Three-Stage Variability-Based Reserve Modifiers for Enhancing Flexibility Reserve Requirements Under High Variable Generation Penetrations

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Abstract—The electric power system has continuously evolved in order to accommodate new technologies and operating strategies. As the penetration of integrated variable generation in the system increases, it is beneficial to develop strategies that can help mitigate their effect on the grid, namely increased uncertainty and variability. Historically, power system operators have held excess capacity during the commitment and dispatch process to allow the system to handle unforeseen load ramping events in the form of operating reserves. Regulation reserves are ubiquitous, but a new category –commonly known as flexibility reserve– is being used more extensively throughout different footprints. As variable generation resources increase, sufficient flexibility scheduled in the system is required to ensure that system performance is not deteriorated in the presence of additional variability and uncertainty. This paper presents a systematic comparison of various flexibility reserve strategies. Several of them are implemented and applied in a common test system, in order to evaluate their effect on the economic and reliable

operation of the system. Furthermore, a three stage reserve modifier algorithm is proposed and evaluated for its ability to improve system performance.

Key Words—Area control error (ACE), flexibility reserves, variable generation (VG), mixed integer programming (MIP), operating reserves, uncertainty, variability

1. Introduction

Power system operations are subject to inherent uncertainty and variability. For example, the system operator cannot have perfect knowledge of the system load and its characteristics; equipment failures are not scheduled; weather patterns and their implications on customer behavior cannot be perfectly predicted. The integration of variable generation (VG) technologies (e.g., wind and solar PV) and electric vehicles only compounds this issue. As a result, the methods with which system operators mitigate this variability and uncertainty must be refined to ensure that the system operates economically, efficiently and reliably. Along with improved forecasts, the use of operating reserves is a wide spread strategy. Operating reserves are defined as excess capacity scheduled above (for upward reserves) or withheld below (for downward reserves) the dispatch in order to meet the expected average electrical demand at subsequent temporal resolutions [1]. There are many types of operating reserves, each with its own objective in terms of system operation. This paper will focus on flexibility reserves (also known as “flex” or “ramping” reserves), which aim to mitigate large ramps in the net load with durations ranging from a few seconds to several minutes. Traditional load-following reserves are used to meet the expected variations occurring in the load profile. This new class of flexibility reserves are

designed to help meet the unexpected variations occurring in the net load. The magnitude and ramp rate of these ramps are typically exacerbated by the presence of solar PV and wind generators.

Flexibility reserves are still in their infancy and there is not a set of accepted, industry-wide standards. This paper aims to propose a systematic methodology to compare several different types of flexibility reserve requirement calculation methodologies used in industry and literature with respect to their impact on system operations. By examining different reserve calculation methodologies and their effects on production cost and reliability, new operating strategies can be developed and tested. In this case, a new three-stage reserve modification algorithm is proposed to achieve an improved reserve requirement based on realized variability that can improve reliability metrics with minimal impacts on cost.

The rest of this paper is organized as follows: Section II provides a review of current flexibility reserve practices in industry and literature. Section III describes the simulation framework that will be used to perform the comparison. Section IV describes the test system that is used for this study. Section V presents the reserve methodologies that are implemented and compared in this analysis, followed by the proposed new three-stage flex reserve modifier algorithm. Section VI describes the numerical results, and Section VII concludes the paper with conclusions and final remarks.

2. Literature Review

Reserve strategies are typically developed in response to operating challenges in a given footprint, which has led to a lack of industry-wide standards regarding the calculation

of operating reserve requirements and the effect that variable generation (VG) has on them. This is true for both contingency and, especially, regulation reserves. The authors of [2] present a modified price clearing model to be incorporated into the Midcontinent Independent System Operator's (MISO) market clearing models. This formulation allows the economic dispatch solution to be robust against potential operating conditions and reduces the number of real time scarcity pricing events. A scarcity event can occur when there is insufficient ramping capacity in the system. This is accomplished by positioning the system at the current time interval to adequately meet the demand in future dispatch intervals. The authors of [3] develop a modification to the California Independent System Operator's (CAISO) market clearing optimization that will schedule excess capacity. This capacity must be unloaded, ramp feasible, and dispatchable during any time interval. This capacity is scheduled in both the upward and downward directions. During the binding dispatch interval, this capacity is released and is no longer held in reserve. This method is also expected to be able to reduce the number of real time scarcity pricing events due to insufficient ramping capacity.

