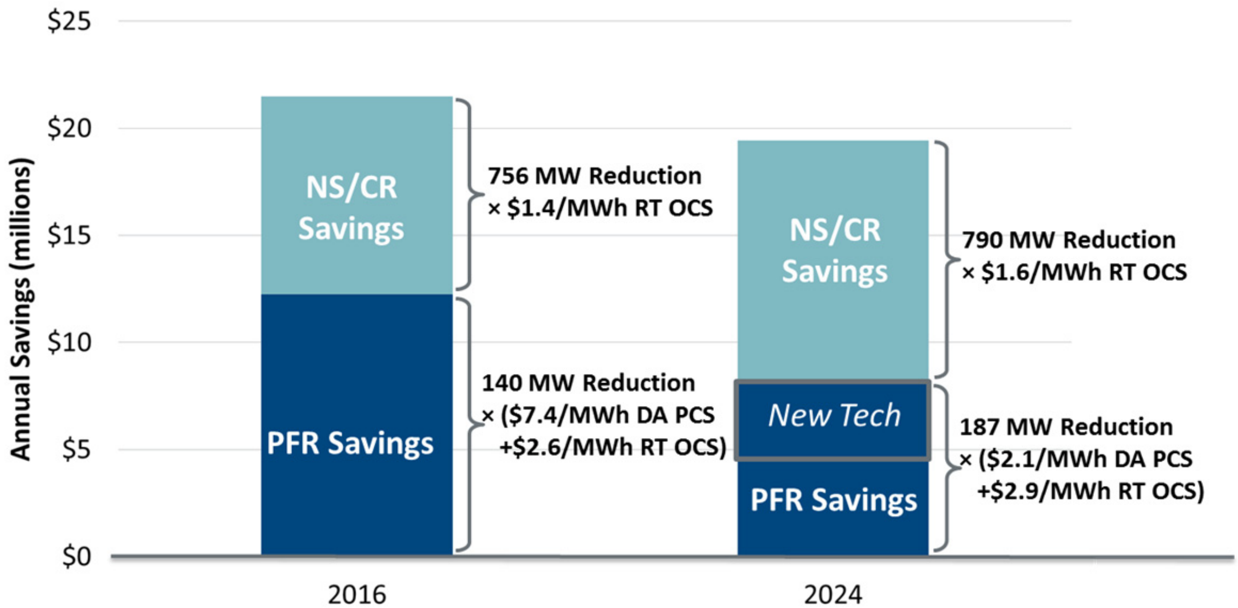
To help estimate day-ahead production cost savings, ERCOT staff ran the PLEXOS simulation model at our direction, for each of the scenarios described in the appendix. We found that FAS's reduced PFR procurement—due to tighter requirements and substitution by FFR—reduces production costs by allowing fewer units to be committed and by allowing those that are committed to be dispatched more efficiently. FAS's reduction in contingency reserve—with substantially less Contingency Reserve than Non-Spinning Reserve under CAS—has little impact on unit commitment and dispatch, since most of these awards go to offline resources.

PLEXOS does not account for the real-time opportunity costs of providing ancillary services because it does not model the unexpected events that occur in real time, so we analyzed those costs outside of the model based on historical capacity offers. We found that both the reduced PFR vs. Gen-RRS procurements and the reduced Contingency Reserve vs. Non-Spinning Reserve procurements lead to reduced real-time opportunity costs.

Day-ahead production cost savings and real-time opportunity cost savings estimated for FAS are summarized below in Figure 5, corresponding to FAS and CAS procurement quantities described in Section III above. We describe the quantity reductions and economic savings under alternative assumptions regarding CAS and FAS in Section V below.

Note that Figure 5 includes only the benefits we were able to quantify. FAS will likely provide other economic and reliability improvements, which we describe qualitatively in Section IV.D below.

Figure 5: Quantified Annual Benefits



We did not include changes in fixed and capital costs, even in the new technology scenario, since those costs are uncertain. We believe they are likely to be small on a net basis with new technology displacing conventional technology. For example, a 100 MW battery could displace more than 100 MW of conventional technology providing PFR, depending on the equivalency ratio. Therefore, the 100 MW would not have to be installed, or it could be liberated to provide energy or other products and displace a different 100 MW. The net incremental costs would be 100 MW × (levelized capital and fixed cost of conventional generation – levelized and fixed cost of a battery) + production cost impact of having 100 MW battery instead of conventional generation. However, the uncertainty regarding a battery's capital cost exceeds any production cost impacts. We therefore ignore incremental capital costs in a plausible scenario where new technology does enter under FAS, recognizing that it would not enter if its revenues from selling ancillary services (and possibly energy) did not justify its capital cost.

B. Day-Ahead Production Cost Savings

At our direction, ERCOT staff ran the PLEXOS production cost model. The PLEXOS model minimizes the total system dispatch cost while meeting all system requirements. We analyzed day-ahead production cost savings by building cases that varied the ancillary service requirements while holding all other inputs and assumptions constant. For each scenario, we ran one case with CAS reserve requirements and one with FAS reserve requirements. We used the difference in production costs to quantify day-ahead benefits of FAS. We analyzed the changes in unit dispatch and commitment between cases to ensure that the production cost savings were in line with the changes in reserve requirements between the cases. We present more details on PLEXOS modeling assumptions in the appendix.

In 2016, FAS's reduced PFR needs save $9.1 million per year in day-ahead production costs; $1.8 million of which are from avoided startup costs. The remaining savings are from dispatching lower marginal cost units for energy that are now providing less capacity for reserves. The savings occur primarily during the winter overnight hours when reduced PFR procurement allows some combined-cycle units to be de-committed and coal units to ramp up to their maximum capacity. Under CAS, combined-cycle units had to be committed at minimum generation in order for the system to procure enough reserves.

In 2024, FAS's reduction in PFR procurement decreases simulated production costs by $1.2 million per year without new technologies and $3.4 million per year with new technologies; only $248 thousand of which are from avoided start-up costs. Unlike in the 2016 cases, coal units are fully dispatched to serve baseload duty due to the increase in net load in the 2024 case. The model increases the dispatch of more efficient gas units and decreases the usage (both commitment and dispatch) of less efficient gas units. The marginal cost difference between two gas units is much smaller than the marginal cost difference between a coal and a gas unit, which results in lower FAS savings in our 2024 cases.

Unlike frequency response services, replacement reserves (*i.e.*, CR, SR, and NSRS) have little effect on day-ahead production costs. Since these products can be provided by offline resources, their procurement has little effect on unit commitment and dispatch. They do not cause units to come online nor do they hold back online capacity for reserves (as evidenced by the very low shadow price on those constraints in PLEXOS). Consequently, PLEXOS shows a zero price for these products in almost all hours and finds little value in FAS's reduced NSRS/CR procurement. Therefore, we attribute no day-ahead production cost savings to NSRS/CR reductions in FAS.

C. Real-Time Opportunity Cost Savings

PLEXOS informs the Day-Ahead (DA) opportunity cost savings by estimating the reduction in overall production costs associated with modified and reduced ancillary service needs. However, as mentioned above, PLEXOS does not estimate the real-time (RT) optionality foregone by committing capacity for reserves because it does not model unexpected changes that occur in real time. This section describes the foregone real-time optionality concept, our analysis of resources' real-time opportunity costs to provide AS in 2014, and finally our application of those opportunity costs (on a per-MW-per-hour basis) to the quantities procured in our future AS scenarios. The appendix provides additional details of the real-time opportunity analysis.

1. Concept

Units committing capacity for reserves incur real-time opportunity costs beyond the day-ahead opportunity costs that correspond to expected real-time prices. Capacity reserved for the "up" services is restricted from generating energy no matter how high real-time prices may become (though Non-Spinning reserve capacity is allowed to sell energy when real-time prices exceed $75/MWh). This capacity is also prevented from turning off if real-time prices become very low since the unit must remain spinning (this means the unit must remain at or above its minimum load, except for units providing Non-Spinning reserves, which need not be spinning). Capacity providing Regulation Down is similarly restricted, being obliged to generate energy no matter how low real-time prices may become. These restrictions reduce the option value capacity would otherwise have and thus represent additional costs of providing ancillary services.

To illustrate, consider a marginal unit in the day-ahead energy market that also offers to provide Regulation Up. Assume that the day-ahead energy market clears at $50/MWh and that the real-time energy market clears at $52/MWh. If the marginal unit commits capacity in the day-ahead market to provide Regulation Up, the unit foregoes $2/MWh of net energy revenue. While this example applies to the foregone optionality of providing Regulation Up, providing other ancillary services also involves opportunity costs. Table 4 presents a matrix of option values for a hypothetical unit that considers offering capacity in the ancillary services markets.

Table 4: Real-Time Optional Value Matrix

Examples of a Marginal Energy Provider Providing Various Ancillary Services

AS Provider Considerations

Unit Costs are $50/MWh

Day-Ahead Settlement

Energy Price $/MWh	$50
DA Opportunity Cost based on expected RT price (before considering RT volatility and associated optionality) $/MWh	$0

Real-Time Option Value Foregone by Providing AS

Probability	Potential RT Prices		Regulation Down [1]	Regulation Up/RRS [2]	Non-Spin [3]
1%	$80	**Unit Desire:**	Turn up to gain $30	Turn up to gain $30	Turn up to gain $30
		Prevented by AS?	No	Yes	No
		Option Value Foregone:	$0	$30	$0
49%	$52	**Unit Desire:**	Turn up to gain $2	Turn up to gain $2	Turn up to gain $2
		Prevented by AS?	No	Yes	Yes
		Option Value Foregone:	$0	$2	$2
49%	$48	**Unit Desire:**	Turn down to gain $2	Turn down to gain $2	Turn down to gain $2
		Prevented by AS?	Yes	No, until at min load	No
		Option Value Foregone:	$2	$0	$0
1%	$20	**Unit Desire:**	Turn down to gain $30	Turn down to gain $30	Turn down to gain $30
		Prevented by AS?	Yes	No, until at min load	No
		Option Value Foregone:	$30	$0	$0
		Expected Foregone Option Value:[4]	**$1.28**	**$1.28**	**$0.98**

1: Capacity providing Reg Down must generate energy even if the energy price is low in real time.

2: Capacity providing Reg Up or RRS is restricted from providing energy even if the energy price is high in real time. Providing these services can also prevent a unit from optimizing against low real-time prices: since it must remain spinning, the unit cannot turn down below minimum load. This possibility increases the expected foregone option value beyond the $1.28/MWh shown in this simplified example which ignores minimum load constraints.

3: Capacity providing Non-Spin is restricted from providing energy unless the real-time price exceeds $75/MWh.

4: The Expected Foregone Option Value is given by the probability-weighted average of the Real-Time Option Values across the four real-time price scenarios. This value is additive to the day-ahead value we calculate in PLEXOS, which does not account for real-time volatility and optionality. It represents the capacity offer that a market participant would submit so the ERCOT day-ahead clearing engine accounts for real-time optionality.

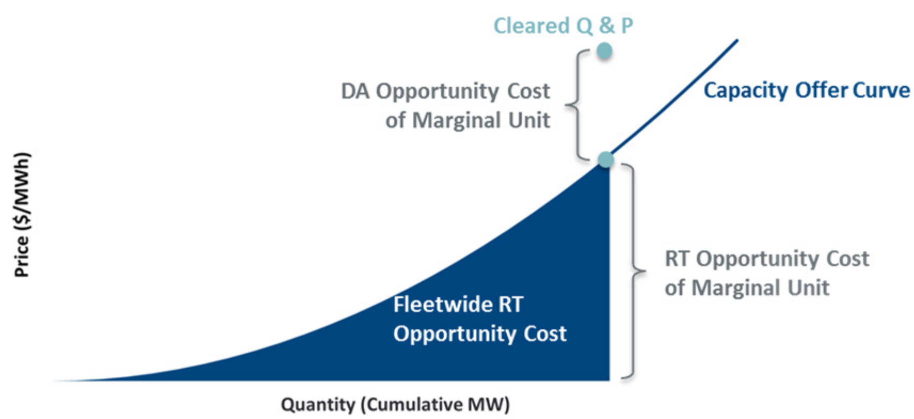
While this matrix simplifies the tradeoff between AS market participation and real-time optionality, it gives an intuitive notion of the optionality foregone by selling into the AS market. We assume that these opportunity costs affect the offering behavior of AS providers in ERCOT and therefore the offers represent a real cost to system operations. In Section IV.C.2, we describe our use of generators' capacity offers into the AS markets to estimate the real-time opportunity costs for the entire ERCOT fleet.

2. Analysis of Historical Real-Time Opportunity Costs

To inform our estimate of the real-time opportunity cost savings due to FAS implementation, we analyzed historical AS offers and associated real-time opportunity costs. We chose 2014 as a representative year and obtained AS capacity offers for 2014 from ERCOT. We assumed that these offers were competitive and represented individual units' foregone real-time energy opportunity costs. Then, we calculated and summed the opportunity costs that each individual unit incurred to provide AS in 2014 to arrive at the total fleet-wide opportunity costs.

The data ERCOT provided included capacity offer information for the RRS and NSRS markets for each hour of each day in 2014, and we sorted these capacity offers by price to create RRS and NSRS offer curves for all 8,760 hours in the year.[9] We estimated the 2014 fleet-wide real-time opportunity costs by calculating the area under these offer curves. For every hour, we determined the marginal unit by comparing the settlement price of a given hour to an individual unit's offer on the offer curve after removing the DA energy opportunity costs from the settlement price.[10] We used this marginal unit to help calculate the area under the curve. This method is illustrated below in Figure 6.