The authors of [4] present an additional ancillary service product in the form of scheduled excess capacity in the system. The magnitude of this reserve requirement is dependent on the wind and solar generation forecast errors. The geometric sum of forecast errors covering a 70% confidence interval is used to calculate the requirements. The main goal for this product is to provide a simple implementation into current market clearing optimizations that can account for the additional variability and uncertainty introduced by wind and solar generation. This method can be easily extended to account for load forecast errors as well. The Electric Reliability Council of Texas uses the non-spinning reserve

service to address the forecast errors in the net load when there is not sufficient capacity already online to provide a secure dispatch [5]. First, the 95th percentile of net load forecast error from the previous 30 days as well as from the same month for the previous year are calculated. Then, the requirement is computed based on the maximum of these forecast errors. The requirement is limited to the capacity of the largest conventional generator within the region footprint.

There has also been some research regarding the scheduling of reserves in the presence of additional variable generation although not necessarily focusing on flexibility reserves. The authors of [6] propose a reliability-focused reserve product that is a function of the probability of load shedding. The authors of [7] present a general operating reserves product that aims to reduce the Energy Expectation Not Served (EENS). The authors of [8] present a methodology to determine the amount of spinning reserve required in systems with significant wind penetrations to account for potential generator outages and forecast errors. The authors of [9] develop a risk-based reserve management tool to aid system operators in setting the operating reserve requirements. This tool is designed to mitigate the Loss of Load Probability (LOLP) and determine reserve requirements that enforce the maximum allowable load shedding risk to the system operator. In [10], the operational effects of flexibility reserves on production costs and system imbalance are examined. By including the flexibility reserve requirements, additional thermal capacity is committed that could potentially eliminate scarcity price events while minimally impacting the system balance. The authors of [11] propose allocating the responsibility of generators for accommodating variability and uncertainty based on a new metric called the grid-balancing metric. This method does not assume any type of probability distribution regarding the

variability so it can be generally applied.

While the above flexibility reserve methods [2]-[11] focus on deterministic reserve requirements, there is some research focusing on stochastic operating models under the assumption that these models better capture the inherent stochastic nature of power system variables including load, wind, and solar generation [12]-[18]. The authors of [19] explore the difference in operator dispatch decisions between using a deterministic reserve requirement and using a stochastic operating model without an explicit reserve requirement. While the solution with the deterministic reserve requirement may produce similar dispatch solutions if appropriately sized, the dispatch solution with the deterministic reserve requirement may not be the least-cost solution.

The main contributions of this paper can be summarized as follows. System operators design their reserve requirements based on their own needs. This paper compares several different reserve methods on a single system to extract the operational implications common to all methods. This analysis is performed with fine temporal resolution, down to 5 minute dispatch with 4 second AGC control. Finally, a reserve modification method is adapted that can provide a net-benefit to all cases based on their common operation implications discovered in the analysis.

3. Reserve Methodology

The reserve methodologies implemented for this comparison study can be divided into three different categories, depending on the nature of their calculations. The first category consists of reserve calculations that are only based on load characteristics. The flexibility reserve requirement is calculated so that it covers 70% of the hour-ahead load

forecast errors (close to one standard deviation, if the underlying distribution was normal).

This method was implemented a second time with the flexibility reserve requirement reduced to only cover 50% of the hour-ahead load forecast errors. This reduction is done to observe the implications of less conservative reserve requirements. One more case was developed to investigate the difference between a dynamic and a static requirement. Thus, the requirements with 70% coverage were averaged and that mean value is applied as a constant value across the year.