Figure 6: Method for Calculating Fleet-wide RT Opportunity Cost from Capacity Offers



We then used these areas to calculate average RT opportunity costs (in $/MWh) for a given hour by dividing the total fleet-wide costs by the AS quantity procured in that hour. We calculate the average cost instead of the marginal cost to be conservative. We chose to use more conservative calculation of savings because of the complexity and uncertainty of future offering behavior as well as the interplay between units offering into multiple ERCOT markets. An illustrative difference in the average cost avoidance compared to the marginal cost avoidance is shown in Figure 7.

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9 Due to limited changes in the regulation markets between CAS and FAS, they were excluded from this analysis.

10 We find the marginal provider of AS because we want to consider only opportunity costs for units that clear the AS market of interest.

Figure 7: Illustration of Marginal Cost Avoidance vs. Average Cost Avoidance

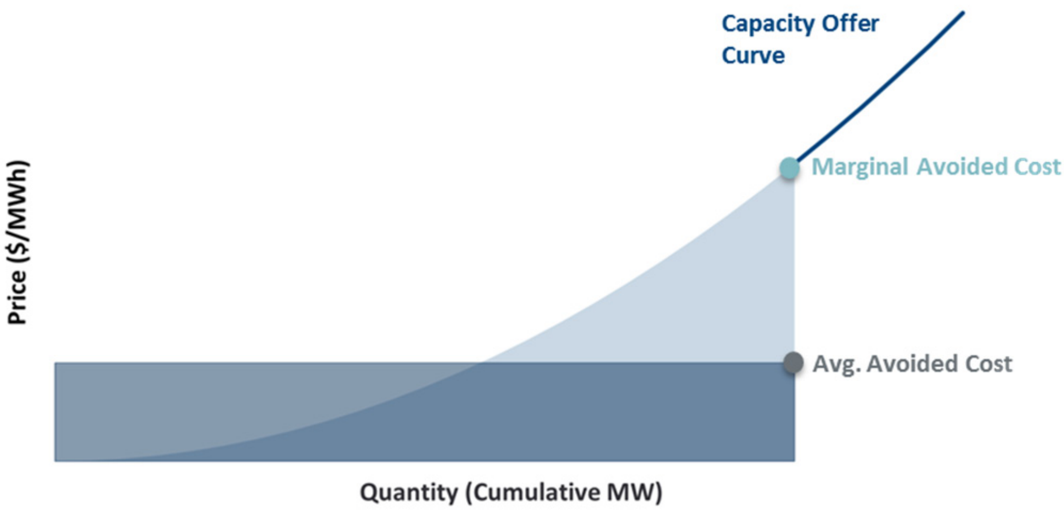

Table 5 below summarizes the results of our 2014 analysis. The estimated real-time average fleet-wide opportunity costs shown in row [8] were used to scale up the fleet-wide real-time opportunity cost for future cases.[11] As discussed in Section IV.C.3, we apply these average costs to the AS quantity changes in CAS and FAS. The average costs we calculated from the offer curves, equal to $2.41 per MW of reserves, are one quarter of the real-time component of average historical clearing price, $9.90, which is a marginal value. As noted above, we used the average real-time opportunity cost rather than the marginal cost due to the uncertainties inherent in these capacity offers.

[11] The average RT opportunity cost shown in row [8] represents an average yearly estimate. In our analysis of future CAS and FAS cases, we increase the granularity of our calculation of savings by estimating average month-hour real-time opportunity costs for Gen-RRS and NSRS.

Table 5: Estimated RT Opportunity Cost from 2014

2014 Reference Case		Gen RRS	NS
Actual Avg. Quantity (MW)	[1]	1,416	1,377
Actual Total Quantity (MWh)	[2]	12,398,856	12,060,630
Actual Payments ($thousands)	[3]	$178,671	$67,143
Actual Avg. Price ($/MWh)	[4]	$14.16	$5.48
Est. DA Opportunity Component ($/MWh)	[5]	$4.26	$0.01
Est. RT Opportunity Component ($/MWh)	[6]	$9.90	$5.47
Estimated RT Fleetwide Oppy Cost ($thousands)	[7]	$29,936	$18,160
Estimated Avg. RT Fleetwide Oppy Cost ($/MWh)	[8]	$2.41	$1.51

Sources and Notes:
[1] = Average quantity procured over all hours in 2014
[2] = Total quantity procured over all hours in 2014
[3] = Sum product of settle price and settle quantity for all hours in 2014
[4] = Average settle price in 2014
[5] = Estimated Day Ahead opportunity cost using results from 2016 CAS PLEXOS results
[6] = [4] – [5]
[7] = Area under the hourly offer curves. Does not include DA Opportunity costs from PLEXOS
[8] = [7] / [2] (Note: less than RTOC price because average cost over the fleet is less than that of the marginal price)

3. Implementation in this Study

To estimate the real-time opportunity cost savings in future years, we scale 2014 average real-time opportunity costs based on future CAS and FAS quantities procured. This approach makes the assumption that opportunity costs are invariant as system conditions and AS frameworks change. Results of this analysis are shown below in Table 6. We estimate real-time opportunity cost savings for PFR of $3.2 million in 2016 and $3.3 million in 2024. For NSRS/CR savings, we estimate $9.2 million in 2016 and $11.2 million in 2024.

Table 6: Reductions in RT Opportunity Cost

Case	Metric	RRS			Non-Spin		
		CAS	FAS	Savings	CAS	FAS	Savings
2016	Avg. Quantity (MW)	1,468	1,329	140	1,931	1,175	756
	Total Fleetwide RT Oppy Cost ($Millions)	$32.3	$29.2	$3.2	$26.5	$17.2	$9.2
	Avg. RT Opportunity Cost ($/MWh)	$2.5	$2.5	$0.0	$1.6	$1.7	-$0.1
2024	Avg. Quantity (MW)	1,453	1,325	129	2,000	1,210	790
	Total Fleetwide RT Oppy Cost ($Millions)	$37.4	$34.1	$3.3	$32.0	$20.8	$11.2
	Avg. RT Opportunity Cost ($/MWh)	$2.9	$2.9	$0.0	$1.8	$2.0	-$0.1
2024 w/ NT	Avg. Quantity (MW)	1,453	1,267	187	2,000	1,210	790
	Total Fleetwide RT Oppy Cost ($Millions)	$37.4	$32.6	$4.8	$32.0	$20.8	$11.2
	Avg. RT Opportunity Cost ($/MWh)	$2.9	$2.9	$0.0	$1.8	$2.0	-$0.1

Future savings could be higher or lower depending on how technology development affects real-time volatility. Volatility may increase with higher wind and solar penetration or may decrease with higher storage penetration, more active demand participation in real-time markets, or with ERCOT's "Multi-Interval Real Time Market (MIRTM)" initiative. Furthermore, there is considerable uncertainty surrounding the applicability of the offer data we used and how much the capacity offers may change in the future.

However, as mentioned above, we are confident that our use of average cost savings instead of marginal cost savings conservatively estimates the real-time opportunity cost. We tested other methods of cost calculation and showed a range of savings that were 0.5 times to 4 times the savings presented in Table 6. The high end of the range primarily reflects the use of marginal instead of average measures.[12]

D. Other Benefits (Not Quantified)

In addition to the benefits quantified above, the FAS design is expected to have many benefits that we were not able to quantify related to efficiency and reliability. It is our understanding that ERCOT initially proposed the FAS changes to create different services for the distinct operational requirements that are bundled into a single RRS service in CAS. This product separation is consistent with standard practice for good market design. Additionally, we understand that ERCOT hopes to increase system reliability through improving "the toolset to stabilize and maintain system frequency by providing more efficient ways to procure and deploy Ancillary Services."[13]

FAS provides extra flexibility for ERCOT to adjust system requirements as the resource mix changes and new technologies enter the market. For example, FAS may enable future load resources and other technologies to provide PFR without having to serve longer-duration CR duty, thus further reducing generation commitment and dispatch costs. Additionally, as the NERC-defined frequency response obligation (FRO) decreases over time due to higher

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[12] Lower estimate of savings result from determining the marginal unit based on the 2014 settlement quantity rather than settlement price. We believe this determination of the marginal unit does not accurately reflect the market conditions but report them here as a lower bound to our savings estimate.

[13] "667NPRR-01 Ancillary Service redesign 111814," ERCOT. November 8, 2014. Accessed Online. http://www.ercot.com/content/mktrules/issues/nprr/651-675/667/keydocs/667NPRR-01_Ancillary_Service_Redesign_111814.doc

participation of FFR resources, the Minimum PFR requirement is likely to decrease. FAS is able to capture the benefits of this reduction more than CAS. Under CAS, the system will adjust to reduced PFR requirements but will not move as dynamically as FAS since load participation is not explicitly accounted for. Section V discusses the effect of reducing the Minimum PFR requirement from 1,240 MW to 1,143 MW based on NERC's 2015 and 2016 requirements.

FAS will also enhance system reliability. Since FFR1 supports frequency at 59.8 Hz instead of at 59.7 Hz, and most events lead to frequency excursions of less than 0.3 Hz, FFR2 will be activated very rarely. Thus, FFR2 has a higher probability of being available for (the next) worst events. After a deployment, FFR1 is required the reset within 15 minutes so it will be available to be called to respond to any further system needs. Additional FFR2 resources may be attracted to the market due to their lower risk of being deployed.

Furthermore, FAS builds the equivalency ratio into the market clearing engine. As a result, the system will clear a sufficient amount of PFR in every hour based on exactly how much FFR is awarded. Every hour can therefore fully meet the total requirement for frequency response. This improves reliability over CAS because CAS does not recognize the equivalency ratio and can procure inadequate reserves. This shortage occurs when the equivalency ratio is higher than 1-to-1 and load participation is lower than anticipated during requirement development. The responsive reserve buffer described in Section IV would ensure reliability in most of these hours, but not all.

FAS is further expected to improve reliability through stricter regulations on qualifying PFR providers. In CAS, generators are allowed to provide 20% of their capacity. Historically, some resources have not delivered their full RRS obligation when called, while other resources have provided more than their obligation. This behavior means operators cannot know whether sufficient amount of Gen-RRS will be available to respond to an event. In contrast, FAS will include performance feedback based on resources' demonstrated response during historic events, rewarding the more responsive resources and limiting the less responsive ones. We understand from ERCOT that many resources have not been able to perform at 20%, and other resources are likely to be able to provide more than 20%.

Furthermore, once this process is implemented, it is likely that the PFR cleared in the market will be more distributed among resources (if many resources are limited to less than 20%), which will lead to faster and more reliable frequency response. All of these factors may lead to lower PFR requirements in the future.

Under the FAS proposal, any one unit is limited to providing a maximum of 25% of the system-wide regulation requirement. This rule will lead to a more distributed and reliable response from regulation reserves than under CAS. While the other benefits discussed in this section are integrally tied to the FAS design, these last two reliability benefits could be achieved through modifications of CAS design.

V. Benefits Under Alternative Assumptions

A. Non-Spinning Reserve Service Reduction Under CAS

ERCOT's Board of Directors recently approved an amendment to the current ancillary service design that will reduce non-spinning reserve requirements for 2016 and beyond.[14] It reduces the average Non-Spinning Reserve procurement from 1,931 MW to 1,464 MW in 2016; in 2024, requirements will decrease from 2,000 MW to 1,464 MW on average, with the biggest reductions occurring at night. In the recently approved method, ERCOT sets overnight hour requirements to meet the 70–80th percentile of net load forecast errors, whereas the current method meets the 95th percentile. We understand from ERCOT staff that the new method should not compromise reliability at night, when plentiful commitment headroom can help meet load forecast errors.

Reducing the requirements under CAS lowers the incremental savings from FAS. However, FAS reduces Contingency Reserve requirements below CAS's revised Non-Spinning Reserve requirements by setting requirements based on different methodology that is tuned to hourly system conditions, as discussed in Section III. Even under the recently approved CAS changes, Non-Spinning Reserve will be procured to meet net load requirements and set as one daily shape in 6 four-hour blocks applied to every day of the month (only 6 potential values). Figure 8 compares the current and recently approved CAS Non-Spinning Reserve requirements with the FAS Contingency Reserve requirements in 2016. As shown, the annual average quantities are 1,931, 1,464, and 1,175 MW under current CAS, recently approved CAS, and FAS, respectively. FAS reduces requirements by 756 MW on average relative to the current CAS, but it would reduce requirements by only 289 MW on average relative to the recently approved CAS.

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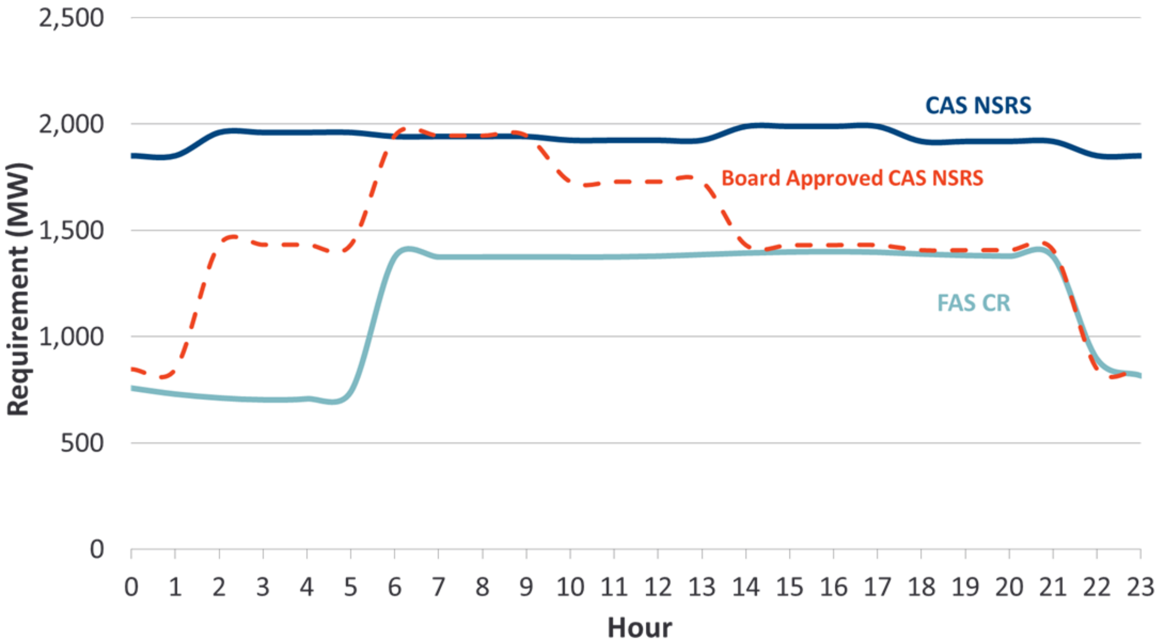
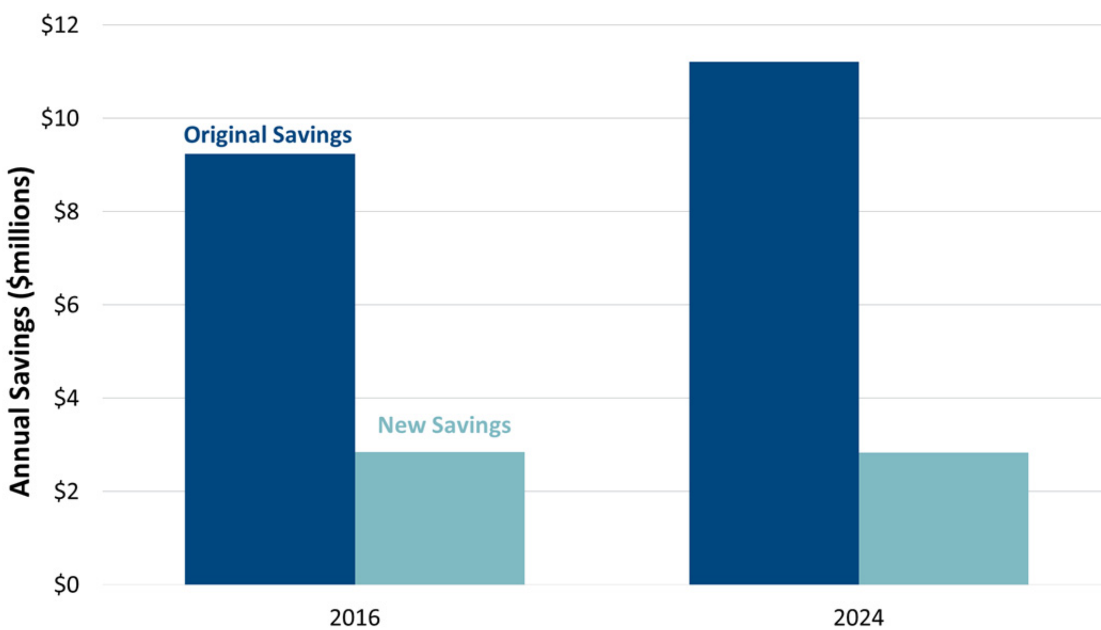
14 "Item 9: 2016 Methodology for Determining Minimum Ancillary Service Requirements," ERCOT Board of Directors. December 8, 2015. Accessed Online. http://www.ercot.com/content/wcm/key_documents_lists/76324/9_2016_Methodology_for_Determining_Minimum_Ancillary_Service_Requirements.pdf

Figure 8: Comparison of Board Approved 2016 NSRS with FAS CR Requirements



FAS's savings would be reduced if compared to the recently approved CAS with lower NSRS requirements. As shown in Section V, NSRS/CR requirements affect real-time opportunity costs without significantly affecting day-ahead production costs. Therefore, NSRS/CR savings come solely from reduced real-time opportunity costs. Instead of the original $9.2 million real-time opportunity cost savings in 2016, the new savings would be $3 million. Figure 9 below compares the reduction in savings for both 2016 and 2024.

Figure 9: Reduction in NSRS Real-Time Optionality Savings with Board Approved Requirements



B. Lowered Minimum PFR Amount

In mid-September 2015, NERC published its annual "Frequency Response Annual Analysis" report.[15] This analysis is used to determine the Interconnection Frequency Response Obligations (IFRO) in each NERC region, including ERCOT. ERCOT has an IFRO of 381 MW/0.1Hz for 2016, which translates to a Minimum PFR requirement of 1,143 MW. This minimum is 97 MW lower than the 2015 minimum that we used in the model (1,240 MW).

The Minimum PFR decrease has a greater effect in FAS than CAS. FAS explicitly recognizes the equivalency ratio of FFR and PFR and allows more than 50% of responsive reserves to come from FFR. When the Minimum PFR is reduced, more FFR can displace PFR and reduce the amount of potentially costly reserves coming from generation resources. Under CAS, however, the 50% cap on Load Resource participation will limit such substitution. The effects on PFR needs are presented below in Table 7.

Table 7: Average CAS and FAS Requirements with Lower Minimum PFR

	2016			2024		
	CAS	FAS	(FAS - CAS)	CAS	FAS	(FAS - CAS)
RRS	2,789	-	-	2,757	-	-
PFR+FFR (In PFR Terms)	-	3,245	-	-	3,165	-
Expected FFR	1,333	1,441	107	1,318	1,418	100
Expected PFR	1,456	1,236	(220)	1,439	1,232	(207)

Since reducing the Minimum PFR has a greater effect on FAS requirements than CAS requirements, it also increases the benefits of FAS more than shown in Section IV. To approximate the increase in savings, we scaled our original analyses based on the reduced amount of expected PFR procurement. The results are summarized in Table 8 below. (Note that scaling does not account for possible non-linear changes in unit commitment, but it provides a useful indicator of value.)[16]

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15 "2015 Frequency Response Annual Analysis," NERC, September 16, 2015.

16 We did not rerun the PLEXOS model to re-calculate production cost savings under the new PFR requirements. Instead, we increased the production cost savings between CAS and FAS based on the approximate per MW value of PFR reductions calculated using the original PLEXOS runs. Since PFR

Continued on next page

Table 8: Effect of Minimum PFR change on Overall Savings

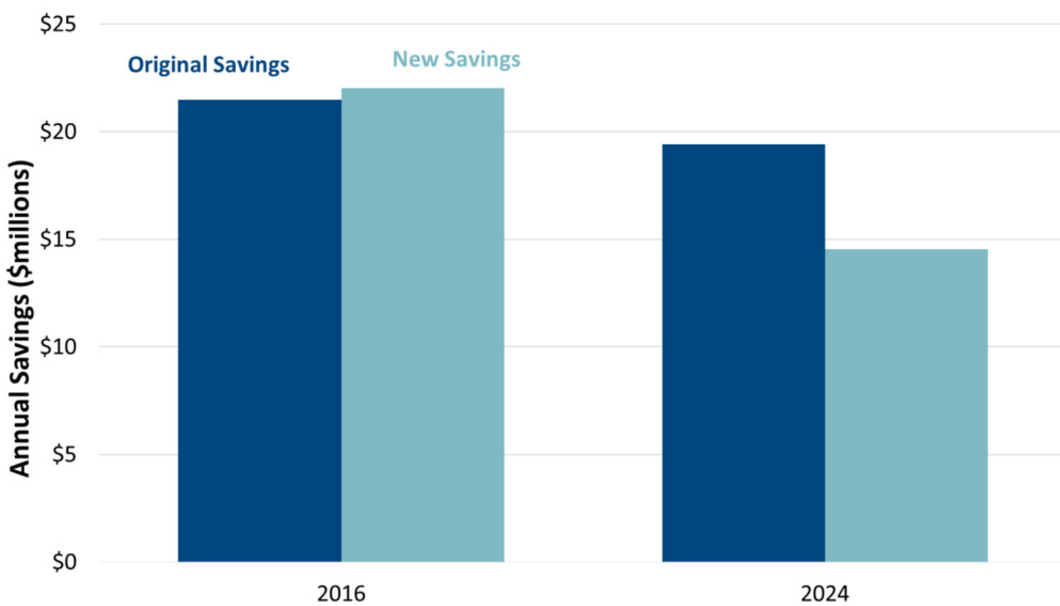
Case	Metric	Original Assumptions			New Min PFR Assumptions			Change
		CAS	FAS	Savings	CAS	FAS	Savings	
2016	Day-Ahead Production Cost Savings	-	-	$9.1	-	-	$14.3	**$5.2**
	Real-Time Opportunity Costs	$32.3	$29.2	$3.2	$32.0	$27.1	$4.9	**$1.7**
2024	Day-Ahead Production Cost Savings	-	-	$3.4	-	-	$4.8	**$1.4**
	Real-Time Opportunity Costs	$37.4	$32.6	$4.8	$37.0	$30.1	$6.9	**$2.0**

Note: All dollar values reported above are nominal. The 2024 case includes savings with new tech.

C. Non-Spinning Reserve and PFR Min Change

As shown above, the Non-Spinning Reserve (NSRS) change lowers the savings expected from FAS implementation, and the reduced Minimum PFR amount increases the expected savings. When we perform our savings analysis with both changes in place the total savings are similar to our modeled Current Trends cases.

Figure 10: Overall Change in Benefits



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requirements affect commitment and dispatch in the model, which only additional PLEXOS runs could capture, the additional production cost reductions we calculated due to the Minimum PFR change is a rough approximation of potential additional savings.

VI. Other Considerations

A. Implementation Costs

ERCOT estimates one-time implementation costs for FAS between $12 and $15 million.[17] These costs are based on 2014 vendor estimates. There may be additional costs for individual market participants. We have not heard from any participants on how much they expect to pay or what these costs represent, so we did not include any additional implementation costs in our analysis.

B. Alternative Procurement Options

ERCOT proposes to define its FAS requirements on a day-ahead basis when it has a good forecast of net load, inertia, and thus the needs for responsive reserves and supplemental reserve. This approach would better tune procurement to the needs of the system than current practices, where needs are determined as much as a year in advance.

Our analysis assumes this dynamic approach for both CAS and FAS, since we define reserve requirements based on simulated commitments in PLEXOS that account for system conditions that would be available on a day-ahead basis. Assuming the day-ahead determinations for both CAS and FAS allowed us to focus on the fundamental differences in requirements as opposed to procurement practices. However, this understates the benefits of FAS relative to current CAS practices. CAS would be substantially less efficient than we modeled if needs were still determined on a year-ahead basis, when system conditions are not known and requirements have to be set conservatively high. ERCOT staff demonstrated this point to us by analyzing reserve requirements for 2015 as determined in October 2014 versus what they would have procured in a day-ahead process: on average the day-ahead procurement reduced RRS requirements by 343 MW through October 21, 2015.

Alternatively, CAS could be modified to determine requirements on a day-ahead basis. However, this would be costly to implement; and the incremental implementation cost of FAS would then be lower than the $12 to $15 million ERCOT has estimated.

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17 "ERCOT Impact Analysis Report for NPRR667," ERCOT. November 18, 2014. Accessed Online. http://www.ercot.com/content/mktrules/issues/nprr/651-675/667/keydocs/667NPRR-02_Impact_Analysis_111814.doc

Some market participants have raised concerns about their ability to predict FAS's dynamic ancillary services requirements and to procure and hedge accordingly. They have proposed alternative procurement methodologies, including continuing to set procurement in the prior October or determining requirements at the beginning of each month. We do not believe ERCOT should adopt those alternative proposals because they would be economically inefficient, and they are not necessary. They would be economically inefficient because ERCOT has much less information on system conditions year-ahead or month-ahead than it has day-ahead, including weather-driven load conditions, wind and sun forecasts, and unit outages. Thus they would have to include a sizable buffer to be prepared at all times for the lowest inertia conditions (within a given time period) that may occur only rarely. They would procure more reserves than needed. It would be comparable to fixing the hourly load forecast at a level above expected loads, then enforcing that load level physically by loading up banks of resistance heaters.

Dynamic requirements (which could be adopted under either FAS or an enhanced CAS) will indeed create uncertainty about the quantities of ancillary services that will be required. However, we expect that market participants will figure out how to optimize their behavior under these conditions, just as they did when other market design efficiencies, such as locational marginal pricing, were introduced.

Thus we did not evaluate alternative, less dynamic procurement options. However, we do note that our benefit-cost analysis assumed that even CAS incorporates dynamic requirements. If we had not, our cost benefit estimates would have been higher.

C. Alternative PFR/FFR Price Formation Options

ERCOT and stakeholders have had discussions on the optimal pricing strategy for FFR under FAS design. The three possible scenarios are:

- *Price FFR the same as PFR*, similar to CAS paying Load-RRS resources the same price as Gen-RRS. However, that would imply a 1-to-1 equivalency ratio, which is consistent with CAS's market clearing engine but not FAS's. FAS recognizes the relative effectiveness of FFR and PFR in supporting frequency as inertia varies. When inertia is low, FAS counts FFR at a higher equivalency ratio toward meeting total responsive reserve requirements.

- *Price FFR based at the PFR clearing price times the hourly equivalency ratio*. In this scenario, 1 MW of FFR would receive a higher price than 1 MW of PFR whenever inertia is low and the equivalency ratio exceeds one.
- *Price FFR jointly with PFR recognizing the equivalency ratio as well as the Minimum PFR/Maximum FFR constraint in each hour*. Whenever that constraint binds, FFR would price-separate below the PFR price times the equivalency ratio. Stakeholders have noted that this scenario would confront Load Resources with the prospect of low prices and would challenge them to adjust their offering strategies to ensure that they do clear at a price below their reservation price. Most Load Resources have traditionally offered at $0/MW.