The second category of reserve requirements is based on the variability of power system. In order to compare this type of method, a reserve requirement inspired by [4] and utilized in the Western Wind and Solar Integration Study Phase 2 by the National Renewable Energy Laboratory [22] was used. This flexibility reserve requirement can be seen in equation 1. Again, this method was implemented a second time with a reduced level of coverage of 50% of the forecast errors. These methods examine the forecast errors independently and combine their total requirements as the root of sum of square of each requirement.

$$Flex\ req = \sqrt{\Phi70_{hour-load}^2 + \Phi70_{hour-wind}^2 + \Phi70_{hour-PV}^2} \quad (1)$$

The third category of these operating reserve methods is calculated based on the variability of the net load profile. Rather than calculating the individual contributions, all of the profiles are added together and the net load forecast errors are used to determine the actual reserve requirements. In order to compare this type of reserve method, a reserve requirement inspired by the MISO [2] and ERCOT [5] was developed. This method calculates the requirement that covers 95% of day-ahead net load forecast error, with a

maximum cap equal to the capacity of the largest unit in the system (700 MW for this system). The largest 5% of intervals showing under forecasting are excluded from the calculations. This was done as a sensitivity to demonstrate the impact of highly conservative flexibility reserve requirements. A second case was calculated reducing the coverage to 90%. These requirements are set for the upward direction only since there is no documentation regarding a downward requirement. An in-depth analysis of similar reserve methods can be found in [25]. Finally, a baseline case with no flexibility reserve was added. Table I summarizes the cases simulated in the study.

Table I SUMMARY OF SCENARIOS	
Name	Flexibility Reserve Calculation
Base	No flexibility reserve
Case 0	Static , based on Case 1 average
Case 1	Based on 70% of hour-ahead load forecast error
Case 2	Based on 50% of hour-ahead load forecast error
Case 3	Based on 70% of hour-ahead VG and load forecast error
Case 4	Based on 50% of hour-ahead VG and load forecast error
Case 5	Based on 95% of day-ahead net load forecast error
Case 6	Based on 90% of day-ahead net load forecast error

Table II provides a brief numerical summary of the flexibility reserve methodologies. The final column in this table represents the cumulative absolute sum of the reserve requirement over the entire study period. Cases 5 and 6 provide a conservative calculation for the flexibility reserve requirements compared to the other methods.

Table II NUMERICAL SUMMARY OF FLEX RESERVE METHODS				
	min	mean	max	sum
	[MW]	[MW]	[MW]	[TW-h]
Case 0	63.1	63.1	63.1	6.7
Case 1	53.1	63.1	71.5	6.7
Case 2	32.1	40.3	48.8	4.3
Case 3	55.0	123.4	306.8	13.0
Case 4	33.0	76.8	233.7	8.1
Case 5	261.2	646.2	700	68.1
Case 6	106.8	564.7	700	59.5

One thing common to all flexibility reserve methodologies is the focus on uncertainty in the form of forecast error. This paper presents a post mortem addendum to the reserve requirement in the form of a three stage modification process to account for the realized variability. By explicitly addressing the realized variability observed in the system, reliability metrics can be improved while minimizing the impacts on costs. These three stages are derived based on empirical observations of system operations. The three stage modification process is given below.

Step 1. Calculate modifier α_1 .

$$\alpha_1 = 1 - \frac{\text{Net Load}}{\text{Actual Load}} \quad (2)$$

Step 2. If $\alpha_1 \geq 0.70$, then increase down reserve requirement

If $\alpha_1 < 0.70$, then increase up reserve requirement

Step 3. Calculate modifier α_2 .

$$\alpha_2 = 1 - \frac{\text{Actual VG Output}}{\text{Maximum Possible VG Output}} \quad (3)$$

Step 4. If $\alpha_2 \leq 0.40$, then increase down reserve requirement

If $\alpha_2 > 0.40$, then increase up reserve requirement

Step 5. Calculate modifier α_3 .

$$\alpha_3 = \frac{\frac{1}{T} \int_T ACE(\tau) d\tau}{L_{10}} \quad (4)$$

Step 6. If $\alpha_3 > 0$, then increase down reserve requirement

If $\alpha_3 < 0$, then increase up reserve requirement

The modifier thresholds can be adjusted on a case-by-case basis. In this study, the alpha-1 threshold is selected as 0.7, alpha-2 threshold as 0.40, and alpha-3 threshold as 0. These thresholds are determined by the system operator and will vary case by case and system by system. The values used in this study were determined from analyzing the results of iterative empirical trials on the same system with varying thresholds. This method is reliability-based and is aimed at improving the reliability metrics. However, this could result in potentially significant economic savings if this improvement results in savings from potential NERC sanctions which can be greater than \$300,000 per incident [26].