We modeled scenario 2 in the PLEXOS model. Whether ERCOT chooses to implement the pricing mechanism in scenario 3 is independent of the other components of the FAS redesign. Additionally, we did not have any data on how scenario 3 would change offer behavior or participation of FFR resources. Directionally, FFR participation could back off slightly to avoid depressed prices; but participation could also increase as a result of FAS's inclusion of the equivalency ratio in FFR pricing, a factor we do not account for when assuming the same participation rates between FAS and CAS.

D. Evaluation of Benefits Possible In CAS

We evaluated the benefits of FAS compared to the current design of CAS (with one major modification assumed: day-ahead determination of requirements, tuned to system inertia and load resource availability). Our analysis implicitly assumes all of the elements of FAS could not be achieved within the current framework. However, ERCOT could in fact achieve some of the FAS benefits by making changes to CAS.

Section V.A discussed the proposed reduction in Non-Spinning Reserve procurements under CAS, which would make CAS more efficient. Nevertheless, the improved CAS design would still procure more Non-Spinning Reserve than the expected Contingency Reserve and Supplemental Reserve requirements in FAS.

Under a revised CAS, ERCOT could implement a performance-based approach for Gen-RRS instead of allowing all units to provide 20% of HSL. This change would improve reliability under CAS; however, since we did not capture any economic benefits of this change in our study the FAS economic benefits we presented would not be reduced if this change were made in CAS.

Furthermore, ERCOT could implement rule changes to Regulation provisions to include a limit of 25% from a single resource. However, in our study we did not see this rule binding in the FAS Regulation provisions. We would not expect that the Regulation rule change in CAS would affect Regulation provisions or the benefits presented to FAS.

The reduction of PFR needs compared to Gen-RRS, caused by elimination of the 50% Maximum on Load Resource participation and the buffer, is fundamentally tied to FAS design. For reliability reasons, the 50% limit on Load Resource participation should probably be maintained unless the equivalency ratio between PFR and FFR is explicitly accounted for in the market mechanism—but then CAS would essentially become FAS.

E. Relationship to Other Potential Market Design Changes

ERCOT is considering implementing real-time co-optimization of reserves with the energy market.[18] Currently reserves are co-optimized with energy in the day-ahead market, and then held at those levels in the real-time market. Units are only re-dispatched for energy purposes. If the market implements real-time co-optimization, we expect that will achieve numerous efficiencies and reduce the real-time opportunity cost of providing reserves. The incremental savings from FAS's reduced procurement of reserves would therefore decrease.

However, we do not expect real-time co-optimization to remove all of the incremental RT opportunity cost savings; for example, consider a unit that clears in the day-ahead market providing regulation down with a marginal cost of $50/MWh. Without co-optimization, if the real-time price of electricity drops to $48/MWh, the unit cannot lower its output and buy in real time because it is committed to providing regulation down. It foregoes $2 in optionality cost per MW. However, real-time co-optimization allows this unit to shed its Regulation Down commitment if the new marginal units in the RT market can provide the entire Regulation Down requirement. However, if the co-optimization cannot find new Regulation Down providers, the day-ahead marginal unit will still need to provide Regulation Down and will incur a RT opportunity cost of $2/MW. For this reason, RT co-optimization has the potential to avoid RT opportunity costs but will likely not completely remove them.

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[18] *ERCOT's Impact Assessment of Real-Time Energy & Ancillary Services Co-optimization*. Prepared for the PUC of Texas. Accessed at http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/Impact_Assessment_Real-Time_Energy_and_Ancillary_Services.pdf

VII. Conclusions: Cost-Benefit Summary

We found that FAS design would save $21.5 million in 2016 and between $15.7 and $19.4 million in 2024 under Current Trends, depending on the entry of new technologies. These savings are driven by reductions in RRS/PFR and NSRS/CR requirements between CAS and FAS designs. The PFR requirement reduction saves both day-ahead production costs and real-time opportunity costs, while NSRS/CR reduction saves only real-time opportunity costs.

We also analyzed two alternative assumptions about CAS and FAS designs, one decreasing the incremental benefits of FAS and the other increasing them. The alternative with lower benefits corresponds to revised Non-Spinning Reserve requirements recently approved by the ERCOT Board of Directors for the CAS design. This change will decrease the amount of Non-Spinning Reserve required, especially in overnight hours. When we implemented this change in CAS, the FAS savings were reduced to $15.1 million in 2016 and $11 million in 2024. In contrast, we analyzed the newly announced 1,143 MW Minimum PFR announced by NERC (the previous minimum was 1,240 MW), which increased the FAS benefits. With the new Minimum PFR in place, we estimated FAS savings of $28.4 million in 2016 and $22.8 million in 2024. With both the new Non-Spinning Reserve design and new Minimum PFR implemented, we estimated the total savings of FAS would be $22 million in 2016 and $14.4 million in 2024. These savings are similar to our original estimates.

Each case for which we estimated benefits represents a single year of potential savings. These estimated savings would lead to substantially greater value (over several years) than ERCOT's one-time implementation costs of $12 to $15 million.

These estimates are uncertain due to potential changes in market conditions over time. Points of uncertainty include net load, fuel prices, environmental requirements, and retirements. As one indicator, the changes in net load and other factors between our 2016 and 2024 cases cause estimated benefits to change from $21.5 million to $15.7 million (before considering the effects new technologies).

In addition to the market uncertainties, our modeling methodology includes inherent uncertainties. For example, the savings depend on how the combined-cycle fleet is modeled in PLEXOS. We modeled combined cycles as single plants (with duct burners separated) in our analysis; we could have modeled them as individual units able to operate in various configurations. Additionally, the changes between FAS and CAS cases are small compared to unit commitment optimization tolerance and the size of units being committed. Finally, varying our approach to real-time opportunity cost savings affects benefits by 0.5 to 4 times, as discussed in Section IV.C.3.

However, we are confident that the rough magnitude of quantified benefits is robust. We found benefits that are consistent with our high-level estimates: reduction of PFR quantities × historical RRS price + reduction in NSRS quantities × historical NSRS price. A reduction in ancillary service quantities will save money as long as ancillaries are costly to provide.

Moreover, there are numerous additional benefits we did not quantify. FAS will increase reliability by recognizing the equivalency ratio and always procuring enough frequency responsive reserves even when FFR quantities are unexpectedly low. FFR1 will support frequency at 59.8 HZ, meaning FFR2 will be activated less frequently and will more likely be available for secondary events, and this will lower the cost of providing FFR2, which may encourage participation. FAS will also increase the system's flexibility to enable new resources and adjust to reduced Minimum PFR requirements overtime.

In summary, we regard FAS to be good market design: it unbundles AS needs into distinct products that can be served by a wider set of suppliers than the current products, and it tunes procurements and product substitution rates to system conditions.

Appendix

I. PLEXOS Model Bases Cases

Section III introduced the PLEXOS production cost model and the cases run in the model. This appendix documents the assumptions used in each of these cases.

A. PLEXOS Model Structure

PLEXOS is a modern production cost model developed and licensed by Energy Exemplar. PLEXOS uses full mixed integer programming techniques to optimize unit commitment, and it co-optimizes the commitment of ancillary service products with the provision of energy. Furthermore, it has flexibility in modeling different ancillary service products with various definitions. The model's flexibility in ancillary service modeling was essential for capturing the changes between the current and future ancillary service designs.

B. Base Case Inputs

We adopted the supply and demand assumptions directly from LTSA scenarios that ERCOT and stakeholders selected for us to analyze, with a few modifications. We modified the generator unit list to be consistent with current expectations of build-outs and reliability. We modified the base year weather conditions used for the hourly load shape and hydro conditions to 2010 to match the wind and solar shapes because time-synchronization of these resources is important for determining and understanding realistic ancillary service needs. We standardized unit operating data by unit type to enable better understanding of results. We also modified the transmission zones, LTSA modeled 4 zones in ERCOT, and the CBA used one zone. We did not modify the LTSA scenarios' fuel prices.

1. Generators and Load

a. Installed Generators

As explained in Section III, the cases we analyzed are based on ERCOT's LTSA scenarios, modified to account for planned generator additions and generic additions to reflect economic entry. The "Current Trends" scenario required additional gas-fired generation in order to meet a reserve margin consistent with the "economic equilibrium" reserve margin determined from The

Brattle Group's Economically Optimal Reserve Margin (EORM) study.[19] We estimated the reserve margin assuming the following:

- Numerator includes all generation's summer capacities, with renewables rated consistent with the CDR, plus 50% of DC ties.
- Denominator includes the peak hour load in the model, assuming the load forecast in the model is supposed to represent normal 50/50 weather.

In the EORM study, we found the economic equilibrium reserve margin to be roughly 11.5% under the current Operating Reserve Demand Curve pricing and using the May 2013 CDR accounting of wind capacity value (this equates to about 13.5% under current CDR accounting). In order to match this reserve margin in the Current Trends scenario, we added an additional 2,200 MW of gas-fired generation (while assuming Load Resources, Emergency Response Service, and TDSP programs remain constant).

The load forecasts for peak and energy are very close to 2014 LTSA. The 2014 LTSA used 50/50 forecast based on the past 11 weather years (2002-2013, excluding 2008). 2010 has historical load peak and energy close to the average of the 11 weather years considered in the 2014 LTSA. The load forecast based on 2010 weather condition was used in this study in order to have time series for load, wind, solar, and hydro availability, all of which depend strongly on weather variables, to be based on the same underlying historical weather pattern. Table A-1 summarizes the installed capacity by unit type for each of the base cases.

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19 Newell *et al.*, "Estimating the Economically Optimal Reserve Margin in ERCOT." Prepared for The Public Utility Commission of Texas, January 31, 2014.

Table A-1: Load and Supply Resources

Assumptions (MW unless otherwise noted)	2016 Base Case	2024 Current Trends	2024 Stringent Environmental
Load			
Avg. Energy Growth (%)	1.90%	1.60%	1.40%
Peak Load	74,700	82,220	81,230
Supply Resources			
Nuclear	5,164	5,164	5,164
Coal	17,967	17,117	16,037
Combined Cycles	34,613	41,413	40,063
CT & IC	11,451	14,221	11,839
Gas Steam	12,457	7,565	7,565
Seasonal Coal Mothball	1,875	1,875	1,875
Wind Capacity	17,551	21,528	28,204
Solar Capacity	246	3,546	9,246
All Other Capacity	1,547	1,547	1,867
Total Nameplate Capacity	**102,871**	**113,976**	**121,860**

Note: CT & IC stands for Combustion Turbine & Internal Combustion Engine

The full capacity and load of Private Use Network (PUN) facilities are included in the table above and in our simulations. In the simulations, we set the production of these generators at their 2014 levels rather than committing and dispatching them by PLEXOS since we would not have been able to model the host's steam needs that affect operations. Because we included the full amount of PUN generation (rather than net generation), we also included the PUN load in the model. This treatment of PUNS is consistent with other ERCOT planning models, and captures their inertia contribution to the total system inertia more realistically.

b. Standard Assumptions by Unit Type

Generating unit operating characteristics were standardized across unit types to capture the average operation of the fleet, as summarized in Table A-2.

Table A-2: Generic Unit Characteristics

Generator Type	Ramp Rate	Minimum Up Time	Minimum Down Time	Variable O&M	Full Load Average Heat Rate
	MW/min	Hrs	Hrs	$/MWh	Btu/kWh
Nuclear	3	-	-	$2.5	10,168
Coal	4	24	12	$6.0	10,400
Combined Cycles	10	8	4	$2.5	7,580
CT & IC	4	1	1	$7.5	12,575
Gas Steam	6	8	8	$1.8	11,300

*CCs modeled as single trains, with duct burners modeled separately (with operations tied to parent CC) and not able to provide AS

**Quick start units are given a non-standardized ramp rate based on past performance

Individual unit full load heat rates (FLHR) were kept in the model, but unit type heat rate curves were standardized:

- GT: 4 blocks, 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR
- CC: 4 blocks, 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR
- Coal: 4 blocks, 30% capacity at 110% of FLHR, 50% capacity at 93% of FLHR, 75% capacity at 95% of FLHR, 100% capacity at 100% of FLHR
- Steam oil/gas: 4 blocks, 20% capacity at 110% of FLHR, 50% capacity at 95% of FLHR , 75% capacity at 98% of FLHR, 100% capacity at 100% of FLHR

Though unit ramp rates were standardized, a unit's ability to provide some reserves is also dependent on Minimum and Maximum operating levels of the plant. For example, a 100 MW plant with a ramp rate of 10 MW per minute and a minimum stable level of 50% would be limited in regulation amount by operating limits and ramp rate. Larger units are more likely to be limited by ramping capability. Table A-3 summarizes the average reserve capability by unit type.

Table A-3: Average Reserve Capability by Unit Type

Generator Type	Offline Non-Spin Capability	Regulation Down Capability	Regulation Up Capability	Responsive Reserve Capability
	%	%	%	%
Nuclear	-	-	-	-
Coal	-	3%	3%	17%
Combined Cycles	2%	10%	10%	14%
CT & IC	28%	13%	13%	7%
Gas Steam	1%	11%	11%	19%

Note: Online non-spin capabilities not shown here because capabilities vary with each unit's hourly output vs. HSL (and ramp rates).

We allowed units to provide reserve types based on their 2014 qualifications (*e.g.*, if a thermal unit was qualified for RRS and NSRS in 2014, it was qualified to provide RRS and NSRS in the CAS cases and PFR and CR in the 2024 cases). Specific Qualifications and mapping for reserves are provided below in Table A-4.

Table A-4: Resource Qualifications and Mapping between CAS and FAS

Resource Qualifications in CAS	Mapping of Resources in FAS Modeling
Thermal units qualified for **Gen-RRS** can provide **RRS** limited by the lower of the following: • 20% of installed capacity • 10-minute ramping capability Hydro units can provide **Gen-RRS** to max offered in 2014	Qualified units can provide: • **PFR**, up to 20% of installed capacity • **Contingency Reserve**, limited by their 10-minute ramp
Load resource qualified for **Load-RRS** can provide **RRS** limited by 2014 participation	Qualified Load-RRS resources can provide: • **FFR2** • **Contingency Reserve 2** • **Supplemental Reserve 2**
Thermal units qualified for **Non-Spin** are limited by: • Online: 30-minute ramping capability • Offline: 2014 participation	Qualified units can provide **Contingency** and **Supplemental Reserves** limited by: • **Contingency:** Quick Start Generation Resources can provide Contingency Reserve from online or offline status • **Supplemental:** o Online: 30-minute ramping capability o Offline: 2014 participation
Units qualified for **Regulation Up** and/or **Regulation Down** are limited by:	Qualified units can provide **Regulation Up** and/or **Regulation Down** limited by:

Resource Qualifications in CAS	Mapping of Resources in FAS Modeling
• 5-minute ramp capability	• 5-minute ramp capability
New generation resources added assumed to qualify to provide CAS resources similarly to the existing resources of the same type/size/ramping capability	New generation resources added assumed to qualify to provide FAS resources similarly to the existing resources of the same type/size/ramping capability

In our study, the sum of all committed units' inertia based on MVA rating and inertia constant (H) determined the system inertia, which in turn determined the frequency response requirements. ERCOT staff obtained individual unit inertia constants from operations and used these individual values in the model. Table A-5 summarizes the average MVA ratings and H constants by unit type that ERCOT staff calculated for the purpose of this study.

Table A-5: Average Inertia Characteristics

Generator Type	Average MW	Average MVA	Average H
Nuclear	1,291	1,450	4.09
Coal	633	785	2.62
Combined Cycles	475	600	4.97
CT & IC	87	100	5.17
Gas Steam	240	300	2.90
Hydro	20	30	2.49

c. *Renewable Generation Profiles*

We chose to model hourly wind and solar generation based on 2010 historical weather patterns, consistent with our hourly load data. ERCOT provided the wind and solar generation profiles. The wind profiles reflect wind speed data provided by AWS True Power for all existing wind generators and from 130 hypothetical future wind generation units. The full solar profiles reflect data gathered for 254 Texas counties for four different types of solar technologies, single-axis tracking, fixed tilt, solar thermal, and residential. This study, in line with the LTSA, uses only the single-axis tracking and residential profiles.

d. Hydroelectric Resources

Hydroelectric units are modeled as energy constrained resources. ERCOT developed the monthly energy constraints for hydro units using historical hydro generation from 2010, to be consistent with our load, wind, and solar profiles. On the top of monthly energy constraints, hydro is treated as the last resource by applying a high variable O&M charge. Based on multiple model runs, ERCOT staff found that $58/MWh variable O&M charge makes the total annual generation from hydro units similar to historical hydro generation in 2013 and 2014, so hydro units are modeled with a $58/MWh variable O&M charge.

e. Transmission Modeling and DC Ties

The ERCOT footprint is modeled as a single bubble with no transmission limitations between different areas. This representation of the ERCOT system is consistent with how ancillary services products are cleared in the ERCOT market. The existing DC ties are modeled with fixed schedules based on the historical 2010 hourly flows.

f. Load Resources

Load resources are modeled as a single unit in the model. These resources are not allowed to provide energy. We determined the offer prices of load resources by examining the historical offer curve for load resources in 2014. In 2014, over 94% of the resources offered at $0, roughly 1,130 MW on average for a given hour. Smaller amounts of load resources offered at values above $0, approximately 55 MW offered at $3, and occasionally 5-10 MW offered at more than $200. Since the majority of load resources offered at $0, and we do not know why other providers offered above $0, we chose to simplify the modeling by all resources offering at $0.

The participation of load resources varies by month-hour, consistent with 2014 historical patterns in ERCOT. As of December 2014 there were 3,063 MW of qualified load resources in ERCOT. Before June 1 2015, 1,400 MW of load resources were allowed to clear in a given hour, and historic data has shown 1,600 MW offering into the market. When 1,150 MW (before April 2012) were allowed to clear in the market, often 1,400 MW offered into the market. The 2014 participation pattern of load resources is shown in the participation duration plot in Figure A-1, while the average participation over the last four years is summarized in Table A-6. We concluded from our analysis of these historic patterns that when the cap on Load Resources is increased, load resource participation increases commensurately. Participation rates as percentage of the cap will remain roughly constant.

As noted above, we increase the quantity of load resources available in PLEXOS based on the maximum allowed load resource reserves, keeping participation levels constant. This assumption is a simplification for modeling purposes. We could have assumed that Load Resource participation remained constant in MW terms and that the small increase in FFR opportunity would be filled by new technology. If we had filled this opportunity with new technology the FAS benefits would have been similar to the benefits that we presented.

Figure A-1: 2014 Load Offers and Awards

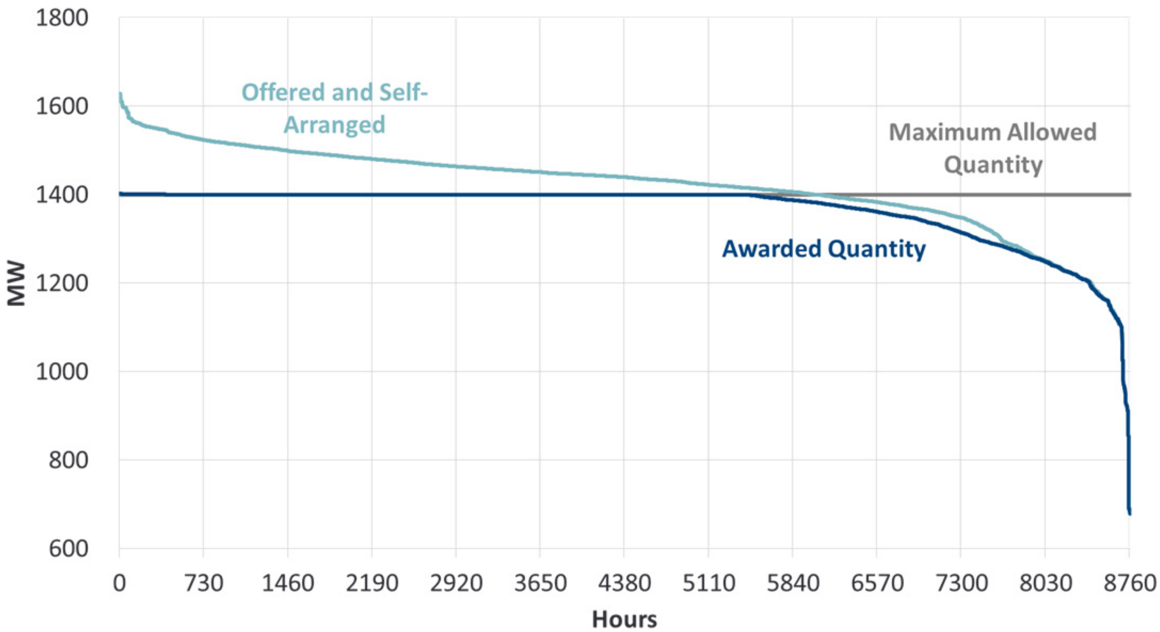


Table A-6: Historical Load Resource Participation (as a % of Load Resource Cap)

	2011	2012	2013	2014
Max	100%	100%	100%	100%
Min	42%	42%	60%	48%
Avg	96%	90%	94%	96%
Median	100%	94%	97%	100%

2. Fuel Forecasts

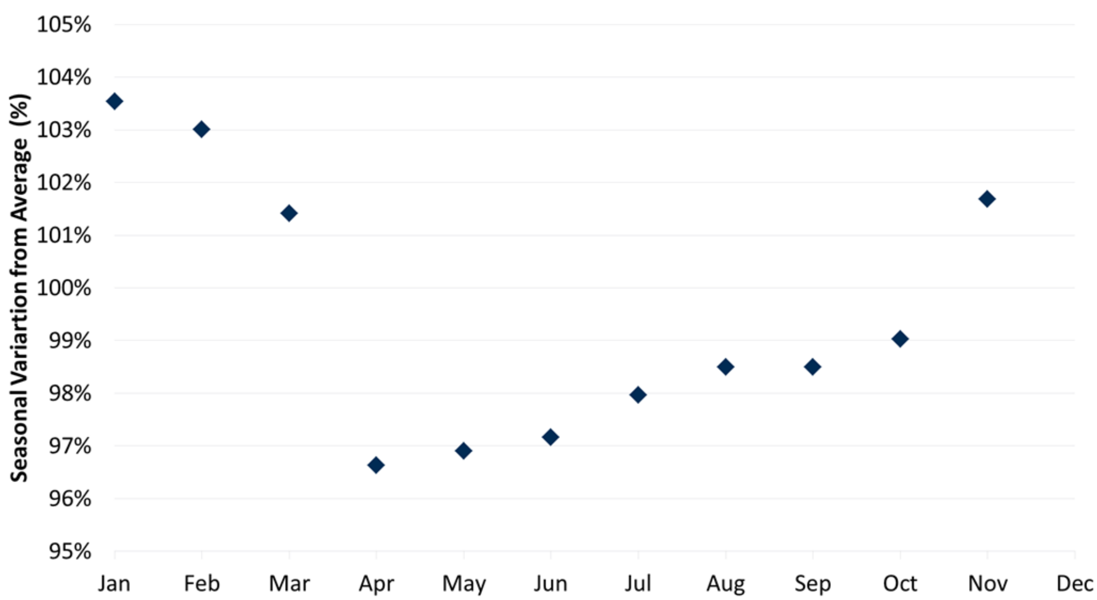
The fuel prices in the model are based on fuel prices from the EIA 2014 early release, which were used in the ERCOT 2014 LTSA. Annual natural gas prices were developed for the ERCOT 2014 LTSA by averaging EIA and Wood Mackenzie prices. Given the likely increase in demand for natural gas under stringent environmental conditions, the natural gas prices in the 2024 SE case are $1.50 higher than the 2024 CT price. Coal prices were an average of the 2012 and 2014 EIA AEO and information from SNL for PRB and Lignite.

Table A-7: Fuel Prices ($/MMBtu)

Fuel Type	2016 CT	2024 CT	2024 SE
Natural Gas	$4.35	$5.93	$7.43
Coal - Gulf Lig	$1.67	$1.92	$1.92
Coal - PRB	$0.88	$1.07	$1.07
Biomass	$2.10	$2.10	$2.10
Geothermal	$0.00	$0.00	$0.00
Uranium	$0.89	$0.89	$0.89
Other	$3.50	$3.50	$3.50

Monthly multipliers were applied to the annual natural gas prices to represent the historic seasonality of natural gas. As shown in Figure A-2, gas prices are cheapest in the spring and most expensive in the winter.

Figure A-2: Monthly Natural Gas Price Compared to Annual Average



Final plant level delivered coal prices were developed by adding transportation costs, developed during the 2013 DOE study, to the appropriate coal price.

Table A-8: Coal Transportation Rates ($/MMBtu)

Coal Unit	2016	2024
Limestone	$0.33	$0.40
Martin Lake	-$0.39	-$0.47
Monticello 3	-$0.26	-$0.32
PUN COAL	-$0.23	-$0.28
San Miguel	-$0.09	-$0.11
Sandow 5	-$0.23	-$0.28
Twin Oaks	$0.25	$0.30
Big Brown	$1.55	$1.87
Coal-TX	$1.45	$1.75
Coleto Creek	$1.57	$1.90
Fayette	$1.70	$2.06
Gibbons Creek	$1.48	$1.79
J K Spruce	$1.06	$1.28
J T Deely	$1.06	$1.28
Monticello 3	$1.57	$1.90
Oklaunion	$1.28	$1.54
Prototype Coal.FGB	$1.45	$1.75
W A Parish	$1.61	$1.94

C. Base Case Validation

We benchmarked the base case PLEXOS model to 2014 and 2013 operations to ensure that the model was performing in alignment with actual market operations. In the validation process we checked the unit commitment patterns by comparing headroom on an average hour-month basis. We also ensured that dispatch patterns were similar to historical level by comparing month-hour average implied market heat rates and annual average reserve contributions by unit type.