The first stage of this process looks to determine whether or not the system is operating in the valleys of the net load profile. This indicates the times where the maximum amount of VG power is being deployed in the system. During these times, reserves in the downward direction are more valuable than upward reserves since upward generation can be obtained via VG curtailment. The second stage looks at the actual curtailment of VG power output. This indicates the magnitude of unutilized VG power that could potentially be deployed with proper adjustments from the thermal generation fleet. If the curtailment is exceeding some predefined threshold, in this case 40%, then the downward reserves are increased. This is intended to help mitigate curtailment occurring due to inflexible online capacity. The third stage looks into the actual ACE being realized in the system in real time. The numerator is the average of the last T minutes, in this case 5 minutes. The denominator is the L_{10} threshold from the NERC Compliance Performance Standard 2 for the balancing area being studied [27]. If this modifier is positive, positive ACE is being

accumulated, and the downward reserve requirement should be proportionally increased, and similarly for the case if the average ACE is negative. The modified requirement is capped so as not to exceed 2% of the actual load at the same time.

This modification process is not meant to supplant existing reserve methodologies but rather work in unison with them to improve system reliability. By including information based on actual system conditions, the modified reserve requirements become dynamic requirements that adjust in real-time to realized variability and uncertainty. Since these modifiers are system independent, operators can optimize their own reserve requirements on a system-by-system, case-by-case basis. Since the modifiers are changing the way the reserved capacity is utilized, costs are relatively unchanged compared to the cases without the modifiers since the commitment decisions are generally unaffected. This results with improving the reliability metrics while not worsening the cost metrics. Since this method is a simple rule based modification technique, it is easily implementable by a system operator without computational consequences.

4. Simulation Testbed

Different flexibility reserve strategies will be compared through the Flexible Energy Scheduling Tool for Integrating Variable generation (FESTIV) being developed by the National Renewable Energy Laboratory (NREL) [20]. FESTIV is able to simulate the scheduling of these flexibility reserve products and also their deployment. With this information, the implications of various flexibility reserve products on production cost and system imbalance can be investigated.

FESTIV produces valuable metrics that can be used to compare different reserve

methodologies. First, it produces the production cost, taken as the variable cost of energy as a function of the total production for each generator. Second, it produces the area control error (ACE) in the system as the difference between total generation and total demand. Third, prices and revenues are calculated. Using this information and market settlement rules, how and whether resources are being incentivized to act as directed can be investigated. More details about FESTIV can be found in [20].

This paper will focus on comparing the impacts of flexibility reserves on power system operations, namely production cost and reliability, utilizing the same test system for the different reserve strategies. The impact on reliability will be quantified in terms of area-wide imbalance, or ACE. This direct comparison will yield some insight into the best way to account for the additional variability and uncertainty introduced at high VG penetration levels.

5. System Description

The reserve methods were compared on a single, common system in order to extract the operational implications of each method. The system used in this study is a modified IEEE 118-bus test system [21]. The generation mix of this system was updated to better reflect a more realistic balancing area. In order to obtain a generation mix more representative of current U.S. systems, some coal plants were converted to combined cycle plants. Smaller plants were directly converted, e.g., a 200 MW coal plant was directly converted into a 200 MW combined cycle plant. Larger plants were split into multiple units, e.g., a 600 MW coal plant was converted into two 300 MW combined cycle units connected to the same bus. New coal and combined cycle generators with improved

flexibility (in terms of minimum capacity levels and per-minute ramp rates) were added to the system. These changes allowed the test system to better match current, available operating cost data. In addition to the modified generation fleet, load and VG time series were added to the study system based on available data for northern California [22]. Load and VG data were based on weather conditions in the year 2006. Wind and solar generation was added to the system to reach an approximate 33% average annual penetration based on deliverable energy. Since the main focus of this paper is to investigate flexibility reserves, the wind and solar generators were sited with the objective of only maximizing their access to transmission to minimize the amount of curtailment that would occur due to congestion.

In order to capture the seasonal trends in load and VG data, the system was simulated for four separate, equally-distributed weeks throughout the year. The system was simulated for the third week in January, April, July, and October. For short term wind forecasts, a 10 minute persistence forecast was used. This means that the actual wind power output occurring at the present time interval will be used as the forecast of the next 10 minutes. A persistent cloud cover forecast was used for the short term solar generation forecasts. This method is described in [5]. Hour-ahead load forecasts are based on [23]. These forecasting techniques are important to ensure reasonable forecast errors to truly test the ability of these flexibility reserve techniques in preparing the system for ramping events. A summary of the characteristics of the new test system is shown in Table III.

Table III UPDATED IEEE 118 BUS TEST SYSTEM CHARACTERISTICS	
System Characteristics	
Coal Capacity [TW]	2.3
Combined Cycle Capacity [TW]	2.76
Combustion Turbine Capacity [TW]	2.52
Peak Load [TW]	6.9
Annual Solar Energy Penetration [%]	17.45
Annual Wind Energy Penetration [%]	16.98

Regulations reserves were determined based on a simple rule of 1% of load.

Contingency reserves were set at 6% of load (3% for spinning and 3% for non-spinning).

These requirements mimic many long-term transmission operational studies in the industry, such as Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee (TEPPC) [24]. Although flexibility reserve varies across scenarios, regulation and contingency requirements are kept constant.

6. Results

Table IV shows a summary of the results, for the following metrics: production cost, number of price spikes (i.e., number of intervals with energy prices exceeding 1000 \$/MWh), absolute ACE in energy (AACEE, the integral of the absolute value of ACE), and standard deviation of ACE (σ_{ACE}). **In brief**, based on these results, scheduling of flexibility reserves has negligible impacts on total system productions cost for cases 0 through 4, when compared to the base case. However, production cost increased noticeably in cases 5 and 6. This is due to the larger magnitude of the requirements, which increased thermal commitments in the system. **There is also a significant reduction in the number of price spikes across the board. This is important because one of the main advantages of these flexibility reserves is their ability to reduce the number of price spikes occurring in the real time market due to a shortage of ramping capacity, as will be discussed later. There is**

mixed performance with respect to the reliability metrics, namely the absolute ACE in energy, or AACEE, and the standard deviation of the ACE. While most cases showed a reduction in the amount of AACEE, there are some cases that show an increase. This is partially due to the commitment decisions being made by the operator during times of peak demand and reserve requirements. This is expected since during these times, the operator may choose to commit larger, slower units to fulfil energy requirements over the smaller, faster units. Similar trends can be observed in the standard deviation of the ACE as well (the last column in Table IV).

One of the potential benefits outlined in literature [2] [3] is the reduction of price spikes appearing in the real-time prices. Analysis of the results shows that including the flexibility reserve requirement provides a substantial reduction in the number of price spikes and in some cases (e.g., January Cases 5 and 6 and April Case 5) completely eliminates their occurrence. This is directly related to the commitment of additional capacity that avoids periods of limited ramping in the system. As a result, the system is better positioned to handle the variability in the VG and load.

Fig. 1 shows price duration curves for the week in October for all cases. Note that the vertical axis scale stops at \$100/MWh. The net load based method (case 5) shows the fastest decline in price spikes as expected due to its conservative calculation method. The price depression is moderate for case 3. Another interesting result is the number of intervals with a price of zero \$/MWh, which are directly linked to periods of curtailment. Because