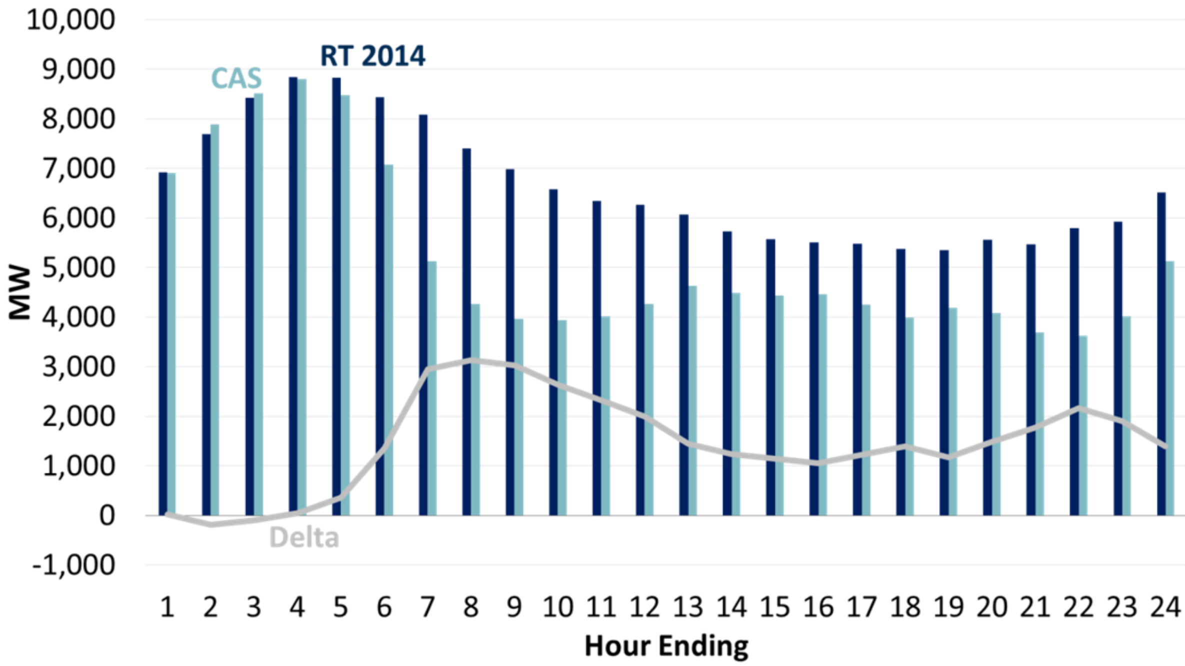
1. 2016 CT: benchmark to 2013/14

a. Headroom

"Headroom" represents the amount of online thermal capacity minus the thermal output. Figure A-3 below compares the simulated headroom in our 2016 CAS case to historic values from 2014. The simulation has lower headroom than the 2014 real-time because the PLEXOS model has perfect foresight and can commit units more efficiently than reality, due to real-world uncertainties. This finding is consistent with other production cost models. Note the 2013 headroom comparison is very similar to the 2014 figure, so we did not include it in the report.

Since our study relies on comparison of the CAS and FAS cases, we are not concerned by the tighter commitment of the model. The tighter commitment will affect both FAS and CAS requirements and results.

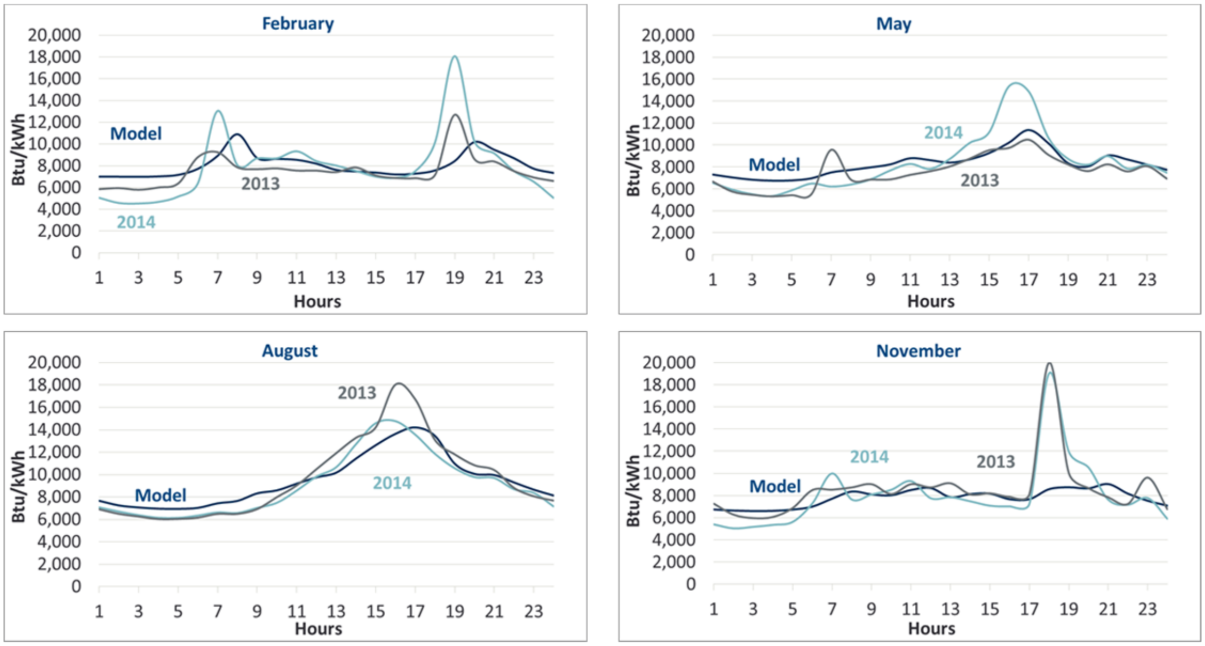
Figure A-3: Headroom Comparison Between 2014 Historical and 2016 Base Case



b. *Implied Market Heat Rates*

The PLEXOS model does not capture real-time scarcity prices, but the energy prices and implied market heat rates follow closely to the historical monthly patterns aside from scarcity hours. Figure A-4 below shows how the models implied market heat rate compares to historical heat rates for selected months.

Figure A-4: Implied Market Heat Rate Comparison 2016 CAS to Historical – Select Months



c. *Average Annual Reserve Contribution by Unit Type*

We verified that our 2016 CAS PLEXOS case had the right types of units providing ancillaries by comparing to 2014 data. As Table A-9 below shows, each unit type is providing within 6% of 2014 actuals.

Table A-9: Benchmark AS Procurement by Unit Type

	2014				2016 CAS Case				Difference (2016 CAS Case - 2014)			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)
Coal	5%	7%	26%	1%	6%	9%	25%	0%	1%	2%	-1%	-1%
CC	30%	77%	69%	13%	34%	70%	66%	15%	3%	-6%	-3%	2%
CT & IC	7%	7%	2%	83%	3%	13%	8%	82%	-4%	6%	6%	-2%
Gas Steam	3%	6%	3%	3%	2%	4%	1%	3%	-1%	-2%	-2%	0%
Hydro	7%	0%	0%	0%	9%	0%	0%	0%	2%	0%	0%	0%
Load Resources	48%	0%	0%	0%	48%	0%	0%	0%	0%	0%	0%	0%
Battery	0%	3%	0%	0%	0%	4%	0%	0%	0%	1%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**0%**	**0%**	**0%**	**0%**

2. 2024 CT: Compare Inputs and Outputs to 2016 CT

a. *Capacity Factor Comparison*

Capacity Factor changes between 2016 and 2024 cases were small but not insignificant. In 2024, coal units generate more due to increased load with fewer resources available due to ~1 GW of coal retirements. Furthermore, while CC units show significant increases in energy production, these are matched by increases in CC capacity, leading to relatively insignificant changes in capacity factor. The increased CC capacity leads to less utilization of CT, IC, and Gas Steam units. Table A-10 shows all the variation of capacity factors between the 2016 CAS and 2024 CAS cases.

Table A-10: Capacity Factor Comparison between 2016 CAS and 2024 CAS

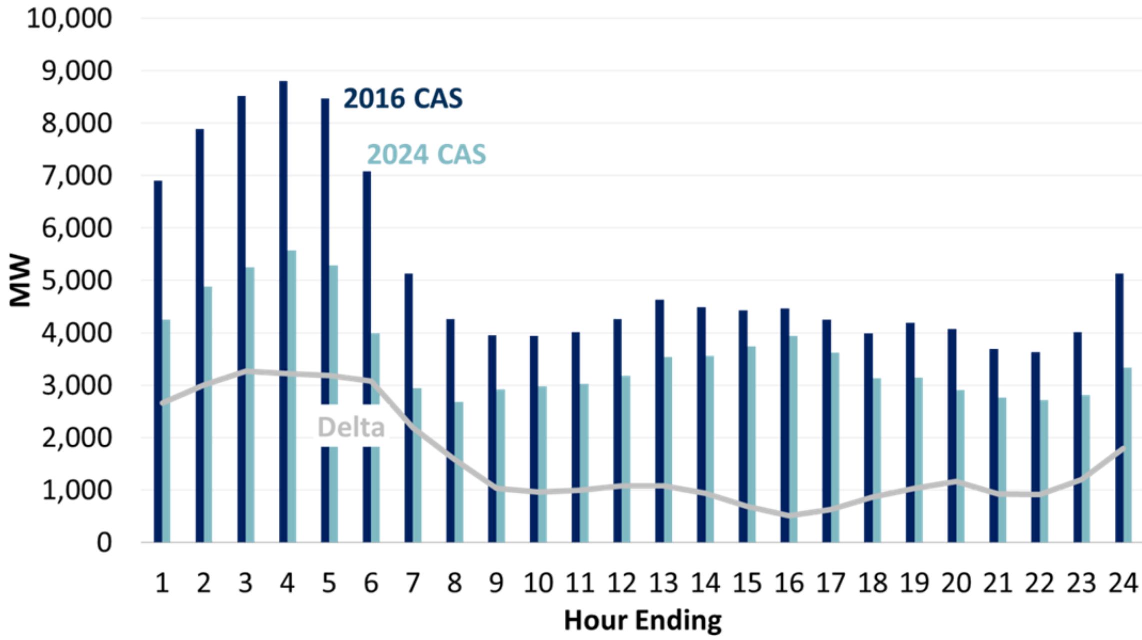
Type	2016 CAS Generation (GWh)	2024 CAS Generation (GWh)	2016 CAS Capacity Factor (%)	2024 CAS Capacity Factor (%)	Delta (%)
Nuclear	41,388	42,428	91.5%	93.8%	2.30%
Coal	126,675	131,080	80.5%	87.4%	6.93%
CC	140,335	169,852	46.3%	46.8%	0.54%
CT & IC	20,024	18,493	20.0%	14.8%	-5.17%
Gas Steam	4,165	2,796	3.8%	4.2%	0.40%
Hydro	24	108	0.5%	2.4%	1.84%
Solar	623	9,108	28.9%	29.3%	0.43%
Wind	59,110	72,852	38.1%	38.4%	0.24%

Note: The generation (GWh) and capacity factors (%) shown in this table include all PUN generation. Typical ERCOT historical reports do not include the PUN generation in this manner.

b. Headroom

Headroom decreases significantly between 2016 and 2024 cases due mostly to increased penetration of renewables. Despite the increased penetration in renewables there is more total commitment from thermal generation 2024 than in 2016 due to net load increases. However the capacity-factor-while-committed of the thermal units also increases, meaning they contribute less to headroom. Therefore, the reduction in total contribution of thermal generation to overall load, especially in the nighttime hours when wind production is highest, leads to decreased headroom. Figure A-5 illustrates the headroom changes between 2016 CAS and 2024 CAS.

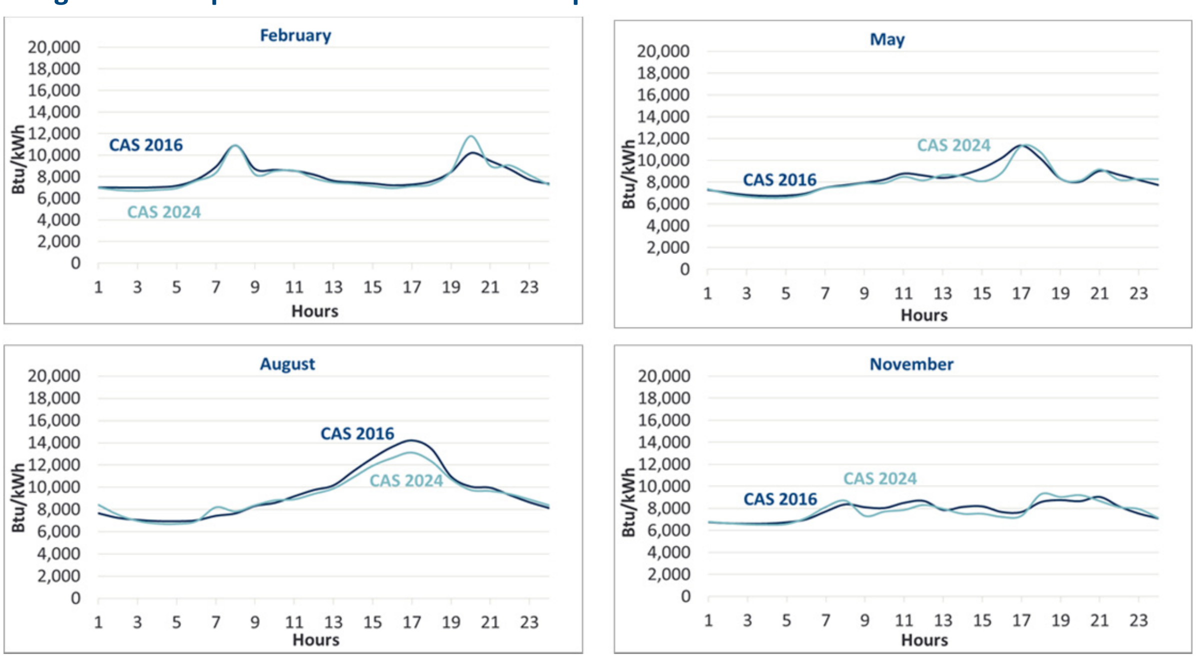
Figure A-5: Headroom Comparison between 2016 CAS and 2024 CAS



c. *Implied Market Heat Rates*

The 2024 Current Trends case has a similar resource mix to the 2016 case, except for higher renewable capacity. As a result, we would expect similar implied market heat rate between the cases. Figure A-6 corroborates our expectations as the implied heat rates did not show significant variance between 2016 and 2024.

Figure A-6: Implied Market Heat Rate Comparison 2016 CAS to 2024 CAS – Select Months



d. *Average Annual Reserve Contribution by Unit Type*

Combined-cycle units contribute more to annual reserves in the 2024 cases than in the 2016 cases due to their increased dominance in the resource mix. Table A-11 summarizes the AS procurement differences between 2016 CAS and 2024 CAS.