Table IV
NUMERICAL RESULTS WITHOUT THREE STAGE RESERVE MODIFICATION

Month	Case	Cost [million \$]	Δ Cost	Number Of Price Spikes	Δ Number of Price Spikes	AACEE [MWh]	Δ AACEE	σ_{ACE} [MW]	$\Delta \sigma_{ACE}$
January	Base Case	12.44	—	226	—	2,201	—	25.3	—
	Case 0	12.49	0.3%	160	-29.2%	2,379	8.08%	28.6	13.0%
	Case 1	12.42	-0.2%	176	-22.1%	2,145	-2.52%	24.8	-2.0%
	Case 2	12.40	-0.3%	179	-20.8%	2,160	-1.85%	25.0	-1.1%
	Case 3	12.17	-2.2%	104	-54.0%	2,070	-5.92%	23.2	-8.0%
	Case 4	12.53	0.7%	118	-47.8%	2,023	-8.06%	23.4	-7.4%
	Case 5	13.09	5.2%	0	-100%	1,903	-13.52%	22.6	-10.8%
	Case 6	12.95	4.1%	0	-100%	1,883	-14.44%	21.6	-14.6%
April	Base Case	7.83	—	219	—	3,044	—	39.4	—
	Case 0	7.85	0.2%	206	-5.9%	3,184	4.58%	44.5	13.0%
	Case 1	7.92	1.0%	199	-9.1%	2,993	-1.70%	40.4	2.5%
	Case 2	7.87	0.5%	192	-12.3%	2,815	-7.53%	37.6	-4.6%
	Case 3	8.018	2.4%	161	-26.5%	2,880	-5.39%	39.1	-0.8%
	Case 4	7.987	2.0%	166	-24.2%	3,026	-0.60%	40.7	3.1%
	Case 5	9.279	18.4%	0	-100%	3,341	9.73%	50.9	29.0%
	Case 6	8.982	14.7%	3	-98.6%	3,061	0.54%	44.8	13.7%
July	Base Case	17.74	—	459	—	5,522	—	94.4	—
	Case 0	17.92	1.1%	425	-7.4%	4,264	-22.78%	70.0	-25.8%
	Case 1	17.93	1.1%	425	-7.4%	4,959	-10.19%	87.0	-7.8%
	Case 2	17.90	0.91%	448	-2.4%	4,887	-11.50%	83.3	-11.7%
	Case 3	17.56	-0.98%	366	-20.3%	2,675	-51.55%	51.0	-45.9%
	Case 4	18.12	2.2%	412	-10.2%	3,960	-28.28%	66.1	-30.0%
	Case 5	18.27	3.0%	31	-93.3%	1,063	-80.74%	11.9	-87.4%
	Case 6	18.46	4.1%	53	-88.5%	1,060	-80.81%	11.8	-87.5%
October	Base Case	9.09	—	130	—	2,117	—	27.6	—
	Case 0	9.09	0.1%	91	-30.0%	2,151	1.64%	29.0	4.8%
	Case 1	9.11	0.2%	99	-23.9%	2,101	-0.72%	27.6	0.01%
	Case 2	9.16	0.8%	116	-10.8%	2,264	6.96%	30.7	11.3%
	Case 3	9.12	0.4%	59	-54.6%	2,135	0.86%	30.5	10.6%
	Case 4	9.12	0.4%	79	-39.2%	2,044	-3.44%	26.9	-2.7%
	Case 5	10.16	11.8%	1	-99.2%	2,223	5.02%	33.5	21.4%
	Case 6	9.94	9.4%	2	-98.5%	2,187	3.35%	31.6	14.5%

more capacity is available online for case 5, the minimum generation level of the thermal generators is higher and VG is curtailed more often than the other cases.

Fig. 1. LMP duration curve during the October simulations

Fig. 2 shows the mean-absolute difference between the day-ahead (DA) and real time (RT) prices. The addition of the flexibility reserve requirements does help in reducing the discrepancies between the day-ahead and real time prices (5 minute market clearing). The most conservative requirement (net load based calculation requirements, cases 5 and 6) greatly reduces this difference. In general, all flexibility reserve requirements helped reduce the difference between the day-ahead and real time LMPs compared to the base case simulation in which the flexibility reserve was not included.