Table A-11: Benchmark AS Procurement by Unit Type

	2016 CAS Case				2024 CAS Case				Difference (2016 CAS - 2024 CAS)			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)
Coal	6%	9%	25%	0%	2%	2%	22%	0%	4%	7%	3%	0%
CC	34%	70%	66%	15%	39%	83%	73%	14%	-6%	-12%	-7%	1%
CT & IC	3%	13%	8%	82%	2%	10%	4%	84%	1%	3%	4%	-2%
Gas Steam	2%	4%	1%	3%	1%	2%	0%	2%	1%	2%	0%	2%
Hydro	9%	0%	0%	0%	9%	0%	0%	0%	0%	0%	0%	0%
Load Resources	48%	0%	0%	0%	48%	0%	0%	0%	0%	0%	0%	0%
Battery	0%	4%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**0%**	**0%**	**0%**	**0%**

II. Impact of FAS Before Adding New Technology

A. Inputs and Results for 2016 CT FAS vs. 2016 CT CAS

1. Assumptions

The 2016 CT CAS and FAS had identical inputs aside from reserve types, reserve requirement quantities, and any necessary changes to resource reserve capabilities to ensure a fair comparison on AS design impacts. Table A-12 summarizes the reserve requirements for each case.

Table A-12: 2016 CT Average Reserve Requirements (MW)

	CAS	FAS	(FAS - CAS)
Reg Up	460	460	-
Reg Down	456	456	-
RRS	2,814	-	-
PFR+FFR (In PFR Terms)	-	3,245	-
Expected FFR	1,345	1,369	24
Expected PFR	1,468	1,329	(140)
CR	-	1,175	-
NSRS	1,931	-	-
SR	-	-	-

2. Capacity Factor Comparison

Since the load assumptions were held steady between the cases, average capacity factors by unit type remained virtually the same. The interesting, though small, changes in capacity factors, summarized in Table A-13, are the increase in coal units and decrease in CC and CT & IC units. The changes for coal units came from increased dispatch in overnight winter hours. Correspondingly, CC unit dispatch decreased in the overnight winter hours. The CT & IC capacity factor reduction was spread more evenly throughout the year, on specific hours with lower PFR requirements.

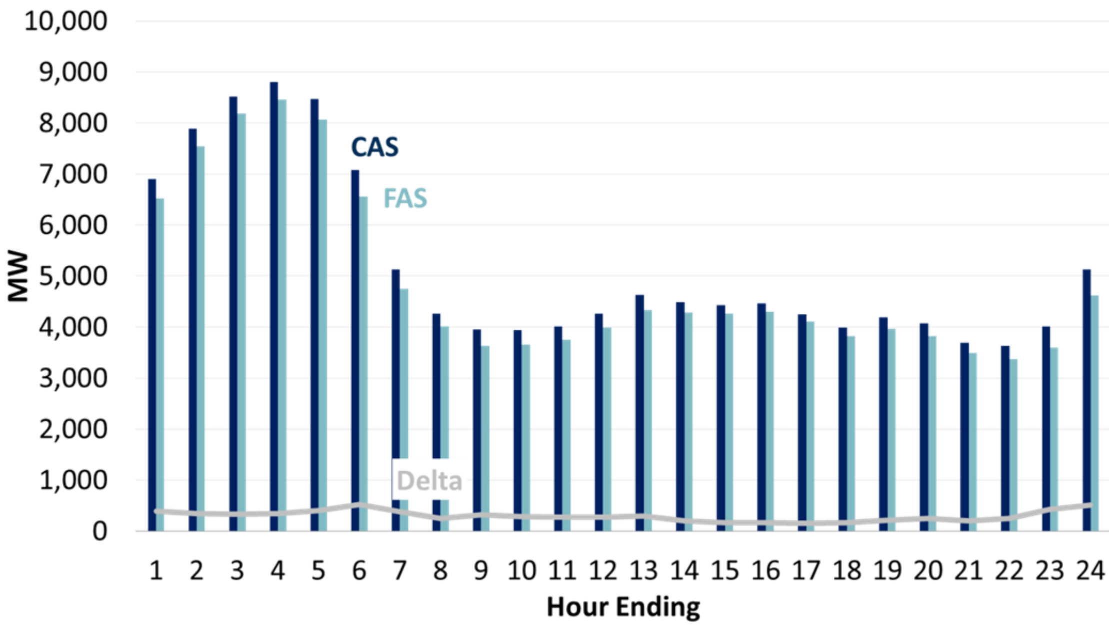
Table A-13: Capacity Factor Comparison between 2016 CAS and 2016 FAS

Type	2016 CAS Generation (GWh)	2016 FAS Generation (GWh)	2016 CAS Capacity Factor (%)	2016 FAS Capacity Factor (%)	Delta (%)
Nuclear	41,388	41,388	91.5%	91.5%	0.00%
Coal	126,675	127,689	80.5%	81.1%	0.64%
CC	140,335	139,617	46.3%	46.0%	-0.24%
CT & IC	20,024	19,791	20.0%	19.7%	-0.23%
Gas Steam	4,165	4,089	3.8%	3.7%	-0.07%
Hydro	24	26	0.5%	0.6%	0.05%
Solar	623	623	28.9%	28.9%	0.00%
Wind	59,110	59,110	38.1%	38.1%	0.00%

3. Headroom

While the reserve requirement changes had a small impact on energy capacity factors, they had a visible impact on the model's commitment patterns. With lower reserve requirements the model is able to find a more efficient commitment with lower headroom amounts. As shown in Figure A-7 the overnight headroom is decreased more on average than the daytime headroom. This change is caused by CC to Coal overnight switches, enabled by the lower PFR requirements (CCs are no longer committed and run at minimum load just to satisfy reserve requirements, meaning coal units do not have to be backed down from their energy dispatch to avoid over generation).

Figure A-7: Headroom Analysis Comparison



4. Energy and Ancillary Service Price Comparison

FAS's tighter commitment leads to slightly higher energy prices, as summarized in Table A-14, due to certain hours of CT commitment in FAS where CAS could cover with already committed units. However, regulation up and RRS/PFR prices in FAS are significantly cheaper because of the reduced PFR requirement. Regulation Up prices are affected because many of the same resources provide Regulation Up as provide RRS/PFR.

Table A-14: Annual Average Price ($/MWh)

	2016	
Product	**CAS**	**FAS**
Energy	$36.16	$36.58
Non-Spin or CRS	$0.01	$0.04
Regulation Down	$0.02	$0.07
Regulation Up	$4.25	$3.35
RRS or PFR	$4.25	$3.31

5. Average Annual Reserve Contribution by Unit Type

Table A-15 summarizes the changes in percentage of AS procurement by each unit type in the CAS and FAS cases. Corresponding to the commitment and dispatch changes observed among coal and CC units, coal provides more PFR and regulation up in the FAS case and CCs provide less. Contingency Reserve service in FAS can be provided by either online or offline resources, but they must respond within 10 minutes—for which offline CCs do not qualify, which is why Contingency Reserve services are provided primarily from CTs and ICs.

Table A-15: Procurement breakdown of AS between Provider Types

	2016 CAS Case				2016 FAS Case			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	PFR/FFR (%)	Reg Up (%)	Reg Down (%)	CR (%)
Coal	6%	9%	25%	0%	6%	5%	4%	0%
CC	34%	70%	66%	15%	29%	78%	83%	5%
CT & IC	3%	13%	8%	82%	2%	9%	12%	95%
Gas Steam	2%	4%	1%	3%	3%	7%	1%	0%
Hydro	9%	0%	0%	0%	8%	0%	0%	0%
Load Resources	48%	0%	0%	0%	51%	0%	0%	0%
Battery	0%	4%	0%	0%	1%	0%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

B. Inputs and Results for 2024 CT FAS vs. 2024 CT CAS

1. Assumptions

The 2024 Current Trends cases for CAS and FAS had identical inputs aside from reserve types, reserve requirement quantities, and any necessary changes to resource reserve capabilities to ensure a fair comparison on AS design impacts. Table A-16 summarizes the reserve requirements for each case.

Table A-16: 2024 Average Reserve Requirements (MW)

	CAS	FAS	(FAS - CAS)
Reg Up	499	499	-
Reg Down	495	495	-
RRS	2,785	-	-
PFR+FFR (In PFR Terms)	-	3,165	-
Expected FFR	1,332	1,345	13
Expected PFR	1,453	1,325	(129)
CR	-	1,210	-
NSRS	2,000	-	-
SR	-	-	-

2. Capacity Factor Comparison

In the 2024 cases, the capacity factors of CCs increased while the capacity factors of CTs & ICs decreased, as shown in Table A-17. Unlike the 2016 cases, in 2024 coal units are fully serving baseload duty, due to the increase in net load. With coal units already fully utilized, the reduced reserve requirements allow de-commitment of less efficient gas units and increased dispatch of more efficient units.

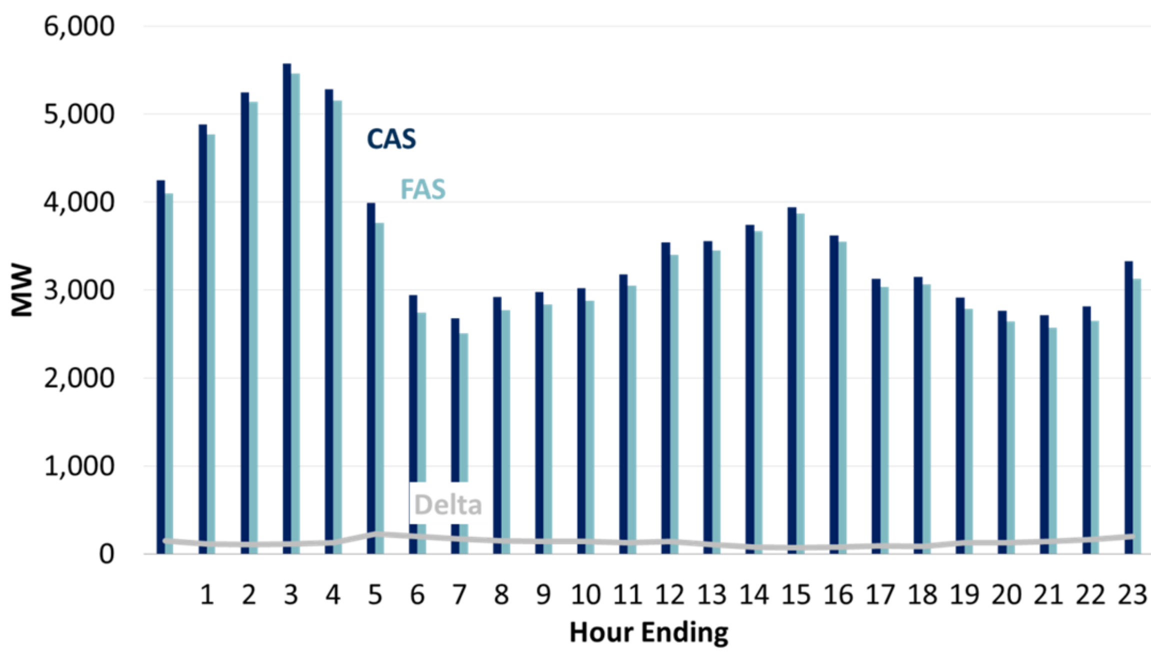
Table A-17: Capacity Factor Comparison between 2024 CAS and 2024 FAS

Type	2024 CAS Generation (GWh)	2024 FAS Generation (GWh)	2024 CAS Capacity Factor (%)	2024 FAS Capacity Factor (%)	Delta (%)
Nuclear	42,428	42,428	93.8%	93.8%	0.00%
Coal	131,080	131,133	87.4%	87.5%	0.04%
CC	169,852	170,805	46.8%	47.1%	0.26%
CT & IC	18,493	17,560	14.8%	14.0%	-0.75%
Gas Steam	2,796	2,722	4.2%	4.1%	-0.11%
Hydro	108	111	2.4%	2.4%	0.06%
Solar	9,108	9,108	29.3%	29.3%	0.00%
Wind	72,852	72,852	38.4%	38.4%	0.00%

3. Headroom

As in 2016, the 2024 FAS case has lower headroom than the CAS due to a more efficient dispatch enabled by lower reserve requirements. Unlike 2016, the reduction in headroom is very similar for every hour, as can be seen in the gray delta line in Figure A-8. The more even reduction is caused by the homogeneity of more efficient dispatch of gas units throughout the year and time of day.

Figure A-8: Headroom Analysis Comparison



4. Energy and Ancillary Service Price Comparison

As in the 2016 cases, FAS's tighter commitment leads to slightly higher energy prices. Table A-18 summarizes this change in energy prices and reserve prices.

Table A-18: Annual Average Price ($/MWh)

	2024	
Product	**CAS**	**FAS**
Energy	$48.64	$48.93
Non-Spin or CRS	$0.12	$0.16
Regulation Down	$0.01	$0.02
Regulation Up	$5.30	$4.91
RRS or PFR	$5.30	$4.95

5. Average Annual Reserve Contribution by Unit Type

Table A-19 shows that despite the changes to quantities of reserves, the percentage of reserves procured by unit type for upwards online reserves, regulation up and responsive reserves, barely changed between cases. As in 2016, CT & ICs provide more non-spin reserve in FAS than CAS because of the 10-minute CR requirement. FAS procures more regulation down from CCs and less from coal units, but because regulation down is valued at a zero or near-zero price in most hours, the requirement can be met equally cheaply by many resources.