Table V shows the changes in numerical results after adding the three-stage modifiers. The percentages are based on the change in results from Table IV. The columns are, starting from the left, change in production cost, change in AACEE, change in the standard deviation of the ACE, change in the number of real time prices spikes, change in the mean absolute difference between the DA and RT LMPs, change in VG curtailment, and the change in real time market infeasibilities. The real time market infeasibilities represent intervals where the RTSCED solution was not feasible and as a result, some

amount of load was unserved or excess thermal generation was committed. For example, for Case 3 simulated in July, including the 3-stage reserve modifiers reduced the production cost by 1.3%, reduced AACEE by 16.0%, reduced the standard deviation of the ACE by 2.3%, reduced the number of RT price spikes 28.1%, etc. In general, all of the reliability metrics are further reduced by including the 3-stage modifiers with minimal impact on production costs. This is reflected in the last row in Table V which summarizes the average total impact for each metric. In brief, the three-stage modifiers are able to further reduce the amount of AACEE, price spikes, and curtailment in the system. They help reduce the variability in the imbalance (standard deviation of the ACE). They also help reduce the divergence between day-ahead and real-time energy market prices all while minimally impacting total system production costs. There are some instances that show large increases in the percent impact, this is due to small changes in relatively small values. For example, in July Case 3, the real time market infeasibilities increases by 18.3%. However, numerically, this is the percent difference between 0.93 MWh and 1.1 MWh. Similarly, in October Case 5, the number of price spikes increases from one to two.

Fig. 2. Mean-Absolute difference between DA and RT LMPs

Further, the inclusion of flexibility reserves can potentially significantly impact the system imbalance. In general, the imbalance is reduced, both in terms of the actual amount of imbalance being realized (the AACEE) and the variability of the imbalance (σ_{ACE}). There is potential for the imbalance to be negatively impacted. This could happen if the additional flexibility requirement results in committing slower, thermal generators to fulfil

Table V
NUMERICAL RESULTS WITH THREE STAGE RESERVE MODIFICATION

Month	Case	Δ COST	Δ AACEE	$\Delta \sigma_{ACE}$	Δ Number of Price Spikes	Δ MAPD	Δ Curt.	Δ RT Inf.
January	Case 0	-4.0%	-21.2%	-22.6%	-50.0%	-4.5%	1.2%	-91.8%
	Case 1	-0.4%	-13.4%	-11.3%	-51.1%	-8.3%	0.7%	-79.8%
	Case 2	-0.2%	-14.9%	-14.7%	-52.0%	-14.3%	3.3%	-88.7%
	Case 3	2.1%	-11.0%	-8.3%	-57.7%	2.2%	9.3%	-78.7%
	Case 4	-0.8%	-8.4%	-6.9%	-39.8%	-8.6%	-8.1%	-68.3%
	Case 5	-1.3%	0.3%	7.6%	-	11.2%	-4.1%	-
	Case 6	-0.2%	-1.3%	5.7%	-	-5.4%	-4.6%	-
April	Case 0	2.7%	-16.3%	-10.3%	-45.6%	-6.2%	-1.3%	-74.6%
	Case 1	1.5%	-14.5%	-17.7%	-42.2%	-9.5%	-9.9%	-68.4%
	Case 2	1.5%	-6.0%	0.4%	-27.1%	-5.7%	-0.2%	-55.7%
	Case 3	1.9%	-13.9%	-10.8%	-55.9%	-8.9%	-5.7%	-55.3%
	Case 4	1.9%	-16.3%	-11.0%	-50.0%	-1.6%	-5.6%	-51.0%
	Case 5	-1.0%	-5.1%	-6.0%	-	-4.3%	-1.4%	-
	Case 6	0.6%	-1.4%	1.6%	-100%	-15.7%	-0.4%	-100%
July	Case 0	-1.1%	-13.7%	-7.8%	-9.6%	-11.0%	1.2%	-16.8%
	Case 1	-1.0%	-19.6%	-19.7%	-11.5%	-10.2%	1.2%	-23.9%
	Case 2	-0.8%	-24.0%	-15.4%	-18.8%	-15.6%	1.4%	-29.2%
	Case 3	-1.3%	-16.0%	-2.3%	-28.1%	-18.5%	0.4%	-25.0%
	Case 4	-2.0%	-9.0%	-6.3%	-7.8%	-17.0%	1.0%	-11.1%
	Case 5	1.9%	-6.4%	-6.5%	-48.4%	4.1%	0.7%	18.9%
	Case 6	-0.4%	-8.5%	-8.0%	-24.5%	-13.9%	3.3%	-65.3%
October	Case 0	0.7%	-14.7%	-16.1%	3.3%	2.8%	6.6%	-34.2%
	Case 1	1.0%	-13.0%	-13.3%	-17.2%	-1.3%	-1.4%	-20.6%
	Case 2	0.0%	-20.3%	-23.3%	-28.4%	-12.1%	6.4%	-44.2%
	Case 3	0.0%	-9.3%	-11.9%	-	1.2%	3.1%	-6.9%
	Case 4	0.6%	-10.1%	-10.1%	-27.8%	-4.5%	1.1%	-19.7%
	Case 5	-1.4%	-2.2%	-1.9%	100%	-0.5%	0.0%	2.5%
	Case 6	0.0%	3.7%	7.4%	-	2.1%	-1.1%	-57.8%
Average		0.02%	-10.95%	-8.56%	-30.02%	-6.2%	-0.1%	-39.8%