Table A-19: Procurement breakdown of AS between Provider Types

	2024 CAS Case				2024 FAS Case			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	PFR/FFR (%)	Reg Up (%)	Reg Down (%)	CR (%)
Coal	2%	2%	22%	0%	3%	1%	4%	0%
CC	39%	83%	73%	14%	37%	86%	95%	5%
CT & IC	2%	10%	4%	84%	1%	8%	1%	95%
Gas Steam	1%	2%	0%	2%	1%	5%	0%	0%
Hydro	9%	0%	0%	0%	7%	0%	0%	0%
Load Resources	48%	0%	0%	0%	50%	0%	0%	0%
Battery	0%	3%	0%	0%	1%	0%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

III. Impact of FAS With New Technology (WNT)

A. Description of New Technologies Considered

New technologies exist that could provide AS but are not able to participate under the current AS framework. The new FFR1 product creates opportunities for fast-ramping (but low energy potential) technologies that would not qualify for current products. We completed an initial screen on flywheels, CAES, market DR, commercial and industrial DR, sodium sulfur batteries, and lithium ion batteries. We chose to model lithium ion batteries as a representative technology due to their relatively low capital costs. Other technologies may enter ERCOT's market as a result of the FAS design.

B. Inputs and Results for 2024 CT WNT FAS vs. 2024 CT CAS

1. Assumptions

We added a 62 MW battery to the original 2024 CT FAS case to create the 2024 CT WNT FAS. We sized the battery to fill the remaining quantity of FFR after accounting for the 2014 participation factor of load. Again, the expansion of load resources is a simplifying assumption for the PLEXOS modeling, but batteries or other new technology could fill the expanded FFR opportunity.

As expected, the dispatch and commitment changes between 2024 CAS and 2024 FAS NT are very similar to the changes between 2024 CAS and 2024 FAS NT.

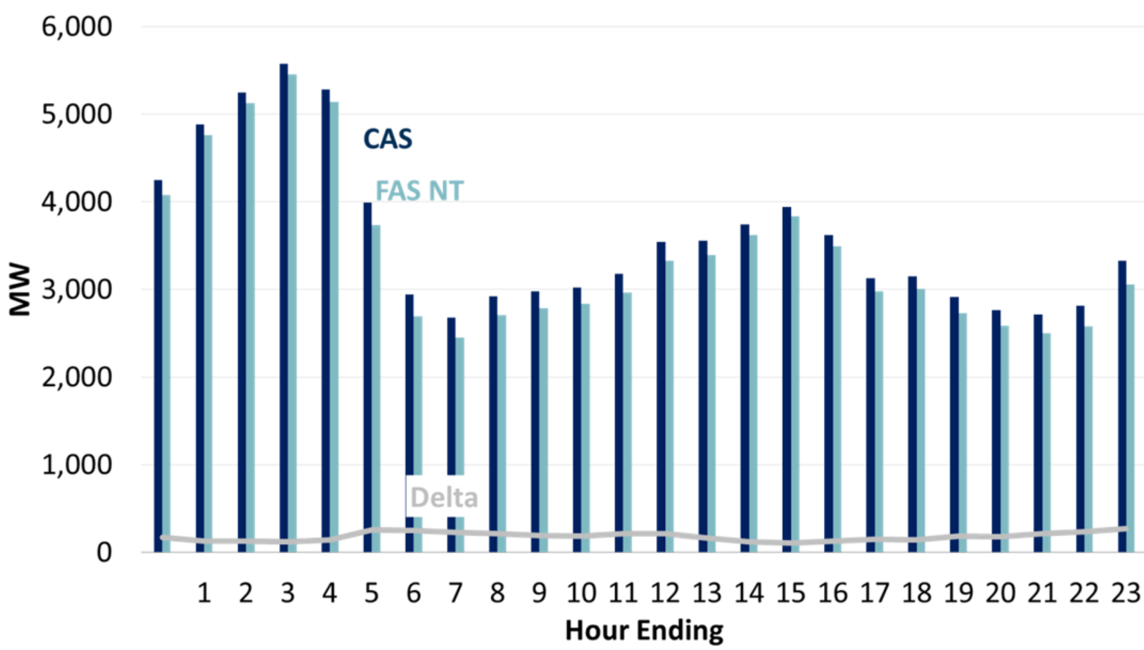
2. Capacity Factor Comparison

Table A-20: Capacity Factor Comparison between 2024 FAS and 2024 FAS NT

Type	2024 CAS Generation (GWh)	2024 FAS NT Generation (GWh)	2024 CAS Capacity Factor (%)	2024 FAS NT Capacity Factor (%)	Delta (%)
Nuclear	42,428	42,428	93.8%	93.8%	0.00%
Coal	131,080	131,187	87.4%	87.5%	0.07%
CC	169,852	170,793	46.8%	47.1%	0.26%
CT & IC	18,493	17,534	14.8%	14.0%	-0.77%
Gas Steam	2,796	2,709	4.2%	4.1%	-0.13%
Hydro	108	109	2.4%	2.4%	0.02%
Solar	9,108	9,108	29.3%	29.3%	0.00%
Wind	72,852	72,852	38.4%	38.4%	0.00%

3. Headroom

Figure A-9: Headroom Analysis Comparison



4. Energy Price Comparison

Table A-21: Annual Average Price ($/MWh)

	2024	
Product	**CAS**	**FAS NT**
Energy	$48.64	$48.82
Non-Spin or CRS	$0.12	$0.18
Regulation Down	$0.01	$0.02
Regulation Up	$5.30	$4.70
RRS or PFR	$5.30	$4.78

5. Average Annual Reserve Contribution by Unit Type

Table A-22: Procurement breakdown of AS between Provider Types

	2024 CAS Case				2024 FAS NT Case			
Type	RRS (%)	Reg Up (%)	Reg Down (%)	Non-Spin (%)	PFR/FFR (%)	Reg Up (%)	Reg Down (%)	CR (%)
Coal	2%	2%	22%	0%	2%	1%	3%	0%
CC	39%	83%	73%	14%	36%	81%	95%	5%
CT & IC	2%	10%	4%	84%	1%	7%	1%	95%
Gas Steam	1%	2%	0%	2%	1%	4%	0%	0%
Hydro	9%	0%	0%	0%	7%	0%	0%	0%
Load Resources	48%	0%	0%	0%	51%	0%	0%	0%
Battery	0%	3%	0%	0%	2%	7%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

IV. Real-Time Opportunity Cost

This section discusses in greater detail the analytical methods used to estimate the fleet-wide real-time opportunity costs in this study.

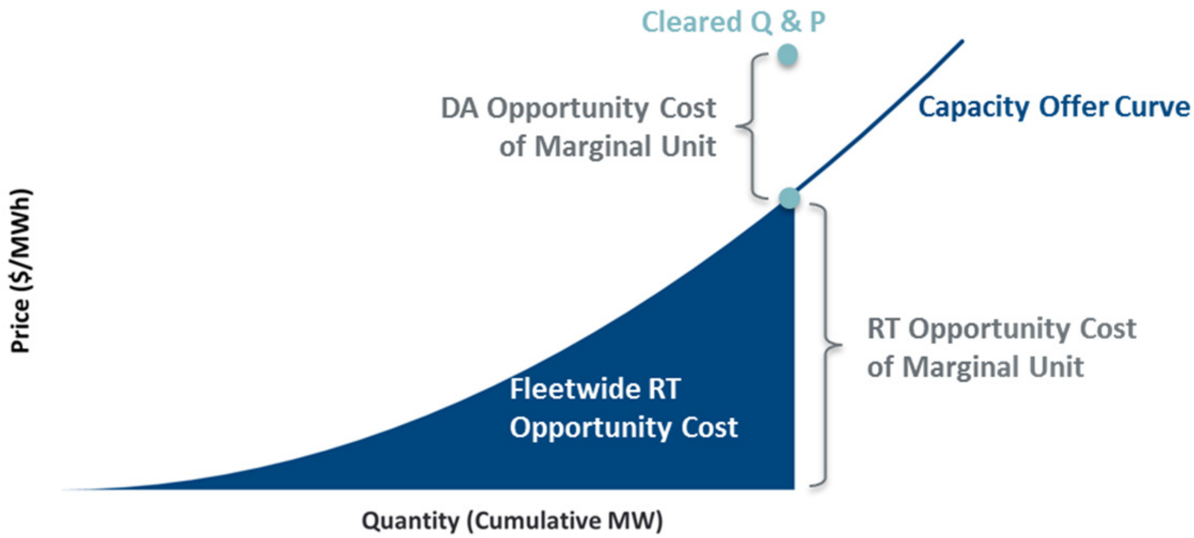
We chose to analyze the real-time opportunity cost savings outside of PLEXOS by using historical capacity offers provided by ERCOT. While we could have used these AS offers as inputs to PLEXOS, the modeled results would have had false precision due to our limited understanding of how offers vary by individual unit and unit type. Inputting individual offer profiles for each unit is difficult and nuanced. Therefore, modeling them in PLEXOS would have added an extra layer of uncertainty related to the offering process, making our day-ahead model overly and unnecessarily complex. To reduce complexity, we choose to separate the real-time analysis from the day-ahead analysis in order to help clarify our analytical steps and avoid obfuscation.

We used multiple data sources to quantify the real-time opportunity costs. First, ERCOT provided the hourly generating capacity offers into the AS Markets for 2014. We assume that these offers are competitive and represent real-time optionality foregone. Second, ERCOT provided the settle prices and quantities for the AS products analyzed. It is important to note that since the quantity of regulation products procured between CAS and FAS remained constant, we only analyzed NSRS/CR and RRS/PFR foregone real-time opportunity costs. Third, we used both the FAS and CAS ancillary service requirements for 2016 and 2024 discussed above in Section III. Finally, we removed the day-ahead energy opportunity costs of providing AS, that were captured in the 2016 CAS PLEXOS model from the 2014 settlement price in order to avoid overestimating real-time opportunity cost savings. Our goal was to capture only the capacity offer information in the final settlement price we used.

Before estimating the real-time opportunity cost for CAS and FAS in 2016 and 2024, we calculated the 2014 average real-time opportunity cost for each month-hour. The 2014 average values were then scaled based on the MW requirements in the 2016 and 2024 scenarios. Estimating the 2014 average real-time opportunity costs involved three main steps: (1) removing the day-ahead energy opportunity cost from the settlement price; (2) identifying the marginal AS provider by comparing the settlement price calculated in (1) to the an individual unit's offer on the offer curve; (3) calculating the area under the offer curve for all cleared units to estimate the fleet-wide real-time opportunity cost. We performed this calculation for all hours in 2014.

Our calculation does not represent customer costs, which would simply be the settlement price multiplied by quantity. Instead, it represents societal costs, including costs borne by producers, so it provides a more complete economic measure. Figure A-10 below is an illustrative example of the process for calculating these societal costs.

Figure A-10: Method for Calculating Fleet-Wide RT Opportunity Cost from Capacity Offers



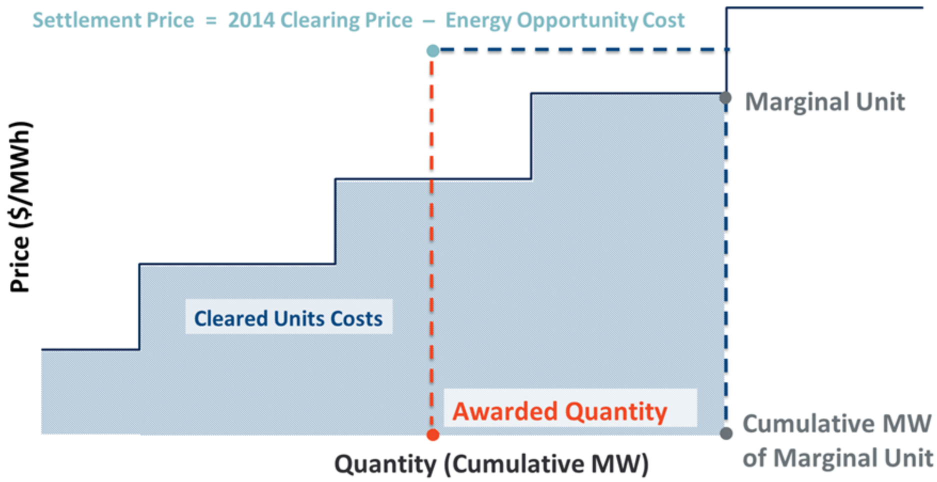
In many cases, the final settlement point did not actually fall perfectly onto the curve. In these cases, we assumed that some of the units that offered into the particular AS market cleared instead for energy or another AS product and therefore were not available. To account for these removed units in our fleet-wide real-time opportunity cost estimate, we added two additional steps into the method described above. First, we designated cleared units as those with offer prices less than or equal to the final settlement price. However, it could be that the cumulative MW of these newly labeled "cleared" units exceeds the total quantity of AS procured in that hour. To ensure that this method does not overestimate costs by including extra quantities, we applied an adjustment ratio to remove a portion of the additional cleared units' costs. The adjustment ratio and final costs are calculated using the formulas below:

$$Adjustment\ ratio = \frac{Awarded\ Quantity}{Cumulative\ MW\ of\ final\ cleared\ unit} \qquad \text{(Eq. 1)}$$

$$Fleetwide\ RT\ Oppy.Cost = Cleared\ Unit\ Costs * Adjustment\ ratio \qquad \text{(Eq. 2)}$$

where the awarded quantity is the settlement point quantity, the cumulative MW of final cleared unit is the total quantity procured using the price method's cleared unit designation, and the cleared unit costs are a sum product of the cleared units' individual MW offer and $/MWh offer price. Figure A-11 shows this calculation method on a step-wise offer curve.

Figure A-11: Illustration of Adjusted Opportunity Cost Calculation



We used the results from our 2014 analysis to estimate the fleet-wide RT opportunity cost for future cases, scaling costs to the quantities of ancillary services. We assumed that real-time opportunity cost will not vary due to new AS frameworks and varying system conditions when performing this scaling. However, it is possible that the capacity offers are not invariant as system conditions and AS frameworks change. To account for this uncertainty, we use average real-time costs rather than marginal avoided costs in order to increase our overall conservatism towards potential real-time savings in the FAS redesign. Complete results from this analysis are discussed above in Section IV.C.