this requirement rather than relying on faster, more flexible combustion turbines.

As was discussed previously, the modification process is designed around operating statuses of the power system. As a result, the amount of benefit these modifiers can afford depend on how much the modifiers are allowed to modify the reserve requirement. Fig. 3 shows a comparison of production cost versus AACEE for different sensitivities controlling the amount that the modifiers are allowed to change of the reserve requirement for the January simulation week. The sensitivities consist of allowing the reserve modification process to change the reserve requirement by 0.5%, 1%, 2%, and 5%. Similar trends can be seen for the other weeks as well.

Fig. 3. Production cost vs. AACEE for different reserve modification levels in January.

The sensitivity analysis confirms that, **in general**, allowing the three-stage modification process to enhance the reserve requirements in real-time improves system reliability performance. The magnitude of this improvement depends on how much the requirement changes. **Note, there are some cases in figure 3 that do not show improvement. Adjusting the modifier parameters for these specific cases could result in improvement if**

the operator decides to do so. This figure compares the same parameter configuration across all cases to show the general behavior of the modification process, but it should be noted that any case can be adjusted on its own to meet the performance requirement for that specific case via the modification process.

7. Conclusion

As more variable generation is added to the power system, system operators can employ new strategies to help integrate them and minimize their impact on system reliability. This paper explored the operational impacts and benefits derived from the implementation of a new ancillary service product herein referred to as flexibility reserves. Different approaches to determine the amount of flexibility reserves, based on state-of-the-art research and industrial practices, are presented and compared. A three-stage reserve modification algorithm based on realized variability was proposed and implemented to better position the system to handle unexpected variations in load, wind, and solar profiles. The analysis in this paper produced the following results:

- 1) This paper performed a unique, apples-to-apples comparison of different flexibility reserve methodologies on a controlled system to directly analyze the operational impacts of these reserve products.
- 2) We corroborated the reduction in the frequency of price scarcity events, as reported in the literature; this is confirmed across all reserve cases in the simulations.
- 3) Flexibility reserve requirements can help converge day-ahead and real-time prices.

- 4) A three-stage reserve modification process was developed to work in conjunction with already existing reserve methodologies to improve system reliability metrics derived from system operation conditions.
- 5) Traditional flexibility reserve requirements are calculated beforehand and used as a static input into market clearing models. The proposed modification method in this paper modifies the reserve requirements based on realized variability in the system, providing a dynamic reserve requirement that constantly changes the reserve requirement based on what is actually happening in the power system.
- 6) The proposed rule-based algorithm is not computationally intensive and can easily be incorporated into any existing market model with minimal impact on solution time.
- 7) The three-stage modification process helps further improve the reliability metrics by further positioning the system to better account for the actual, realized variability occurring in the system with high VG penetrations while minimally impacting the total production cost.

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